# A Review of Mackenzie Delta-Beaufort Sea Petroleum Province Conventional and Non-conventional (gas hydrate) Petroleum Reserves and Undiscovered Resources: a contribution to the resource assessment of the proposed Mackenzie Delta-Beaufort Sea Marine Protected Areas

***Osadetz[1], K. G., Dixon[1], J., Dietrich[1], J. R., Snowdon[1], L. R., Dallimore[1], S. R., and Majorowicz[2], J. A.***

**[1]Geological Survey of Canada**
**[2]Northern Geothermal Consultants, Edmonton, Alberta**

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# ABSTRACT

The Beaufort-Mackenzie Basin hosts an immense petroleum resource. Fifty-two petroleum fields found by 263 wells, including four gas hydrate research wells, have discovered petroleum expected to be 172.75 X $10^6 m^3$ recoverable crude oil (RCO) and condensate and 254.67 X $10^9 m^3$ marketable conventional natural gas (MNG). The region is estimated to have an expected undiscovered 957.2 X $10^6 m^3$ RCO and 1.64 X $10^{12} m^3$ recoverable conventional natural gas. The conventional resources are co-located with an immense gas hydrate resource estimated between 2.4 X $10^{12}$ and 87 X $10^{12} m^3$ raw natural gas in place. Development of the, often co-located, gas hydrate petroleum resource could augment the conventional petroleum province significantly within the production life span of the conventional onshore fields.

The undiscovered gas in the Kendall Island and Kugmallit Bay regions of the proposed Mackenzie Delta – Beaufort Sea Marine Protected Area (MPA) is a portion of 356.94 X $10^9 m^3$ undiscovered gas, including possibly a gas field >28.33 X $10^9 m^3$ MNG gas plus the discovered gas within its boundaries. The inference of the total gas potential in the proposed MPA is not possible because there is no assessment of undiscovered gas potential in the West Beaufort play group, and therefore there is no basis for inferring the conventional natural gas potential of the Mackenzie Bay region of the proposed MPA. The total undiscovered crude oil potential in the proposed MPA is some fraction of 466 X $10^6 m^3$ recoverable crude oil that might include one undiscovered pool >16 X $10^6 m^3$ and multiple undiscovered pools >4.0 X $10^6 m^3$ in the Kendall Island and Kugmallit Bay regions and one to three crude oil pools >16 X $10^6 m^3$ and some fraction of the 12 undiscovered pools in the 3.97 to 15.87 X $10^6 m^3$ size range in the Mackenzie Bay region. Within the region of the MPA the total gas hydrate potential is estimated to be between 1.27 X $10^{10} m^3$ - 4.60 X $10^{11} m^3$ raw natural gas in place.

The specific impact and effect of three candidate Marine Protected Area (MPA) sites identified by the Department of Fisheries and Oceans (DFO) in the southern Canadian Beaufort Sea on the exploration, development and transportation of existing regional petroleum reserves and resources cannot be appropriately determined using the available sources of data and inference. There is no consensus regarding either the discovered reserve or the undiscovered potential among various stakeholder groups, based on the pre-2002 data set alone. Since 2002 much important new, confidential industrial data has been acquired.

# INTRODUCTION

This study reviews conventional and non-conventional (gas hydrate) petroleum resources of the Mackenzie Delta-Beaufort Sea region. It summarizes existing regional petroleum resources, the exploration, development and transportation of which might be affected or impacted by the three candidate Marine Protected Area (MPA) sites identified by the Department of Fisheries and Oceans (DFO) in the southern Canadian Beaufort Sea (Figure 1 – see Terms of Reference in Appendix 1). The proven conventional petroleum resources of the basin indicate that the Mackenzie Delta-Beaufort Sea has the potential to be a prolific producer of conventional natural gas and light oil, a potential that will begin to be realized with the construction of a natural gas pipeline to the Canadian Arctic, projected to come on stream towards the end of this decade.

## *LOCATION AND DEFINITION OF MARINE PROTECTED AREAS*

For the purposes of this report the three candidate MPA's are referred to as Mackenzie Bay, Kendall Island and Kugmallit Bay MPA's (Figure 1). The sites are located entirely in shallow waters of Mackenzie River estuaries with their landward boundaries defined by the low tide line. The MPA sites were defined based on the boundaries of the Zone 1a areas as established under the auspices of the Beaufort Sea Beluga Management Plan (BSBMP). At the present time, BSBMP guidelines exclude oil and gas exploration, production or related construction and mining/quarrying activities in these areas. Non-renewable resource assessments are required as part of the process of developing regulations that would define and govern the proposed MPA.

This paper describes the setting, discovery and assessment of conventional and non-conventional (gas hydrate) petroleum resources in the Beaufort Sea-Mackenzie Delta Basin (BMB) (Majorowicz and Osadetz, 2001, Dixon et al., 1995; Dixon et al., 1994). Gas hydrates were identified in the early stages of exploration (Bily and Dick, 1974). However, recent developments (Dallimore et al., in press; 1999) indicate that gas hydrates could contribute to the regional petroleum supply within the conventional reserve production lifetime. The BMB total petroleum potential is a strategic Canadian resource important for future North American petroleum supply. This paper discusses the petroleum potential of the proposed MPA, so far as it is possible, using available knowledge.

In addition, since the most recent determinations of conventional and non-conventional petroleum reserves and resources there has been new exploration drilling and exploration activity in the region of interest, the significance of which can not be considered by a review of dated, possibly out-dated, conventional or non-conventional assessments of petroleum potential. The timeframe for delivery of this report precluded the collection or consideration of new data, or a detailed reinterpretation of existing data. What is presented is a summary of the "state-of-the-art".

## *RESERVES, RESOURCES AND POTENTIAL*

The terms *resource*, *reserve* and *potential*, as defined previously (Podruski et al., 1988) and widely accepted (National Energy Board, 2003; Canadian Gas Potential Committee, 2001; 1997), are used in this study. *Resource* is all petroleum accumulations known or inferred to exist, without economic or technological burdens. The uncertainties between the conventional and non-conventional resources are captured in their description. Conventional resources are described in marketable volumes and non-conventional resources are described as raw gas in-place. *Reserves* are discovered resources and *potential* describes undiscovered resources. A *pool* is defined as a petroleum accumulation, typically within a hydrodynamically separate reservoir rock interval. Pools within a geographic region comprise a *field*. A *play* consists of pools or prospects that share a common geological history and petroleum system.

This discussion below describes the setting, discovery and assessment of conventional and non-conventional (gas hydrate) petroleum resources in the Mackenzie Delta-Beaufort Sea petroleum province. The regional geology, basin analysis and exploration history datasets constrain total petroleum resource estimates (Majorowicz and Osadetz, 2001, Dixon et al., 1995; Dixon et al., 1994). The report highlights differing perceptions of both the reserve and resource as inferred by different stakeholder groups. Resolving these differences is beyond the scope of this study, but they are important, if the impacts on resources are to be correctly assessed.

Gas hydrates were identified in the early stages of exploration for petroleum, but they were initially considered as a hazard to drilling for conventional resources (Bily and Dick, 1974). However, recent developments, locally and globally (Dallimore et al., in press; 1999) indicate that natural gas hydrates could contribute to the regional commercial petroleum supply within the production lifetime of the established conventional reserves. Thus, the gas hydrate resource represents petroleum potential that should be considered as part of the total petroleum endowment in the Mackenzie Delta-Beaufort Sea region. The existing characterization of the natural gas hydrate resource requires further study and constraint, as the spread in estimated volumes presented herein remains very large and may be conservative (Majorowicz and Osadetz, 2001, Smith and Judge, 1995). There is, at present, no consensus or method regarding what proportion of the natural gas hydrate resource is recoverable, either technologically or economically.

## *REGIONAL GEOLOGICAL SETTING*

The BMB is a rifted continental margin prograded by a major river delta. The assessed Canadian BMB extends from the head of Mackenzie Delta to the southern permanent ice pack limit in Beaufort Sea between 127° to 141°W (Figure 2), although potential may occur to the continental slope edge. About one third of the region lies onshore with the rest underlying Beaufort Sea.

### Stratigraphy

BMB stratigraphy is divided into regional tectono-stratigraphic sequences separated by regional unconformities (Figure 3; Dixon et al., 1995; Dixon et al., 1994). These are:

- Proterozoic Inuvikian sequence
- Cambrian to Devonian Franklinian sequence

- Mississippian to upper Hauterivian Ellesmerian sequence
- Upper Hauterivian to Present Brookian sequence

Proterozoic Inuvikian sequence is attributed no petroleum potential (Wielens, 1992). It links correlative successions in Interior Platform (Williams, 1986; Young et al., 1979) and the Arctic Islands (Campbell and Cecile, 1981). These low-grade metamorphic rocks form a poorly known thrust faulted succession 13 to 15 km thick. Cambrian to Devonian Franklinian sequence records Paleozoic crustal extension, adjacent the Paleo-Pacific passive margin, prior to late Paleozoic Ellesmerian orogeny (Morrow, 1999; Norris, 1997). This succession, carbonates and shales with lesser evaporites and sandstones, extends under Tuktoyaktuk Peninsula and Beaufort Sea. Black, radioactive Upper Devonian Canol Fm. potential petroleum source rocks at the base of the Imperial clastic wedge overlie the carbonates.

Carboniferous to middle Hauterivian Ellesmerian sequence consists of three successions. Carboniferous successions record Ellesmerian orogenic history (Lane, 1998). Permian, Triassic and Jurassic strata record the interval between Ellesmerian orogeny and the formation of Canada ocean basin. Permian Sadlerochit Group disconformably overlies Carboniferous strata and is correlative with a thicker Permian succession under the southwestern Mackenzie Delta (Norris, 1997). Triassic strata correlative with Shublik Fm. in Alaska occur in the British Mountains. The Jurassic to Hauterivian succession is composed of cratonically derived, northwestward prograding clastic wedges that pass northwest and west into shales (ibid.).

Upper Hauterivian to Present Brookian sequence unconformably overlies older successions in, and on the margin of, Canada Basin (Lane, 1998; 1997; Dixon, 1995). It is subdivided by a significant unconformity between Upper Cretaceous and underlying strata. Boundary Creek and Smoking Hills strata overlying this unconformity are petroleum source rocks. The Late Cretaceous to Holocene succession is 12 to 14 km thick (Dietrich et al., 1985). Individually up to 4 km thick, the deltaic sequences consist of thick interbedded sandstone and shale at the basin margins that pass into shales basinward. Isolated sandstone-rich intervals occur on the shelf. The identified sequences are (Figure 3):

- Boundary Creek: Cenomanian-Turonian;
- Smoking Hills: Santonian-Campanian;
- Fish River: late Maastrichtian-Paleocene (contains Tent Island Fm. and sandstone member of Moose Channel Fm.);
- Reindeer supersequence: Aklak sequence (late Paleocene-early Eocene)
- Reindeer supersequence: Taglu sequence (early-?Middle Eocene);
- Richards: middle-late Eocene;
- Kugmallit: Oligocene
- Mackenzie Bay: Oligocene-Miocene;
- Akpak: Miocene;
- Iperk: Plio-Pleistocene;
- Shallow Bay: late Pleistocene-Holocene.

Fish River and Aklak sequences were deposited in western Beaufort Sea where they form a large sandstone-rich belt. Eocene depocentres occur farther east. Taglu strata occur under Richards Island and vicinity, while Kugmallit strata underlie the central Beaufort shelf. Mackenzie Bay and Akpak depocentres are not yet identified. A major drop in relative sea level during the late Eocene exposed the shelf resulting in submarine canyons in the slope and shelf and a large submarine fan in basal Kugmallit sequence. Much of the Kugmallit sequence was transported directly into deep water resulting in a thick, muddy Oligocene succession on the central Beaufort shelf. The Iperk depocentre is located beneath eastern Beaufort Sea shelf and Holocene deposition occurs in central Beaufort Sea.

**Structural setting**

The area can be divided into four structural domains (Figure 4):

- Stable Craton.
- Southeast Margin of Canada Basin
- Cordilleran Fold Belt, and
- Canada Basin

The Stable Craton underlies regions east of Peel River and south of Tuktoyaktuk Peninsula, where Paleozoic and Mesozoic strata overlie a thick Proterozoic succession (Norris, 1997). The westward thickening Paleozoic stratal wedge more deformed progressively westward, while the thin Mesozoic succession in the same region is gently folded. The faulted southeast Canada Basin margin under Tuktoyaktuk Peninsula bounds the Stable Craton with large, growth faults extending northeastward offshore, on which most displacement is associated with Mesozoic rifting during formation and opening of Canada Basin (Lane, 1998). Highly deformed Cordilleran Fold Belt strata extend into western Beaufort Sea. Compressional and strike-slip structures formed during late Cretaceous and early Tertiary deformation are superimposed on older tectonic elements - all of which originated as fault-bounded structures (Lane, 1998).

Canada Basin is underlain by oceanic and transitional crust covered by sedimentary successions below the Beaufort shelf (Lane, 1998; 1997; Dixon, 1995; Dixon et al., 1994). Lower Tertiary strata in western Beaufort Sea are deformed in an arcuate fold belt that dissipates northeastward and basinward. In the nearshore, asymmetric basin-verging folds are commonly cut by steep reverse faults on the oceanward limb. Deeper in the basin folds are more symmetrical and less faulted. Stratal thinning in fold limbs indicates folding during deposition. In the central Beaufort, under Richards Island and in nearshore areas, folds are cut by younger listric normal faults that shallow basinward, although large hinterland-facing normal faults occur in the Tarsiut area. The prominent Tarsiut-Amauligak Fault Zone, basinward of which the sedimentary succession is essentially unfaulted, extends from Tarsiut, northeastward through the Ukalerk area, (Dixon, 1995). Thick, little deformed, Plio-Pleistocene Iperk sequence unconformably overlies structures in underlying Tertiary and older strata. West of Mackenzie Delta are large structures, including Blow River High and Herschel High anticlinoria. Adjacent to southern Herschel High is Demarcation Sub-basin, a synclinorium filled with middle Eocene and younger strata.

## REGIONAL PETROLEUM GEOLOGY

The BMB is prospective for petroleum. 263 wells, including 4 gas hydrate research wells, (Figure 2) and much publicly available seismic reflection data, plus onshore studies are the basis for the prevailing geological interpretations and the exploration play concepts (Majorowicz and Osadetz, 2001; Dixon et al., 1994). The only data not considered in this report is that held confidential under Indian and Northern Affairs (INAC) / National Energy Board (NEB) petroleum regulations.

In 1962 favorable geological characteristics led to the Texcan Nicholson G-56 and N-45 wells on the Beaufort Sea coast (wells 1 and 2, Table 1 and Figure 2, shown subsequently as, well X*). Atkinson Point oil discovery (well 12*; 6.74 X $10^6m^3$ recoverable crude oil (RCO), NEB, 1998), in 1969, and Taglu gas discovery (58.62 X $10^9m^3$ marketable natural gas (MNG) well 27*; well 29in Figure 5, shown subsequently as, well X#) in 1971, near Mallik L-38 (well 35*; conventional reserve, 745.94 X $10^6m^3$ MNG (NEB, 1998)), led to an exploratory effort that moved offshore in 1973 with Imperial Immerk B-48 (well 70*) and Adgo F-28 (well 78*; well 25#; 3.20 X $10^9m^3$ MNG and 6.2 X $10^6m^3$ RCO (NEB, 1998)) on artificial islands. In 1976, drilling from ice-strengthened drill ships accessed deeper waters. Prior to 1998 exploration resulted in 252 wells including 150 new field wildcat wells (Table 1, Please note: Figure 2 indicates *wells* drilled in the BMB and the *well numbers* for that figure are given in Table 1; Figure 5 indicates *major petroleum discoveries* in the BMB and the *discovered petroleum accumulation numbers* for that figure are given in the second (tabular) part of Figure 5.).

Oil was the primary target during the 1970s to mid-1980's. Beginning in 1992 industry activity was suspended due to transportation problems and low commodity prices. The Ikhil gas field (well 29*) was developed, 1998-99, to supply Inuvik. Increased natural gas prices and planned pipeline construction revived exploration in 1999. New exploration leasing and intensive 3D seismic surveying has led to seven wells since 2002, including the North Langley K-30 gas discovery (well 263*; Nickles, 2003). Several companies envisage a gas pipeline by 2009 with production from the 163.4 X $10^9m^3$ MNG reserve at Taglu (well 27*; well 29#), Niglintgak (well 55*; well 30#) and Parsons Lake (well 33*; well 43#) (Imperial Oil et al 2003). Nearby resources, like Mallik (well 35*), are also likely to be developed.

Exploration identified non-conventional gas hydrate resources (Dallimore et al., 1999; Weaver and Stewart, 1982; Bily and Dick, 1974). Initially gas hydrates were a drilling hazard in the pursuit of deeper prospects. The 1971 Mallik L-38 well (well 35*) was drilled on a northwest trending, fault-bounded anticline. Drill-stem tests over gas hydrates at Mallik L-38 (1104-1107 m and 924-927 m) and Ivik J-26 (1017-1020 m and 1006-1009 m, well 38*; well 32#; conventional reserve, 945.10 X $10^3m^3$ RCO (NEB, 1998)) recovered methane (Bily and Dick, 1974). Cuttings, mud-log gas analysis and logs indicated gas hydrates in Beaufort Sea (Weaver and Stewart, 1982;), at Niglingtak and in permafrost at Taglu (Collett and Dallimore, 1997). Gas hydrate was cored at Taglu (Dallimore and Collett, 1995) and deliberate gas hydrate studies occurred in 1998 at the JAPEX /JNOC/GSC Mallik 2L-38 research well (Dallimore et al., 1999; well 251*). A broader research consortium drilled three wells in 2002 (Mallik 3L, 4L and 5L; wells 255, 256 and 257*; Dallimore et al., in press).

## *CONVENTIONAL PETROLEUM DISCOVERIES*

Exploration discovered 52 conventional oil and gas fields with an expected 172.75 X $10^6m^3$ RCO and condensate and an expected 254.67 X $10^9m^3$ MNG (NEB, 1998; Table 2; Appendix 2, Figure 5.). These discoveries remain undeveloped, with the exception of Ikhil. Discovery rights are continued under 65 significant discovery and 2 production licenses (INAC, 2003). Many other wells encountered petroleum indications and there are petroleum shows significant discoveries that are not attributed reserves. Petroleum occurs in Paleozoic carbonates, Lower Cretaceous sandstones and Tertiary sandstones. Most discoveries occur in upper Brookian sequence, with smaller finds lower Brookian, Ellesmerian and Franklinian sequences.

Pools in Paleozoic and Lower Cretaceous reservoirs occur in the southern Mackenzie Delta and along Tuktoyaktuk Peninsula. Discoveries in Tertiary reservoirs are concentrated in the central BMB. Exploration in the relatively unexplored western Beaufort Sea (e.g. Adlartok P-09 oil discovery, 17.89 X $10^6m^3$ RCO) indicates significant petroleum potential. Three accumulations occur in carbonate reservoirs: Mayogiak J-17 (652.51 X $10^3m^3$ RCO), West Atkinson L-17 (973.04 X $10^3m^3$ RCO), and Unak L-28 (1.04 X $10^9m^3$ MNG). Petroleum is trapped in Lower Cretaceous sandstones throughout Tuktoyaktuk Peninsula and southern Mackenzie Delta adjacent to Kugmallit Trough oil "kitchen". Oil occurs at Kugpik 0-13 (634.05 X $10^3m^3$ RCO), Kamik D-48 (182.15 X $10^3m^3$ RCO) and Imnak J-29 (1.65 X $10^6m^3$ RCO). Large gas accumulations occur in Parsons Group at the Parsons gas fields (35.46 X $10^9m^3$ MNG; 1.88 X $10^6m^3$ recoverable condensate). Gas was recovered from Rat River strata at Unak L-28 (1.04 X $10^9m^3$ MNG).

Most petroleum discoveries in Beaufort Sea and adjacent Mackenzie Delta occur in Tertiary strata. Petroleum occurs in Fish River, Aklak, Taglu, Kugmallit and Mackenzie Bay sequences. Taglu and Kugmallit sequences account for most reserves, while smaller reserves occur in Kugmallit sequence. There is a general trend for BMB accumulations to be more oil-prone basinward. Tertiary succession organic matter is predominantly Type III, terrestrial and natural gas-prone. While this explains the natural gas, other organic matter types are contributing the oils (Snowdon, 1995; Brooks, 1986; Snowdon and Powell, 1979).

### ***PETROLEUM SYSTEMS***

Continental margin deltaic complexes are major and prolific petroleum provinces globally (Ekweozor and Daukoru, 1994; Morse, 1994; Demaison and Huizinga, 1991), primarily because of the ubiquitous availability of petroleum source rocks within deltaic petroleum systems, especially since Tertiary time. Petroleum source rocks are commonly poorly characterized in major deltaic settings, primarily because the progradation of shallower-water facies, the primary reservoirs, facilitates the migration of petroleum from source rocks in deeper-water facies, but at the same time the progradation buries petroleum sources below the common depth of wells drilled to test the reservoirs. This makes the recovery of samples for geochemical characterization more difficult in deltaic settings. Source rock potential depends on the total amount of organic carbon and organic matter, regardless of source richness, although rich source *may* have greater secondary migration potential than lean sources.

The identified organic matter in the Tertiary succession is predominantly Type III, terrestrial and natural gas-prone. While this may explain the source of much of the natural gas, it is clear that other organic matter types are contributing the oil reserves and resources (Snowdon, 1995). Oil-source rock compositional correlations indicate that the liquid petroleum is probably derived from two primary possible Tertiary sources. Crude oils from the central Beaufort area have a composition that links them to basal Richards shale. In other discoveries, such as Adlartok P-09, in the west Beaufort, the unique compositional trait of the Richards shale is absent indicating a second effective petroleum system, possibly in Paleocene shales. In addition there may also be other sources for the oils including resinite, or tree resin-rich, organic matter, which is also known to generate oil at lower thermal maturities (Snowdon and Powell, 1979). The petroleum systems compositions and correlations is currently being reviewed and revised.

Compositional data from natural gas and gas hydrates points to a thermogenic petroleum source (Lorenson et al., 1999). This indicates the petroleum in gas hydrates is migrating, leaking, from the underlying conventional accumulations, such that the gas hydrate petroleum system requires a connexion to the conventional petroleum system to ensure the development of thick, high saturation accumulations. Therefore the gas hydrate resource potential may be limited more by source, migration pathway and timing than by physical stability conditions. Although no indication for bacterially generated methane, which is common for deep marine gas hydrate settings (Lorensen et al., 1999), has been described from Beaufort Sea it is reasonable to assume that similar biological processes operate in Beaufort Sea as on the Pacific and other oceanic margins. Therefore other sources of methane and other modes of gas hydrate occurrence may yet be found in Beaufort Sea.

The area has a very low thermal maturity gradient. Wells drilled to 4500 m, in the Tertiary succession in the central Beaufort area generally encounter thermally immature or marginally mature sediments at total depth (Snowdon, 1995). Vitrinite reflectance values (a petrographic measure of thermal maturity) rarely reach the beginning of the main stage of crude oil generation (0.7% VR) even at the bottom of deep wells, although the west Beaufort Natsek and Edlok wells encountered the main stage of crude oil generation (0.8% VR) in Paleocene strata. Below the Yukon coastal plain the Blow River E-47 well encountered very high thermal maturity (2.0% VR – overmature dry gas zone) in Albian strata near the surface.

### *CONVENTIONAL RESERVES*

Deltas are major petroleum provinces (Ekweozor and Daukoru, 1994; Morse, 1994; Demaison and Huizinga, 1991). There is a lack of consensus regarding the BMB discovered reserve (Table 2). Dixon et al. (1994) inferred the conventional resource from the conventional petroleum reserve (Table 3). The NEB (1998) re-evaluated reserves to be 172.75 X $10^6m^3$ RCO plus condensate and 254.67 X $10^9m^3$ MNG. These estimates result from sufficiently different field definitions that they are not directly comparable (Table 3); however the reserve estimates used by Dixon et al. (1994) are like the $P_{0.05}$ reserve estimate produced by the NEB (1998). The Canadian Association of Petroleum Producers (CAPP) defines the discovered reserves as between 64.95 X $10^6m^3$ (CAPP, 1986) to 53.95. X $10^6m^3$ RCO (CAPP, 2002) and zero (CAPP, 2002) to 298.73 X $10^9m^3$ (CAPP, 1993) MNG Table 2). The Canadian Gas Potential Committee (CGPC, 2001) estimates discovered conventional gas at 250 X $10^9m^3$ MNG Table 2). Variations result from interpretation and definitions.

### *UNDISCOVERED CONVENTIONAL RESOURCES*

Resource assessments incorporate objective data with expert opinion (Lee, 1999). The last estimates (Dixon et al., 1994) precede the post-1992 activity hiatus and no significant new public data is available. The Geological Survey of Canada (GSC) estimated mean undiscovered conventional petroleum resource is 856.0 X $10^6m^3$ RCO and 1,510 X $10^9m^3$ MNG (Table 2, 3). The CGPC used methods and data similar to the 1994 GSC assessment to estimate a potential of 598 X $10^9m^3$ MNG, a volume that is 602 X $10^9m^3$ smaller than their previous estimate (CGPC, 1997). Industrial sources suggest that new exploration results require upward revision of all assessments (Bergquist et al., 2003).

Twenty assessed exploration plays distinguished by geographic, geological and engineering criteria (Table 3; Figure 6) occur in four groups (Dixon et al., 1994):

- The *Onshore/ Shallow Offshore Play group* comprises eight plays in Paleozoic, Mesozoic and Tertiary successions that exist in the Richards Island, South Delta and Tuktoyaktuk Peninsula areas, as well as their extensions into the adjacent shallow offshore.
- The four plays of the *Offshore Delta Play group* form a narrow Tertiary play trend, in ~25 m of water, between Tarsiut and Amauligak fields, where several major crude oil and natural gas discoveries have been made.
- The three plays of the *West Beaufort Play group* have different target horizons, petroleum systems and structural style.
- The *Deep Water and Other Play group* comprises five plays, dominated by two deep-water clastic plays. These two Tertiary plays lie basinward of the Offshore Delta and West Beaufort play groups. This playgroup also includes three conceptual plays.

All playgroups include a marine component; such that their exploration, development and transportation will all have an impact on the marine realm. Current petroleum assessments do not attempt to distribute the undiscovered potential within the play regions (c.f. Chen et al., 2002; 2000), rather it is necessary to consider the potential as a characteristic of the play area or play-group region, without knowledge of where the undiscovered resources are most likely to occur within the play boundary. Methods for the spatial description of undiscovered petroleum resources are in development, but their application to this region will have to follow.

The *Onshore/Shallow Offshore* includes 39.84 X $10^6m^3$ in 14 discovered oil fields (Dixon et al., 1994). Adgo, Kumak, Ivik North and Atkinson are the largest discovered oil pools. An undiscovered 166.67 X $10^6m^3$ remains in ~150 pools. One pool >15.87 X $10^6m^3$ and 14 pools >3.97 X $10^6m^3$ are inferred undiscovered. The expected total oil resource is 206.51 X $10^6m^3$ of which 117.14 X $10^6m^3$ will occur in the discovered and 15 largest undiscovered pools. About 214.45 X $10^9m^3$ gas is discovered in 14 fields, including Taglu, Parsons and Niglintgak (Dixon et al., 1994). More than 356.94 X $10^9m^3$ gas remains undiscovered in >170 pools (ibid.). Another gas field >28.33 X $10^9m^3$, comparable to Taglu or Parsons, is predicted to be undiscovered.

The *Offshore Delta* success rate is ~50%. The total oil potential in this playgroup is, 342.85 X $10^6m^3$. The giant Amauligak oil discovery (37.346 X $10^6m^3$ NEB, 1998; Appendix2) dominates the 144.4 X $10^6m^3$ discovered oil reserve (Dixon et al., 1994). Seven discovered fields comprise 42% of the total oil endowment. The undiscovered oil potential, 198.41 X $10^6m^3$, is concentrated in large pools, including four undiscovered pools >15.87 X $10^6m^3$. Most playgroup oil discoveries have associated natural gas. The total gas endowment is 359.49 X $10^9m^3$; including 120 undiscovered pools containing 266.29 X $10^9m^3$. Most of the expected undiscovered gas is expected in pools >2.83 X $10^9m^3$. In addition to Amauligak, an undiscovered gas pool, >28.33 X $10^9m^3$ is predicted. Twenty-eight model pools between 28.33-2.83 X $10^9m^3$ are expected to contain twice the potential of that occurring in the two model pools >28.33 X $10^9m^3$.

The *West Beaufort* is the least explored. It is estimated to contain, 342.22 X $10^6 m^3$ oil. Adlartok (17.89 X $10^6 m^3$), a major oil discovery, is the second largest oil field in the BMB. In addition, three more pools >15.87 X $10^6 m^3$ are predicted, which combined with 12 predicted undiscovered pools in the 3.97 to 15.87 X $10^6 m^3$ size range suggests that the 16 largest pools will contain between 190.48 and 349.21 X $10^6 m^3$ oil (Dixon et al., 1994, p. 3). West Beaufort Play group natural gas potential has not been assessed, but it should not be discounted.

The large Kopanoar oil and Kenalooak natural gas discoveries occur in the *Deep Water and Other* play group, where four plays are untested concepts. The five deep-water plays are expected to contain total discovered and undiscovered endowment of 240.80 X $10^6 m^3$ oil and 557.51 X $10^9 m^3$ natural gas, but they could potentially hold undiscovered resources of 341.27 X $10^6 m^3$ oil (Dixon et al., 1994, Figure 55, p. 41) and >546.74 X $10^9 m^3$ natural gas (Dixon et al., 1994, Figure 56, p. 41).

## ***TOTAL REGIONAL CONVENTIONAL PETROLEUM ENDOWMENT***

The BMB conventional endowment (Dixon et al., 1994) can be compared to the revised discovered volumes (NEB, 1998). The total oil endowment is between 984.13 X $10^6 m^3$ and 1.24 X $10^9 m^3$ RCO (75 to 25% probability) with a mean of 1.13 X $10^9 m^3$ of which 172.75 X $10^6 m^3$ (NEB, 1998) or ~15%, is discovered. An undiscovered potential of 811.38 X $10^6 m^3$ to 1.07 X $10^9 m^3$ RCO is inferred, if the NEB 1998 reserve value is used. Between 1.63 X $10^{12} m^3$ and 2.07 X $10^{12} m^3$ MNG is inferred (75 to 25% probability), with a total expected endowment of 1.84 X $10^{12} m^3$ MNG. Approximately 254.67 X $10^9 m^3$ MNG, or approximately 14% is discovered. The undiscovered potential is 1.24 X $10^{12} m^3$ to 1.68 X $10^{12} m^3$ MNG, although much larger potentials are indicated at lower probabilities. The region has an expected undiscovered 957.2 X $10^6 m^3$ recoverable crude oil and 1.64 X $10^{12} m^3$ recoverable conventional natural gas, if the total revised expected reserve (NEB, 1998) is subtracted from the expected total potential (Dixon et al., 1994). No gas assessment exists for plays in the *West Beaufort Play group* region (Dixon et al., 1994) where the second largest oil field, Adlartok P-09 (NEB, 1998) occurs. New industrial data analysis throughout the basin points toward a need to comprehensively revise the estimates of total resource endowment, both by revising existing plays and by considering new conceptual plays not previously assessed (Bergquist et al., 2003).

Within the petroleum province there are areas that are likely to be the focus of renewed exploration efforts, based on their potential and accessibility. The most immediate interest occurs in the Onshore/Shallow Offshore, Offshore Delta and West Beaufort regions. It is possible to distinguish a resource of immediate interest that includes an oil potential of ~888.89 X $10^6 m^3$ and a natural gas potential of ~934.84 X $10^9 m^3$. Within the resource endowment of immediate interest it is possible to consider only oil pools >3.97 X $10^6 m^3$ and natural gas pools >2.83 X $10^9 m^3$. These large pools comprise 698.41 X $10^6 m^3$ RCO in 50 pools, of which 525.66 X $10^6 m^3$ remain undiscovered, and 793.20 X $10^9 m^3$ MNG in 65 pools, of which 538.53 X $10^9 m^3$ remains undiscovered, if the NEB reserve volume are used. These larger pools could probably be developed economically.

### *REGIONAL NON-CONVENTIONAL GAS HYDRATE RESOURCES*

Gas hydrates are present onshore and offshore in Kugmalit, Mackenzie Bay, and Iperk sequences (Dallimore et al., 1999; Figure 3). Natural gas hydrates are crystalline substances consisting of water and natural gas that remain stable under conditions of relatively cold temperatures and high pressures. Knowledge of the geothermal gradient allows the region of gas hydrate stability to be predicted as a function of depth, which is a proxy for pressure, under the overlying rock and the composition of the natural gas, which also affects gas hydrate stability and structure. Gas hydrates represent a vast potential hydrocarbon resource that may substantially impact Canada's future domestic energy supply and speed a shift towards more environmentally friendly hydrocarbon sources. The carbon emitted from natural gas is 58% of that which would be released from coal, and 68% of that which would be released from crude oil required to generate a similar amount of energy. The innovative formation of a leading Canadian technology for the development of gas hydrate resources is aligned to Canada's innovation strategy, its maintenance of global competitiveness and its fulfillment of international commitments on global climate change. An engineering and technological model – analogous to the Tar Sands and *in situ* Bitumen developments – applied to gas hydrate resources, has the promise of maintaining Canadian global competitiveness, while developing the economies of coastal, aboriginal and northern communities.

Compositional data from gas hydrates points to a thermogenic petroleum source (Lorenson et al., 1999) indicating that the petroleum in gas hydrates has migrated from underlying conventional accumulations. Consequently gas hydrate distribution may be biased if accumulations occur with a systematic relationship to conventional pools. Conservatively, hydrates occur in 29% of BMB wells (Majorowicz and Osadetz, 2001, although different studies of gas hydrate infer different occurrences, e.g. Smith 2001; Figure 7). Direct indications are few (Dallimore et al., 1999) and inferences of occurrence may be biased (Smith, 2001; Majorowicz and Osadetz, 2001; Dallimore and Collett, 1999; Smith and Judge, 1995; 1993). Commonly gas hydrates are detected using wireline logs. Other indicators include mud gasification and drill-stem and production tests. Drilling procedures can obscure detection. Wells stabilized with "casing" in the interval below the permafrost expose gas hydrates to degradation by fluid circulation prior to logging (Brent et al., in press; 2003). The geothermal field knowledge is limited and few data over a vast area makes it difficult to map hydrate occurrence. This led Majorowicz and Osadetz (2001) to infer the natural gas hydrate stability area and thickness assuming:

- Structure I (methane) hydrate,
- Temperatures at the base the water column or permafrost
- A geothermal gradient from well data, and
- Hydrostatic pressure.

This inferred natural gas hydrate thickness is 82 m on average (Figure 8). The inferred natural gas hydrate stability area is ~125,000 km$^2$ (Figure 9) and the stability zone is commonly more than 200 m. The gas hydrate resource is discounted for non-occurrence rates observed in wells. In permafrost regions the inferred stability zone is consistently between 200-500 m thick where the permafrost is 100 to 900 metres thick, thus, the inferred hydrate layer tends to occur 700 to 1200 m deep. This is greater than in shallow marine settings, and areas of thin (<100 m) or absent permafrost, where stability is complicated by glacial history and/or recent marine transgression.

The gas hydrate natural gas resource is inferred using a discounted volume method that considers stability zone volume, reservoir porosity, hydrate saturation and a gas volume expansion factor. The gas hydrate resource is estimated to be between 2.4 X $10^{12}$ and 87 X $10^{12}m^3$ raw natural gas in place (Majorowicz and Osadetz, 2001; CGPC, 2001). This is greater than the 88 X $10^9m^3$ inferred by Davidson et al., (1978), but it captures the 1.60 X $10^{13}m^3$ estimated by Smith and Judge (1995). Higher volumes could be expected if Structure II hydrate was present, as inferred elsewhere where the gas is thermogenic (Majorowicz and Osadetz, 2001). Some gas hydrates occur at depths deeper than that predicted by the available geothermal data, possibly due to the quality of the subsurface temperature data set or petroleum composition.

The data sets used to assess gas hydrate accumulations were generally collected in the course of other activities, primarily conventional petroleum exploration. As a result, the data set of all investigators suffers from numerous deficiencies attributable to the age, location and type. For example, conventional petroleum exploration during the 1960’s to 1990’s resulted in 4111 geophysical logging curves being recorded in 263 wells, although the depths pertinent to gas hydrates were either not logged, or the quality of the logs is poor. Only 146 wells contribute data useful to the inference of gas hydrate occurrence and characteristics. This can be augmented by seismic velocity studies from 142 wells, which also indicate gas hydrate occurrences, some of which are not detected by well logs, due to formation damage (Brent et al., in press). However existing gas hydrate assessments have been based on the analysis of wells, which may be adversely affected by formation damage from drilling activities, and they have not made use of the seismic data set. Well location criteria for conventional petroleum exploration has not tested regions that could determine if gas hydrate occurs “off-structure” nor have engineering practices always preserved evidence for gas hydrates (Brent et al., in press; 2003). Therefore gas hydrate occurrence and gas saturation are both obscured and incomplete and the historical data set is biased with respect to both occurrence and richness. More recent gas hydrate specific research provides superior characterization in local regions (Dallimore et al., 1999).

## DISCUSSION

Abundant petroleum resources make the BMB an attractive petroleum province. Renewed industry exploration has revived development prospects. Transportation to southern markets is projected to commence later this decade, building from 34 X $10^6m^3$/day to 53.8 X $10^6m^3$/day by the middle of the next decade (Imperial Oil et al., 2003). For comparison, Canada’s current natural gas production is ~453.2 X $10^6m^3$/day. By 2025 the BMB could contribute 10% or 18% of national supply (NEB, 2003) when production from Western Canada Sedimentary Basin (WCSB) may have declined to <50% of current rates.

The BMB is *“emerging as a major source for the future supply of North American energy demands”* (Bergquist et al., 2003). Industrial sources indicate a need to update resource estimates. *“A complete reanalysis of geochemical data illustrates the overall richness of the BMB’s hydrocarbon system and supports a greatly expanded range of prospectivity. This combination of new exploration data, new and significant play types, cost effective operational innovations, a developing infrastructure and growing North American gas demand have established the BMB as an important and emerging petroleum province”* (ibid.).

The expected decline in conventional natural gas production from the WCSB cannot be replaced by conventional production from Frontier regions alone. Therefore new petroleum supply from non-conventional resources like gas hydrates is required. Japan intends to establish commercial production from gas hydrates within the time frame of conventional natural gas production from Mackenzie Delta (Yonezawa, 2003). Gas hydrate production experiments (Dallimore et al., in press) provide encouragement for possible commercial production. If even a fraction of the hydrate resource becomes commercial it is highly significant for the sustainable development of Canada's arctic. Gas hydrates should be treated as a realizable resource and gas hydrate development should be planned in conjunction with conventional production.

## ***PETROLEUM RESOURCE ENDOWMENT OF THE PROPOSED MARINE PROTECTED AREA***

The proposed MPA covers 1792 sq kilometres extending from the high water mark to 5m water depth in three separate regions within BMB. The western region includes parts of Mackenzie Bay (i.e. Shallow Bay, Figure 1). The central region lies offshore of Kendall Island (Figure 1). The eastern region occurs in Kugmallit Bay (Figure 1). In total the three regions, Mackenzie Bay, Kendall Island and Kugmallit Bay, as they will be referred to below, include approximately one quarter of the Beaufort Sea shoreline around the fringes of the Mackenzie Delta. The Mackenzie Bay, Kendall Island and Kugmallit Bay regions overlie a variety of geological settings, structural features and petroleum assessment play group areas.

### Mackenzie Bay Region

The Mackenzie Bay region covers 1,160 km$^2$ and it occurs exclusively within the West Beaufort playgroup area, where it occupies approximately 20% of the playgroup area. Much of the Mackenzie Bay region is underlain, in part, by the Blow River High, a major anticlinorium of deformed Cretaceous and Tertiary strata that formed in Late Cretaceous and Tertiary time accompanying the deformation of a 5-10 km thick Albian (Lower Cretaceous) flysch succession that was deposited in the larger Blow River Trough (Lane 1998, his Figure 6), and which extends into the Blow River high. As such the Blow River High is, in part, an inversion structure, where a previous trough, filled with a thick sedimentary succession, is now an anticlinorium. The Mackenzie Bay region lies entirely within the *West Beaufort* play group, which is one of the least explored, most prospective and inadequately assessed regions of the Beaufort Sea and adjacent onshore. Portions of the proposed MPA are underlain by parts of the Adlartok and Herschel (Blow River) plays, which have been assessed (Dixon et al., 1994).

There has been no drilling in the Mackenzie Bay region and so no discoveries have been made within the proposed MPA in this region. However, discoveries have been made in portions of the play group both deeper offshore and onshore such that the size and importance of the undiscovered and untested resource attributed to the Mackenzie Bay region could be indicated by the reserves and resources in other portions of the *West Beaufort* play group region. It is also essential to note that the 1994 GSC assessment considered neither natural gas potential through the region of the West Beaufort playgroup, nor did it consider any petroleum potential in the Cretaceous succession that is known to underlie the assessed Tertiary strata. Therefore the indicated petroleum potential for both the West Beaufort playgroup and the Mackenzie Bay region of the proposed MPA must be considered a volumetrically conservative and stratigraphically inadequate assessment of the conventional petroleum potential.

The *West Beaufort* playgroup contains SDL42, wherein the Adlartok P-09 well made a major oil discovery (17.89 X $10^6 m^3$), accompanied by natural gas "shows" in 1985. Adlartok is the second largest oil field discovered in the BMB. The *West Beaufort* play group region also contains SDL52 where the Kingark J-54 well discovered both natural gas and oil (2.56 X $10^6 m^3$ (16 X $10^6$ barrels) recoverable crude oil and 1.28 X $10^9 m^3$ marketable natural gas (45 Bcf)) and a major new onshore gas discovery, the Chevron et al. Langley K-30 in EL 404, the results of which are still confidential (well #263*). Exploration Licenses 420, 404 and 417 abut, overlap or are close to the eastern margin of the Mackenzie Bay region. The 1994 assessment estimated that the *West Beaufort* playgroup contains 342.22 X $10^6 m^3$ oil. In addition, three more pools >15.87 X $10^6 m^3$ are predicted, which combined with 12 predicted undiscovered pools in the 3.97 to 15.87 X $10^6 m^3$ size range suggests that the 16 largest pools will contain between 190.48 and 349.21 X $10^6 m^3$ oil (Dixon et al., 1994, p. 3).

Dixon et al. (1994) did not assess West Beaufort playgroup natural gas potential (see note in Table 3). However, the gas resources should not be underestimated or discounted. Natural gas is present in the Kingark J-54, Adlartok P-09 and the Fort Langely K-30 wells, all of which occur within this playgroup. The proportion of the assessed undiscovered oil and the size of the undiscovered conventional natural gas resource in the West Beaufort Play group portion of the MPA cannot be currently identified more specifically. However, it is likely that promising exploration trends identified by *West Beaufort* playgroup discoveries extend into the Mackenzie Bay region. In addition, the existing conventional petroleum assessment does not consider the petroleum potential of any of the sub-Tertiary succession, which should also be prospective.

The Canadian Gas Potential Committee's 2001 natural gas assessment differs significantly from the GSC 1994 assessment, specifically as it puts the Mackenzie Bay region into their "Basin Margin Zone – M101" play (CGPC, 2001) which is defined operationally rather than as a reflection of geological characteristics and potential. The Basin Margin Zone – M101 play is, for the largest part, geographically similar to the Onshore/Shallow Offshore Play group area (Dixon et al., 1994). The CGPC 2001 study is, however, neither appropriate, nor helpful with respect to inferring the undiscovered potential of the proposed Mackenzie Bay MPA region.

The lack of drilling and exploration in the Mackenzie Bay area makes it difficult to determine the gas hydrate thickness in the region, especially since the boundary conditions associated with the discharge of water from the Mackenzie River may have reduced gas hydrate formation in portions of the proposed MPA. However, there are very few wells in the region of Mackenzie River discharge and the area of affected gas hydrate stability is uncertain (see Figure 7). Furthermore, some of the regions inferred not to have gas hydrates using wire-line well logs (e.g. Smith, 2001) have indications, from vertical seismic profiles and seismic check-shot data, for gas hydrates (Brent et al., 2004). Therefore, the inferred average thickness of gas hydrate accumulations within the Mackenzie Bay region is estimated, from nearby wells, to be approximately 24 metres, over 1,160 $km^2$; of Mackenzie Bay. Assuming average rates of occurrence and reservoir characteristics based on previous work (Majorowicz and Osadetz, 2001) the Mackenzie Bay region gas hydrate resource is estimated to be between 6.68 X $10^9 m^3$ – 2.42 X $10^{11} m^3$ raw natural gas in place.

### Kugmallit Bay Region

The Kugmallit Bay region covers 363 $km^2$ and lies entirely within the Onshore/Shallow Offshore Play group area, where it covers slightly less than 10% of the offshore portion of the playgroup area. Exploration has not been permitted in the region underlying Kugmallit Bay. As a result no wells have been drilled and no discoveries have been made. The Kugmallit Bay region lies entirely or partially within the regions of the Taglu and Ivik plays areas that were explicitly assessed for conventional petroleum potential (Dixon et al., 1994). The potential of Kugmallit Bay remains untested. However, Kugmallit Bay is underlain by deeply down-faulted successions that include major petroleum source rocks and it is commonly referred to as the Kugmallit Bay "oil kitchen".

Hansen G-07 (SDL45), discovered in 1986, lies close to the northern tip of the proposed MPA. This discovery contains 0.68 15.87 X $10^6m^3$ crude oil and 4.59 X $10^9m^3$ gas (7.17 X $10^9m^3$ gas at P-05). Seven new exploration licenses (ELs 384, 385, 418 and 420) almost surround the proposed MPA and these are being actively explored. New exploration licenses ELs384 and 385 are exclusively onshore, due to the withholding of exploratory rights in the Kugmallit Bay offshore.

The *Onshore/Shallow Offshore* includes 39.84 X $10^6m^3$ in 14 discovered oil fields (Dixon et al., 1994). Adgo, Kumak, Ivik North and Atkinson are the largest discovered oil pools. An undiscovered 166.67 X $10^6m^3$ remains in ~150 pools. One pool >15.87 X $10^6m^3$ and 14 pools >3.97 X $10^6m^3$ are inferred undiscovered. The expected total oil resource is 206.51 X $10^6m^3$ of which 117.14 X $10^6m^3$ will occur in the discovered and 15 largest undiscovered pools. About 214.45 X $10^9m^3$ gas is discovered in 14 fields, including Taglu, Parsons and Niglintgak (Dixon et al., 1994). More than 356.94 X $10^9m^3$ gas remains undiscovered in >170 pools (ibid.). Another gas field >28.33 X $10^9m^3$, comparable to Taglu or Parsons, is undiscovered. This play group is clearly one of the most prospective in the BMB, and it is likely that regions under Kugmallit Bay will be among the most prospective regions that remain to be explored, since the bay is generally coincident with the main region of petroleum generation and it is inferred to be the location where most of the oil in the *Onshore/Shallow Offshore* play group was generated. The proportion of the assessed undiscovered oil and conventional natural gas resource occurs within the Kugmallit Bay region cannot currently be identified more precisely. However, petroleum play trends identified in those areas open to exploration, both onshore and offshore, extend into regions beneath Kugmallit Bay.

The lack of drilling in Kugmallit Bay makes it difficult to determine the gas hydrate thickness. However, nearby wells commonly indicate gas hydrates. The inferred average gas hydrate thickness within the Kugmallit Bay region is estimated from, nearby wells to be approximately 42.5 meters, over 363 $km^2$ in Kugmallit Bay. Assuming average rates of occurrence and reservoir characteristics based on previous work (Majorowicz and Osadetz, 2001) the amount of gas hydrate resource within the Kugmallit Bay region is estimated to be between 3.70 X $10^9m^3$ – 1.34 X $10^{11}m^3$ raw natural gas in place.

### Kendall Island Region

The Kendall Island region covers 193 $km^2$ offshore Kendall Island and occurs predominantly in the Onshore/Shallow Offshore Play group area, where it comprises slightly less than 10% of the offshore portion of the play group area. The Kendall Island region also impinges on a small portion of the Offshore Delta Play group area. Exploration license EL407 surrounds the Kendall Island portion of the proposed MPA. Recently there has been seismic exploration in EL407 where at least one well is expected to be drilled by August 2005. ELs 393, 404 and 420 also cover extensive areas of coastal waters in the vicinity of the Kendall Island portion of the proposed MPA.

One significant discovery, Pelly B-25, a 2.96 X $10^9 m^3$ MNG discovery in SDL028, which has an area of 1809 ha, lies almost entirely within the Kendall Island region of the proposed MPA. The Pelly B-25 discovery lies in one of the most prospective petroleum fairways within the BMB. The very large Taglu field is 20 km to the southeast and the very large Niglintgak field lies 25 km to the south. Both Taglu and Niglintgak are anchor fields for the first round of conventional petroleum development. The Pelly B-25 well was not optimally located with respect to the prospect it tests, in part because of changes in the velocity structure of the permafrost, and the Pelly B-25 gas accumulation could be enlarged both in volume and geographic extent if additional wells were drilled. SDLs 15 & 25 occur adjacent to the southern margin of Kendall Island region of the proposed MPA where the Garry North G-07 has an expected 0.28 X $10^9 m^3$ MNG. The Adgo F-28 discovery of 3.23 X $10^9 m^3$ MNG and 6.19 X $10^6 m^3$ RCO occurs adjacent the western margin of the Kendall Island region in SDL 050. Eight additional discoveries lie farther offshore the Kendall Island region. Similar prospects are likely to occur in the Kendall Island region, all within the immediate vicinity of the existing discoveries with high expectations that they contain significant petroleum volumes.

The *Onshore/Shallow Offshore* includes 39.84 X $10^6 m^3$ and an undiscovered 166.67 X $10^6 m^3$ in ~150 pools, as discussed above. One pool >15.87 X $10^6 m^3$ and 14 pools >3.97 X $10^6 m^3$ are inferred undiscovered and the expected total oil resource is 206.51 X $10^6 m^3$ of which 117.14 X $10^6 m^3$ will occur in the discovered and 15 largest undiscovered pools. About 214.45 X $10^9 m^3$ gas, and more than 356.94 X $10^9 m^3$ gas remains undiscovered in >170 pools (ibid.). Another gas field comparable to Taglu or Parsons, is undiscovered. The proportion of the assessed undiscovered oil and conventional natural gas resource in the *Onshore/Shallow Offshore* occurs within the Kendall Island region of the proposed MPA cannot currently be identified more specifically.

The little drilling and exploration in the Kendall Island area makes it difficult to determine the gas hydrate thickness in the region. However, nearby wells commonly are inferred to indicate gas hydrates, including some of the thickest and richest gas hydrate accumulations in the world, such as, at the Mallik site. The inferred average thickness of gas hydrate accumulations within the Kendall Island region of the proposed MPA is estimated to be approximately 50 metres, within an area offshore Kendall Island of 193 $km^2$. Assuming average rates of occurrence and reservoir characteristics based on previous work (Majorowicz and Osadetz, 2001) the gas hydrate resource within the Kendall Island region is estimated to be between 2.32 X $10^9 m^3$ – 8.40 X $10^{10} m^3$ raw natural gas in place.

**Aggregate Petroleum Potential In the Proposed MPA**

The three proposed MPA regions comprise about 1.37% of the BMB area. The proposed MPA regions are essentially lacking petroleum exploration activities, internally. Two of these areas, Mackenzie Bay and Kugmallit Bay, have not had exploratory licenses issued nor have they been drilled to establish even rudimentary petroleum potential. Still the adjacent regions and geological trends underlying the MPA regions have produced significant discoveries. Likewise, the region offshore Kendall Island contains and abuts significant conventional and non-conventional petroleum discoveries. Therefore the indications for petroleum potential within the proposed MPA must be inferred from data available from wells drill geographically nearby, or on geological trend, but generally outside of the proposed MPA.

Significant conventional and non-conventional discoveries occur geographically adjacent to, or on geological trend, with all three of the proposed MPA regions. All three regions are within geological trends, or petroleum play "fairways" and petroleum generation "kitchens" that are among the most attractive potential geological settings. This has been confirmed by recent onshore conventional and non-convention exploratory drilling as indicated by the still confidential Fort Langley natural gas discovery (well #263*). The shoreline proximity of petroleum resources in the proposed MPA, as is the general case, enhances their economic viability, due to lower transportation and construction costs and this increases the probability of their development once production begins from the anchor fields, Taglu, Parsons Lake and Niglingtak, in the region.

The proposed MPA occur within portions of the *Onshore/ Shallow Offshore and West Beaufort playgroups.* Therefore the maximum conventional petroleum potential can be expected to be a fraction of the total petroleum in those two playgroups alone. Since only the Pelly B-25 discovery, a 2.96 X $10^9 m^3$ MNG gas discovery in SDL028, lies effectively within the boundaries of the proposed MPA, the gas undiscovered potential of the proposed MPA, can be inferred to be additionally restricted to be the sum of that discovered gas and a portion of the undiscovered potential in two play groups. The Kendall Island and Kugmallit Bay regions both lie effectively within the *Onshore/ Shallow Offshore play group* such that some undetermined portion of the more than 356.94 X $10^9 m^3$ undiscovered gas, including possibly a gas field >28.33 X $10^9 m^3$ (i.e. comparable to Taglu or Parsons) could occur with the MPA. However it is not possible to infer the total undiscovered conventional natural gas potential in the proposed MPA because there is no assessment of undiscovered gas potential in the West Beaufort play group, and no basis for inferring the gas potential of the largest region, Mackenzie Bay, of the proposed MPA. The total undiscovered crude oil potential in the *Onshore/ Shallow Offshore and West Beaufort playgroups* is 466 X $10^6 m^3$ recoverable, some undetermined portion of which occurs within the proposed MPA. In the Kendall Island and Kugmallit Bay regions that might include one undiscovered pool >16 X $10^6 m^3$ and multiple undiscovered pools >4.0 X $10^6 m^3$. In the Mackenzie Bay region the undiscovered oil potential could include one to three crude oil pools >16 X $10^6 m^3$ and some number of the 12 undiscovered pools in the 3.97 to 15.87 X $10^6 m^3$ size range.

The specific undiscovered conventional petroleum resource in the proposed MPA cannot be predicted more accurately, due to the nature of the available conventional petroleum appraisal because there is no natural gas assessment of the *West Beaufort play group* (see note in Table 3). It is not possible to consider the specific impact of restricted geographic withdrawals on the petroleum resource, because the resource assessment methods employed were not geographically specific. For example, the onshore/shallow offshore playgroup is geologically diverse and structurally complicated. It constitutes very attractive onshore and shallow offshore exploration prospects, such that part of the discovered reserves and undiscovered resources of this play group may occur inside and outside the proposed boundaries of the proposed MPA, although it is not possible to allot which proportion of the undiscovered resource may occur with the proposed boundaries of the candidate MPA's. In addition the discrete nature of petroleum pools and their natural variations in relative magnitude prevent a pro-rated allotment as a fraction of the area affected.

Based on the information supplied some portions of the Proposed Marine Protected areas abut, impinge on or include significant discovery licenses. Likewise some of the Proposed Marine Protected areas may overlap with potential transportation routes for offshore discoveries to onshore transportation facilities. Therefore it is also impossible, using the current formulation of the reserves and resources to determine which resources outside of the proposed boundaries of the candidate MPA's might be affected or impacted by their designation.

Methods of geographically based and spatially distributed resource assessments are being developed with funding from the federal government's Panel for Energy Research and Development, POL 1.2.1: Offshore Environmental Factors for Regulatory, Design, Safety and Economic in the project entitled "Mapping the Geographic Distribution of Undiscovered Petroleum Potential in Canada." That project has developed several methods for geographically distributing petroleum potential spatially (Chen et al., 2002; 2000; Gao et al., 2000). These methods could be applied to the existing exploratory petroleum data set, as a separate and significant undertaking, with the result being a direct knowledge of the impact of the areas identified in the proposed boundaries of the candidate MPA's.

Using data from nearby wells the total gas hydrate potential in the three regions of the proposed MPA, combined, is estimated to be between 1.27 X $10^{10}m^3$ – 4.60 X $10^{11}m^3$ raw natural gas in place, where the total BMB gas hydrates potential is estimated to be between 0.24 - 8.7 x $10^{13}$ $m^3$. The area of the three regions of the proposed MPA comprises about 1.37% of the gas hydrates stability domain, but it is inferred to contain only about 0.5% of the gas hydrate resource, primarily because the expected thickness of gas hydrates is significantly lower in the Mackenzie Bay area, where warmer seafloor temperatures have persisted due to the discharge of the Mackenzie River.

The amount of natural gas resource in natural gas hydrates underlying the regions of the proposed MPA estimated here should be used cautiously, for two reasons. First, the region of the MPA is essentially untested by drilling and all of the characteristics inferred for the MPA regions need to be inferred from nearest points of control. This probably tends to overestimate the gas hydrate resource since the applicability of data from terrestrial wells to marine settings introduces some uncertainty, particularly in the region affected by the main discharge from the Mackenzie River. Second, there are other data that suggest the occurrence of gas hydrates might be universally underestimated due to formation damage (Brent et al., in press; see above).

## CONCLUSIONS

The BMB petroleum endowment consists of 52 discovered fields. The total oil endowment is between 984.13 X $10^6m^3$ and 1.24 X $10^9m^3$ RCO (75 to 25% probability) with a mean of 1.13 X $10^9m^3$ of which 172.75 X $10^6m^3$, or ~15%, is discovered. An undiscovered oil potential of 811.38 X $10^6m^3$ to 1.07 X $10^9m^3$ RCO is inferred. Between 1.63 X $10^{12}m^3$ and 2.07 X $10^{12}m^3$ MNG is inferred (75 to 25% probability), with a total expected endowment of 1.90 X $10^{12}m^3$ MNG. Approximately 254.67 X $10^9m^3$ MNG, or approximately 13% is discovered. The undiscovered conventional natural gas potential is 1.24 X $10^{12}m^3$ to 1.68 X $10^{12}m^3$ MNG. The region has an expected undiscovered 957.2 X $10^6m^3$ recoverable crude oil and 1.64 X $10^{12}m^3$

recoverable conventional natural gas. No gas assessment exists for plays in the playgroup region (Dixon et al., 1994) where the second largest oil field, Adlartok P-09 (NEB, 1998), occurs and new industrial data analysis points toward a need to comprehensively revise the potential upward (Bergquist et al., 2003). The conventional resources are co-located with an immense gas hydrate resource estimated between 2.4 X $10^{12}$ to 87 X $10^{12}m^3$ raw natural gas in place. Current engineering and economic models that allow the determination of a supply from gas hydrate as a function of price are lacking.

The undiscovered gas in the Kendall Island and Kugmallit Bay regions of the proposed MPA is a portion of 356.94 X $10^9m^3$ undiscovered gas, including possibly a gas field >28.33 X $10^9m^3$ MNG gas plus the discovered gas at Pelly B-25, 2.96 X $10^9m^3$. The inference of the total gas potential in the proposed MPA is not possible because there is no assessment of undiscovered gas potential in the West Beaufort play group, and therefore there is no basis for inferring the gas potential of the Mackenzie Bay region of the proposed MPA. The total undiscovered crude oil potential in proposed MPA is some fraction of 466 X $10^6m^3$ recoverable crude oil that might include one undiscovered pool >16 X $10^6m^3$ and multiple undiscovered pools >4.0 X $10^6m^3$ in the Kendall Island and Kugmallit Bay regions and one to three crude oil pools >16 X $10^6m^3$ and some fraction of the 12 undiscovered pools in the 3.97 to 15.87 X $10^6m^3$ size range in the Mackenzie Bay region. Within the region of the MPA the total gas hydrate potential is estimated to be between 1.27 X $10^{10}m^3$ - 4.60 X $10^{11}m^3$ raw natural gas in place. The gas hydrate resource is not well constrained. The gas hydrate resources are estimated using data gathered during exploration for deep conventional resources, which generally treated gas hydrates as a drilling hazard, and which, as a result, may have negatively biased indications for gas hydrates in wells.

The specific impact and effect of three candidate Marine Protected Area (MPA) sites identified in the southern Canadian Beaufort Sea on the exploration, development and transportation of existing regional petroleum reserves and resources cannot be appropriately determined using the available sources of data and inference. There is no consensus regarding either the discovered reserve or the undiscovered potential among various stakeholder groups, based on the pre-2002 data set alone. Since 2002 much important new, confidential industrial data not considered in these estimates has been acquired. Since, the proven conventional petroleum reserves indicate that the Mackenzie Delta-Beaufort Sea has a potential to be a prolific producer of conventional natural gas and light oil, probably towards the end of this decade, it is recommended that a detailed and comprehensive revision and review of existing and new data be undertaken to re-evaluate the conventional and non-conventional petroleum potential of this region.

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Table 1: Schedule of wells in the Beaufort-Mackenzie Basin.

Table 2: Petroleum Endowment Estimates by Source and Type

| Source | Discovered Crude Oil | Expected Undiscovered Crude Oil | Discovered Natural Gas | Expected Undiscovered Natural Gas |
|---|---|---|---|---|
| Conventional Crude Oil and Natural Gas Reserves and Resources | | | | |
| National Energy Board (1998); (values given as 0.95, *mean*, and 0.05 probabilities) | (91.8, 172.75, 277.3) X $10^6 m^3$ recoverable crude oil and condensate | N/A | (186.2, 254.7, 349.3) X $10^9 m^3$ marketable natural gas | N/A |
| GSC Conventional Resources (Dixon et al., 1994) | 276.8 X $10^6 m^3$ (1.744 X $10^9$ bbls) recoverable | 855.6 X $10^6 m^3$ (5.39 X $10^9$ bbls) recoverable | 332.6 X $10^9 m^3$ (11.74 X $10^{12}$ cubic feet) recoverable | 1,509.9 X $10^9 m^3$ (53.3 X $10^{12}$ cubic feet) recoverable |
| Canadian Association of Petroleum Producers Conventional Resources (Various) | 64.95 X $10^6$ $m^3$ to 53.95. X $10^6$ $m^3$ established | N/A | 298.73 X $10^9$ $m^3$ to zero marketable | N/A |
| Canadian Gas Potential Committee Conventional Resources (2001) | N/A | N/A | 250 X $10^9 m^3$ (8.84 X $10^{12}$ cubic feet) marketable | 598 X $10^9 m^3$ (21.105 X $10^{12}$ cubic feet) marketable |
| Non-Conventional Gas Hydrate Resources | | | | |
| GSC Non-Conventional Natural gas Hydrate Resources (Majorowicz and Osadetz, 2001) | N/A | N/A | N/A | 2,400 X$10^9$ to 87,000 X$10^9$ $m^3$ raw in-place |
| Canadian Gas Potential Committee Non-Conventional Natural gas Hydrate Resources (2001) | N/A | N/A | N/A | 2,400 X$10^9$ to 87,000 X$10^9$ $m^3$ raw in-place |
| | | | | |

Table 3: Expected Discovered and Undiscovered Petroleum Endowment by Play-group

| | Crude Oil (mean recoverable). | | Natural Gas (mean recoverable) | |
|---|---|---|---|---|
| Play-group | Discovered | Undiscovered | Discovered | Undiscovered |
| | | | | |
| Onshore/Shallow Offshore | 39.84 X $10^6$ $m^3$ (0.251 X $10^9$ bbls) | 166.67 X $10^6$ $m^3$ (1.05 X $10^9$ bbls) | 214.45 X $10^9$ $m^3$ (7.57 Tcf) | 356.94 X $10^9$ $m^3$ (12.5 Tcf) |
| Offshore Mackenzie Delta | 144.4 X $10^6$ $m^3$ (0.910 X $10^9$ bbls) | 198.41X $10^6$ $m^3$ (1.25 X $10^9$ bbls) | 93.20 X $10^9$ $m^3$ (3.29 Tcf) | 266.29 X $10^9$ $m^3$ (9.4 Tcf) |
| West Beaufort Sea | 35.87 X $10^6$ $m^3$ (0.226 X $10^9$ bbls) | 306.35X $10^6$ $m^3$ (1.93 X $10^9$ bbls) | No discoveries public prior to 1994 | No assessment of potential reported in Dixon et al., 1994; however, Table 1, p. 43 contains a value of 354.11 X $10^9$ $m^3$ (12.5 Tcf) |
| Deep Water and Other | 56.67 X $10^6$ $m^3$ (0.357 X $10^9$ bbls) | 184.13 X $10^6$ $m^3$ (1.16 X $10^9$ bbls) | 24.93 X $10^9$ $m^3$ (0.88 Tcf) | 532.58 X $10^9$ $m^3$ (18.8 Tcf) |
| Total (Dixon et al., 1994) | 276.83 X $10^6$ $m^3$ (1.744 X $10^9$ bbls) | 855.56 X $10^6$ $m^3$ (5.39 X $10^9$ bbls) | 332.58 X $10^9$ $m^3$ (11.74 Tcf) | 1.51 X $10^{12}$ $m^3$ (53.3 Tcf) |
| Total (mean discovered, NEB, 1998; undiscovered CGPC, 2001) | 172.75 X $10^6 m^3$ (1.16 X $10^9$ bbls) | No other estimate available | 254.7 X $10^9 m^3$ (8.99 Tcf) | 598 X $10^9 m^3$ (21.105 Tcf) |
| Difference (%) | 66% | N/A | 77% | 40% |

## FIGURE CAPTIONS

Figure 1. Index Map of the areas of interest for the candidate Marine Protected Area (MPA) sites identified by the Department of Fisheries and Oceans (DFO) in the southern Canadian Beaufort Sea (see Terms of Reference in Appendix 1). The three regions of the proposed Marine Protected Area are shaded orange.

Figure 2. Index map of wells drilled in the Mackenzie Delta and Beaufort Sea Region. The key for well names appears in Table 1 (modified after Indian and Northern Affairs Canada, 2003).

Figure 3. Stratigraphic column for the Mackenzie Delta and Beaufort Sea Region, indicating the main petroleum resource intervals (after Dixon et al., 1994).

Figure 4. Major Structural Elements of the Mackenzie Delta and Beaufort Sea Region (after Dixon et al., 1994). The approximate boundaries of the three regions of the proposed Marine Protected Area (Figure 1) are shaded yellow.

Figure 5. a) Map indicating significant conventional petroleum discoveries in the Mackenzie Delta and Beaufort Sea Region, keyed to b) a description of the size of the discoveries made within the significant conventional petroleum pools discovered (after Dixon et al., 1994). The approximate boundaries of the three regions of the proposed Marine Protected Area (Figure 1) are shaded yellow.

Figure 6. The extent of conventional petroleum playgroups analyzed by Dixon et al. (1994). The approximate boundaries of the three regions of the proposed Marine Protected Area (Figure 1) are shaded yellow.

Figure 7. Probable gas hydrate occurrences inferred from well logs in the Mackenzie Delta Beaufort Sea (modified after Smith, 2001). The pink region shows the consensus area where most gas hydrate studies agree that gas hydrates occur within their stability zone. The yellow region shows the area where gas hydrate occurrence is not well known due to a lack of drilling, but where nearby wells suggest that gas hydrate occurrence is expected to average 24 metres.

Figure 8. Histograms illustrating the thickness of gas hydrate zones inferred from wells in, the Mackenzie Delta Beaufort Sea, for map area shown in Figure 9.

Figure 9. Calculated depth of the base of the methane hydrate stability zone in the Mackenzie Delta-Beaufort Sea region, after Judge and Majorowicz (1992).

## APPENDIX 1: TERMS OF REFERENCE FOR THIS REPORT

## APPENDIX 2: BMB CONVENTIONAL PETROLEUM RESERVES (FROM NEB, 1998)