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Canada

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Permanent link: https://doi.org/10.4095/311219

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**Recommended citation**
Dietrich, J.R., Chen, Z., Hannigan, P.K., Hu, K., and Xu, Y., 2018. Oil and gas resource potential in the deep-water Canada Basin, Arctic Ocean; Geological Survey of Canada, Open File 8355 (revised), 31 p. https://doi.org/10.4095/311219

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## TABLE OF CONTENTS

## ABSTRACT

The Canada Basin is a deep-water basin adjacent to the Arctic continental shelves of northwest Canada and northern Alaska. Perennial ice cover in the Arctic Ocean has historically prevented detailed geologic study of the basin. Recent seismic surveys (2007 to 2011) provide substantial new information on crustal architecture and sediment fill of the basin. These geophysical data provide a framework for a regional study of basin petroleum geology and resource potential. This report presents the first assessment of oil and gas potential in the Canada Basin.

Conventional petroleum resources in Canada Basin were evaluated with a volumetric play-based assessment method and an independent basin-scale global analogue method. The volumetric play assessment included quantitative analyses of four petroleum plays in Cenozoic strata. Mean estimates of total recoverable resource potential in Canada Basin are 779 million $m^3$ (4.9 billion barrels) oil, 659 billion $m^3$ (23 Tcf) free gas, and 308 billion $m^3$ (10.8 Tcf) solution gas. The total recoverable energy resource potential (oil and gas combined) is estimated at 1683 million $m^3$ (10.5 billion barrels) oil equivalent. The independent assessment based on the global analogue methodology provides mean estimates of total recoverable potential of 11 billion barrels oil equivalent, similar to the volumetric play estimates.

Natural gas hydrates may be a significant unconventional petroleum resource in Canada Basin, but an assessment of recoverable gas volumes was not possible with available data.

This assessment study provides important new insights into the natural resource endowment of the Arctic Canada Basin, a region with currently unresolved international jurisdiction issues.

## INTRODUCTION

The Geological Survey of Canada has prepared petroleum resource assessments of numerous offshore and frontier sedimentary basins across Canada. This report presents the first evaluation of oil and gas potential in the deep-water Canada Basin, north and west of the Arctic margins of northern Canada and the United States. The assessment study, part of the GSC Geoscience for New Energy Supply Program, included reviews of published and unpublished geological and geophysical data and reports, interpretations from seismic reflection data, and modelling of thermal maturation histories. Two assessment approaches were utilised to derive quantitative resource estimates, a volumetric probability method and a global analogue basin-yield method.

Canada Basin is a deep-water sedimentary basin beneath the continental slope, rise and abyssal plain of the Arctic Ocean, encompassing a total area of about 1 million $km^2$. Water depths in abyssal plain parts of the basin are up to 3850 m (Figure 1). The basin is bordered to the east by the Arctic Islands continental shelf and to the south by the Canadian and U.S. Beaufort Sea shelf. The submarine Northwind and Alpha-Mendeleev basement ridges form the western and northern basin margins.

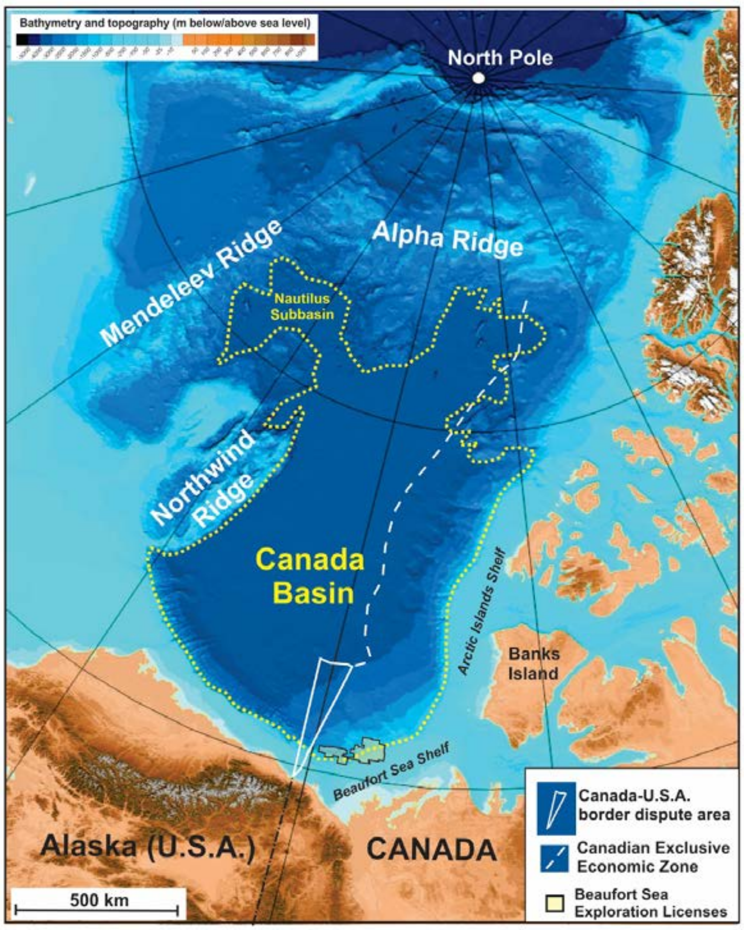



**Figure 1.** Map of the deep-water Arctic Canada Basin and surrounding physiographic elements (bathymetric map adapted from IBCAO; Jakobsson et al., 2012). Offshore jurisdictional issues include the border dispute area between Canada and the United States in the Beaufort Sea continental shelf and southern Canada Basin, and the unresolved divisions for the Arctic Ocean region under negotiation under the auspices of the United Nations Convention on the Law of the Sea. The Canadian exclusive economic zone extends to the 200 nautical mile (370 km) limit. Current (2018) Canadian Beaufort Sea petroleum exploration licenses extend into continental slope areas of the southeastern Canada Basin.

Perennial heavy ice cover has historically limited geological study and exploration in Canada Basin. There has been no petroleum exploration drilling in the basin, but forecast reductions of the Arctic sea ice may make the region a future exploration target. Several high-value petroleum exploration licenses occur along the southeastern margin of the basin (Figure 1).

Early seismic reflection surveys in continental slope areas along the southern margins of Canada Basin included about 3000 line-kilometres of data acquired by the United States Geological Survey (USGS) (Grantz et al., 1982) and the GSC (Dietrich et al., 1989). The first seismic reflection data acquired in the abyssal plain parts of the basin (about 2500 line-km) were from 1988 and 1992-93 USGS surveys (Grantz et al., 2004). Between 2007 and 2011, joint icebreaker expeditions organized by U.S. and Canada government agencies led to the acquisition of significant new geophysical data over most parts of the Canada Basin. These data included approximately 15,500 line-kilometres of reflection seismic and sonobuoy wide-angle refraction data (Chian and Lebedeva-Ivanova, 2015; Mosher et al., 2016). These geophysical data were obtained to provide a geoscience framework to determine sovereign rights over the deep seabed beyond the Exclusive Economic Zone (200 nautical mile/370 km limit), as part of a United Nations Convention on the Law of the Sea (UNCLOS) initiative. In addition to UNCLOS jurisdictional issues, the southern Canada Basin is strategically important because it encompasses a portion of a disputed boundary zone in the Exclusive Economic Zone in the Arctic Ocean north of Alaska and Canada (Figure 1). Canada claims the boundary follows the projection of the onshore Alaska/Yukon border ($141^{O}$ W) into the Arctic Ocean, while the U.S. claim is based on equidistance lines between shorelines.

**Petroleum Resource Studies**

An assessment of petroleum resource potential in the Amerasia Basin Petroleum Province, including Canada Basin, was completed in 2012 by the USGS (Houseknecht et al., 2012). That study did not assign any petroleum resource potential to Canada Basin, due to the limited amount of available data and uncertainty associated with the presence of reservoir and source rocks. A more comprehensive qualitative evaluation of Canada Basin petroleum potential was presented by Grantz and Hart (2012). Based on interpretations of seismic reflection profiles acquired in the 1980s and 1990s, they concluded the basin probably contains significant volumes of deep-marine turbidite sandstones that could form reservoirs. They also identified several types of structural and stratigraphic features that could form hydrocarbon traps.

**GSC Assessment Study**

The GSC assessment incorporated information from UNCLOS seismic data that was not available at the time of previous resource studies of the region. The UNCLOS data provide important new insights into sediment thickness, depositional facies, prospect types, and hydrocarbon indicators. Other seismic data evaluated in this study included 1960s to 1990s vintage USGS, GSC, and petroleum-industry seismic profiles in continental slope areas of the southern Canada Basin. Crustal-scale seismic data recently acquired by ION Geophysical (GX

Technology) provide insights into the deep geology of southern basin margin areas (Helwig et al, 2011). Well data from the Beaufort-Mackenzie Basin provided information on stratigraphy, reservoir quality, petroleum source rocks, and geothermal gradients (Chen et al., 2007; Hu et al., 2014, 2018). Seismic correlations from areas of well control provide information on Canada Basin stratigraphy.

## GEOLOGICAL SETTING

### Basin Development

The tectonic development of the deep-water Canada Basin and broader Amerasia Basin have been described in a number of previous studies, including recent syntheses by Grantz et al. (2011) and Hutchison et al. (2017). Canada Basin development occurred in at least six phases (Figure 2). The first phase included Jurassic (or older) to Early Cretaceous rotational extension between Eurasia and North America and creation of ocean-continent transitional crust and syn-rift basins (Grantz et al. 2011). An alternative model for early basin development included strike-slip faulting and formation of transtensional pull-apart basins (Hutchison et al., 2017). The second and third phases of basin development involved Early Cretaceous seafloor spreading and formation of oceanic crust, followed by rotational or strike-slip emplacement of the Chukchi continental block into western Canada Basin. Later phases of basin development included Late Cretaceous magmatism in northern parts of the basin (part of the emplacement of the Alpha-Mendeleev Large Igneous Province; AM-LIP), Late Cretaceous-Cenozoic deposition of thick successions of post-rift deep-marine sediments, and Cenozoic formation of a syn-tectonic foldbelt encompassing southeastern parts of the basin (Lane and Dietrich, 1995).

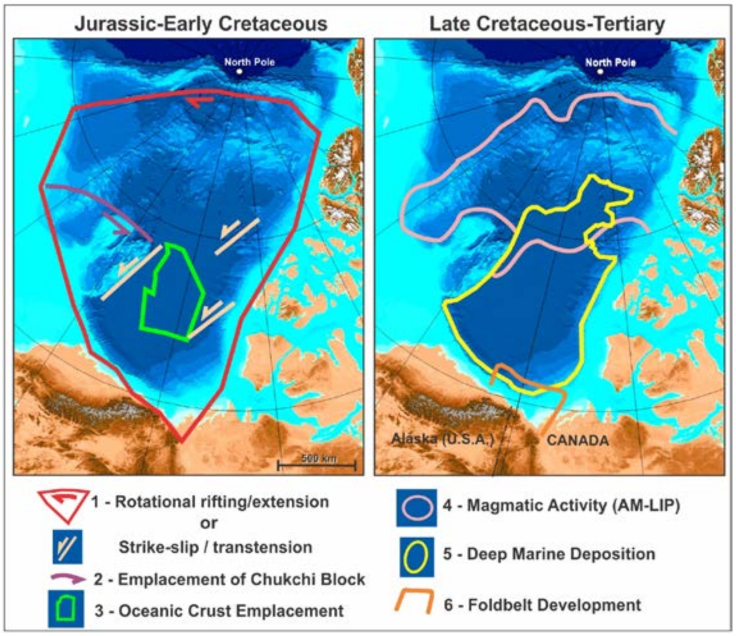



**Figure 2.** Generalized phases of Canada Basin development: 1 – Jurassic to Early Cretaceous rotational rifting between Arctic Canada and Alaska/Eurasia and formation of transitional crust and synrift basins (or alternatively, strike-slip faulting and formation of pull-apart basins); 2 – rotational emplacement of Chukchi continental block; 3 - Early Cretaceous seafloor spreading and formation of oceanic crust; 4 - Late Cretaceous magmatism associated with formation of the Alpha-Mendeleev Large Igneous Province; 5 - Late Cretaceous-Cenozoic subsidence and deposition of deep-marine sediments; 6 - Cenozoic tectonic folding.

Seismic reflection and refraction data indicate the Canada Basin contains up to 13 km of Mesozoic-Cenozoic sedimentary strata (Figure 3). Basement beneath the basin fill consists of oceanic crust in the central basin and transitional or thinned continental crust in surrounding basin areas (Mosher et al., 2012; Chian et al, 2016). The southern Canada Basin margins are interpreted to be nonvolcanic passive margins. The northeastern basin margin near Alpha Ridge is interpreted as a volcanic rifted margin with thinned and intruded continental crust (Chian et al, 2016). A regional cross-section (Figure 4) illustrates the distribution of crustal types and sedimentary fill in central Canada Basin.

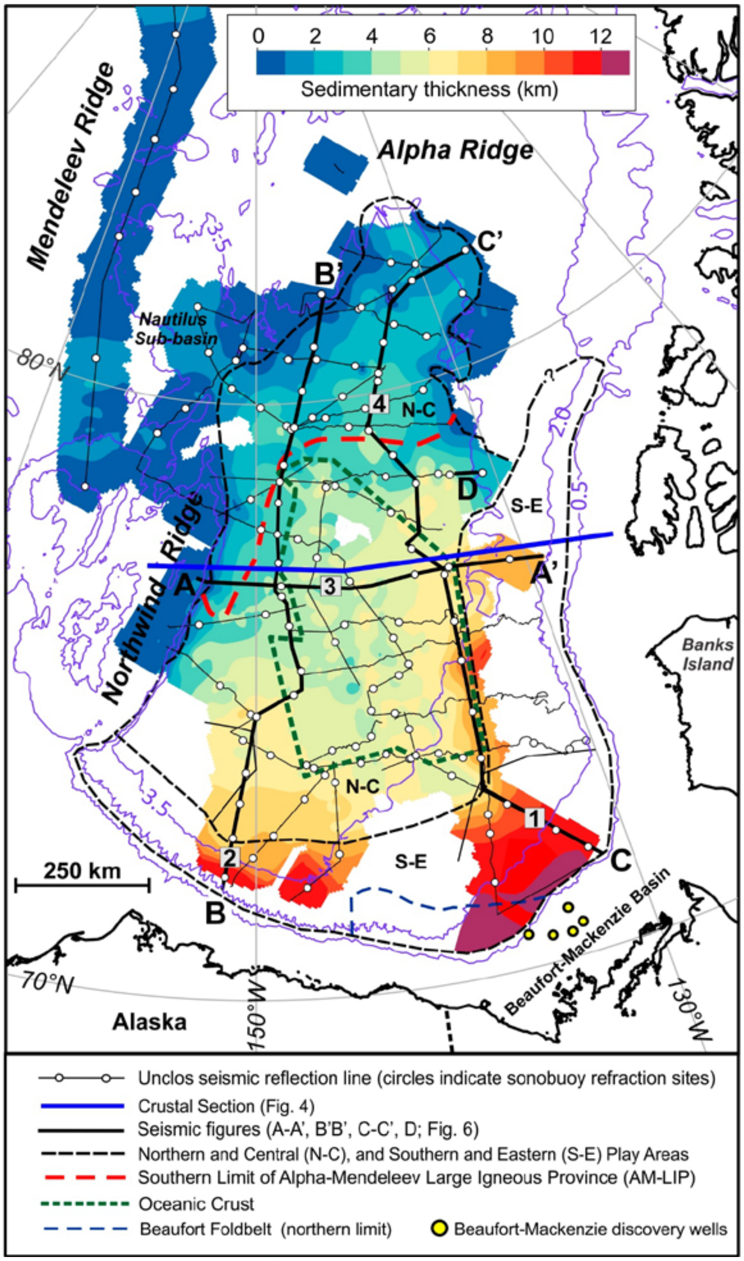



**Figure 3.** Thickness of Canada Basin sedimentary strata mapped from UNCLOS and industry seismic data (adapted from Shimeld et al., 2015; with data from Kumar et al., 2009 for the Beaufort-Mackenzie margin). Also indicated are locations of UNCLOS seismic reflection lines and refraction data sites, crustal section and illustrated seismic profiles (Figures 4, 6), assessment play areas (N-C, S-E), southern limit of AM-LIP (Saltus et al., 2011), area of oceanic crust (Chian et al., 2016), northern limit of Beaufort foldbelt, Beaufort-Mackenzie Basin wells with hydrocarbon discoveries in Cenozoic deep-marine reservoirs (Figure 9), and hydrocarbon generation models (boxes 1 to 4; Figure 10). Light blue lines are isobaths (0.5, 2.0, 3.5 km).

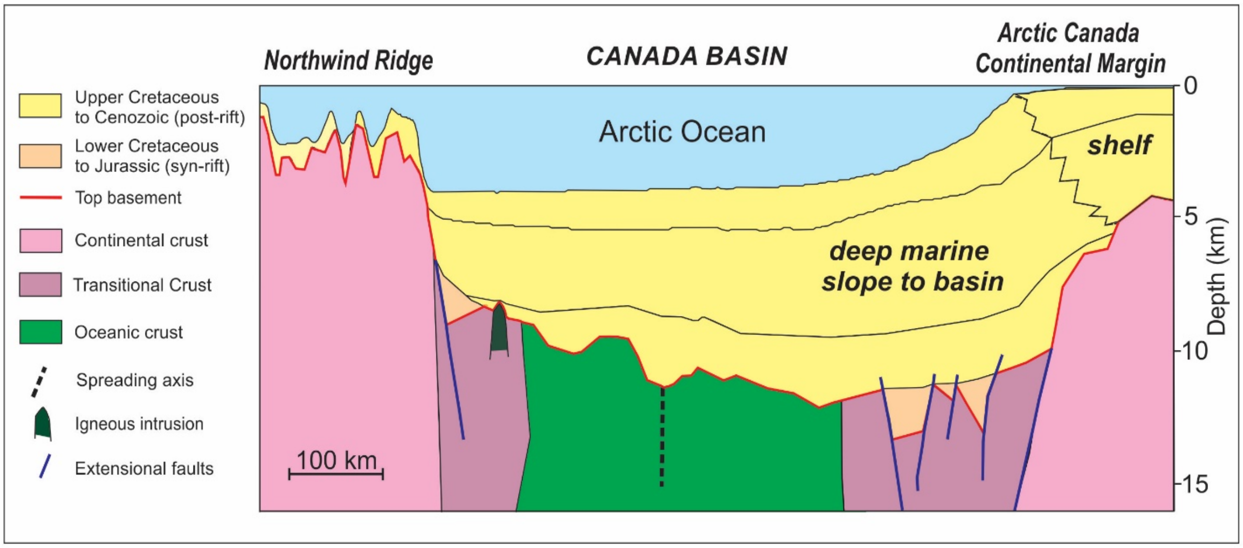
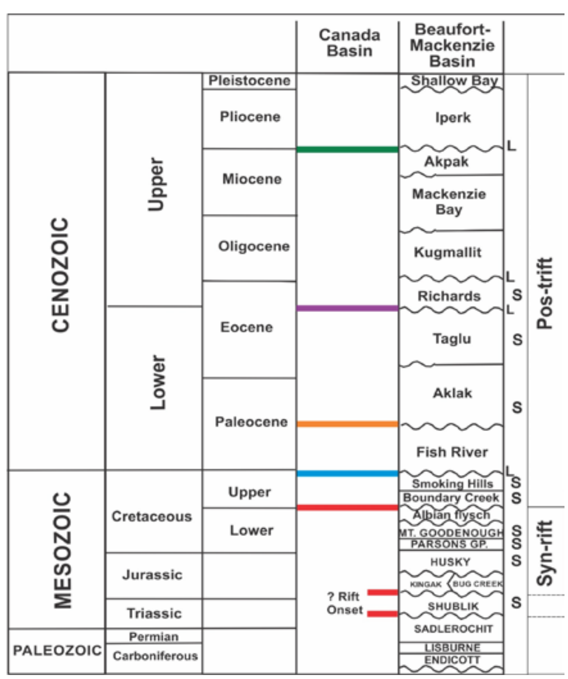



**Figure 4.** Crustal model of the central Canada Basin, from the Canadian Arctic Islands continental shelf to Northwind Ridge (location in Figure 3), delineating the main crustal zones/features and sediment distribution (modified from Oakey et al., 2013).

## Stratigraphy

The Canada Basin sedimentary section includes two main tectono-stratigraphic units; a Jurassic (or older) to Early Cretaceous syn-rift succession of mainly shallow marine sediments deposited in local extensional sub-basins, and a widespread Late Cretaceous to Pleistocene post-rift succession of mainly deep-marine turbidites and hemipelagic deposits (Figure 5).

**Figure 5.** Canada Basin and Beaufort-Mackenzie Basin stratigraphic units, sequences and formations, with indicated hydrocarbon source rock intervals (S) and major sea-level lowstands (L). Seismic-stratigraphic markers (in Figure 6) indicated by colours. Lower and Upper Cenozoic divisions refer to play stratigraphy. In most parts of Canada Basin, seismically interpreted basement correlates to the base of the post-rift section. Older syn-rift strata may locally overlie basement. The age of the oldest syn-rift strata (onset of rifting) may be Early Jurassic or Triassic.



### *Syn-rift*

In the Beaufort-Mackenzie Basin, syn-rift strata include Jurassic to Lower Cretaceous Kingak to Mount Goodenough formations and Albian Flysch. Regional studies indicate rifting may have begun in the Early Jurassic (Dixon et al., 1996; Grantz et al., 2011) or Late Triassic (Embry and Anfinson (2014). Deep syn-rift subbasins (containing 1000 to 4000 m of strata) have been interpreted in industry and USGS seismic profiles in southeastern and west-central parts of Canada Basin (Helwig et al., 2011; Grantz and Hart, 2012). UNCLOS seismic data provide only limited information on the presence of syn-rift strata, mainly in northern basin areas (Figure 6).

### *Post-rift*

Upper Cretaceous-Cenozoic post-rift strata form the bulk of the basin succession, with thick sections (10+ km) occurring adjacent to the southern and eastern basin margins. Post-rift strata thin northward and westward toward the Alpha and Northwind basement ridges. The Nautilus Subbasin, between the Northwind, Mendeleev and Alpha ridges, contains a relatively thin (<4 km) post-rift succession. In the offshore Beaufort-Mackenzie Basin, post-rift strata include numerous Late Cretaceous-Cenozoic sequences (Figure 5; Dixon et al., 1996). Regional seismic correlations and projections from the Beaufort-Mackenzie Basin provide information on Canada Basin post-rift stratigraphy (Figure 6). The lower post-rift section includes strata equivalent to the Upper Cretaceous Boundary Creek and Smoking Hills sequences and the Lower Paleocene Fish River Sequence (Figure 5). The middle post-rift section include strata equivalent to the Middle Paleocene-Lower Eocene Aklak and Taglu sequences. The upper post-rift sections include strata equivalent to the Richards, Kugmallit, Mackenzie Bay, Akpak, Iperk and Shallow Bay sequences. Several unconformities occur within the Cenozoic succession, including major unconformities of Middle Paleocene, Middle Eocene and Late Miocene age (Lane and Dietrich, 1995). Regional seismic mapping indicates shifting depositional patterns during post-rift basin development (Figure 7; Mosher et al., 2012). Upper Cretaceous-Lower Paleocene strata are thickest in southern basin areas, including a significant depocentre in the southwestern basin offshore Alaska. In contrast, Upper Paleocene to Miocene strata are thickest in eastern parts of the basin, adjacent to the Canadian Arctic Islands shelf. The youngest (Plio-Pleistocene) strata are thickest in the southeastern basin, adjacent to the eastern Beaufort-Mackenzie Basin.

Post-rift strata are commonly well imaged in UNCLOS seismic profiles (Figure 6). Most of these strata are seismically characterised by coherent, high amplitude and low amplitude reflection intervals, interpreted as turbidite and hemipelagic deposits, respectively (Grantz and Hart, 2012; Mosher et al., 2012). In southern and eastern parts of the basin, parts of the upper post-rift section contain mounded reflection intervals, often with low amplitude or chaotic internal reflections. These reflection patterns are interpreted to be images of mass transport deposits. In northern parts of the basin (within the AM-LIP), some high amplitude reflections may be associated with volcanic sills or volcaniclastic deposits (Figure 6; Lebedeva-Ivanova, 2013; Shimeld et al., 2015).

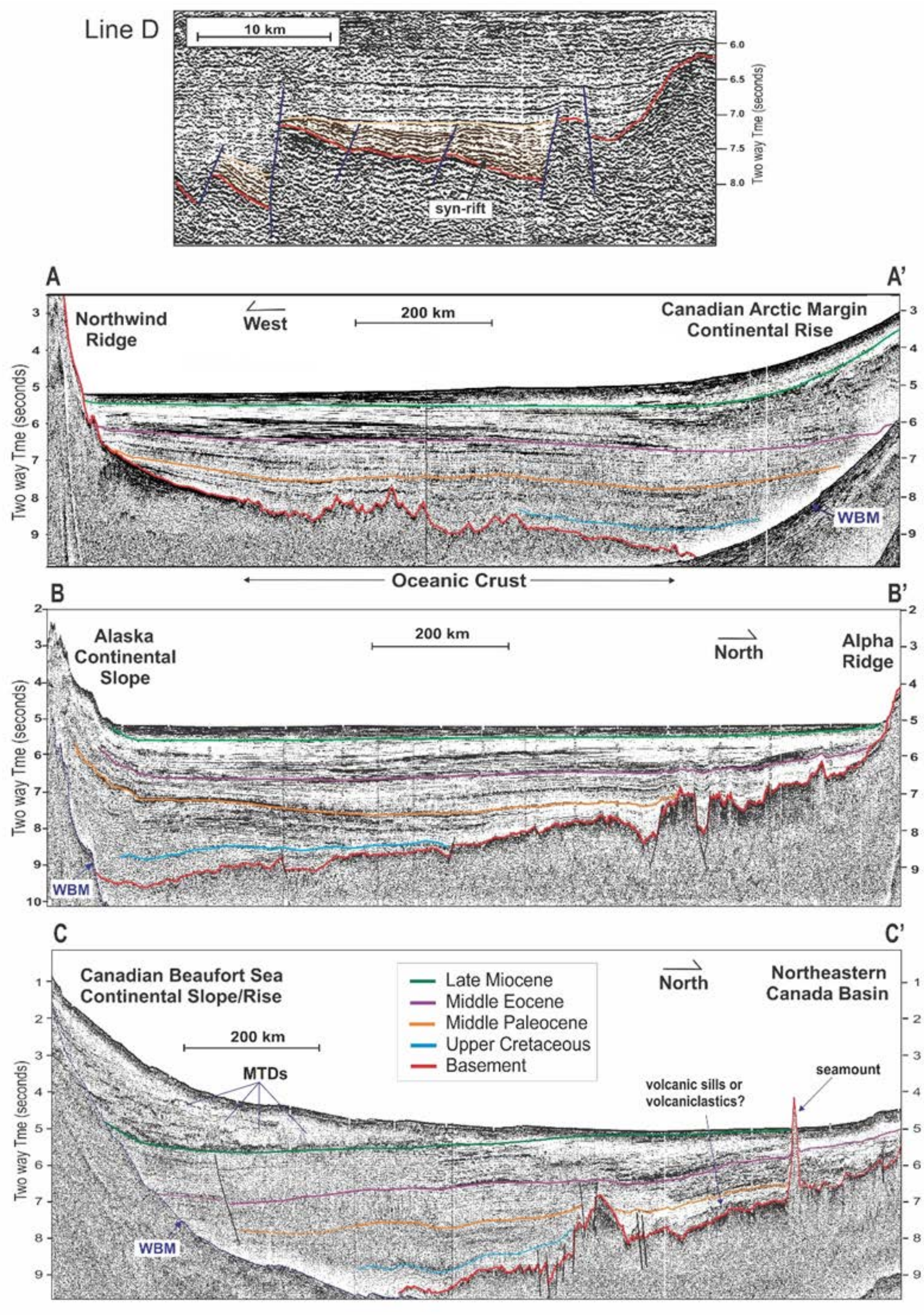



**Figure 6.** UNCLOS seismic reflection lines illustrating Canada Basin structure and stratigraphy (locations in Figure 3). Top panel (Line D) is line segment with interpreted syn-rift half-grabens. Sections A-A', B-B', C-C' are regional transects illustrating post-rift stratigraphy (stratigraphic framework in Figure 5). Water bottom multiples (WBM) obscure the deepest parts of the basin beneath the present-day continental slope and rise. Most of the post-rift section consists of hemipelagic deposits and turbidites. Hummocky or mounded reflection patterns in post-Late Miocene section indicate mass transport deposits (MTDs). Basement includes transitional crust, oceanic crust, and volcanic rifted crust in the northern basin (volcanic seamounts, sills and volcaniclastics occur in parts of this latter basement domain).

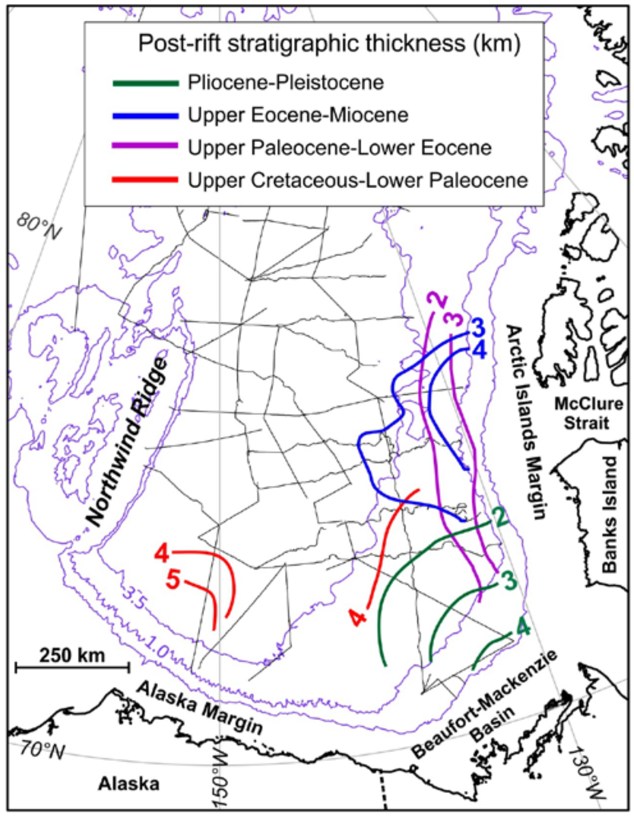



**Figure 7.** Select isopach contours outlining variations in post-rift sediment deposition in Canada Basin (modified from Mosher et al., 2012). The oldest basin strata (Upper Cretaceous to Lower Paleocene) were mainly derived from southern areas, including significant sediment input from the western Alaska margin. Middle Cenozoic strata (Upper Paleocene to Lower Eocene, and Upper Eocene to Miocene) have principal source areas east of the basin, along the Arctic Islands margin. The youngest basin strata (Plio-Pleistocene) were mainly derived from areas southeast of the Beaufort-Mackenzie Basin. Thin black lines indicate UNCLOS seismic lines.

## PETROLEUM SYSTEMS

### Reservoir rocks

Reservoirs in syn-rift grabens and half-grabens may include shallow marine Lower Cretaceous sandstones, similar to known oil and gas reservoirs in the Mackenzie Delta region (Figure 5; Dixon, 1996). Early Jurassic or older reservoirs may also occur in deeper parts of rift sub-basins. Syn-rift sandstones in Canada Basin likely have poor reservoir quality due to deep burial depths.

Reservoirs in post-rift Cenozoic strata may include turbidite sandstones in slope, submarine fan, and basin plain settings. Depositional environments including channels, fan lobes, and basin plain sheets (Figure 8). The variable Cenozoic sediment source areas and multiple periods of basin margin lowstands (Figures 5, 7) appear to have resulted in widespread turbidite deposition across the basin. Seismic reflection data indicate fan lobe and sheet deposits extend laterally for distances of tens to hundreds of kilometres (Figures 6, 8). Channel sandstone reservoirs are likely more limited in distribution, with deposition in paleo-slope or inner fan settings in southern and eastern parts of the basin.

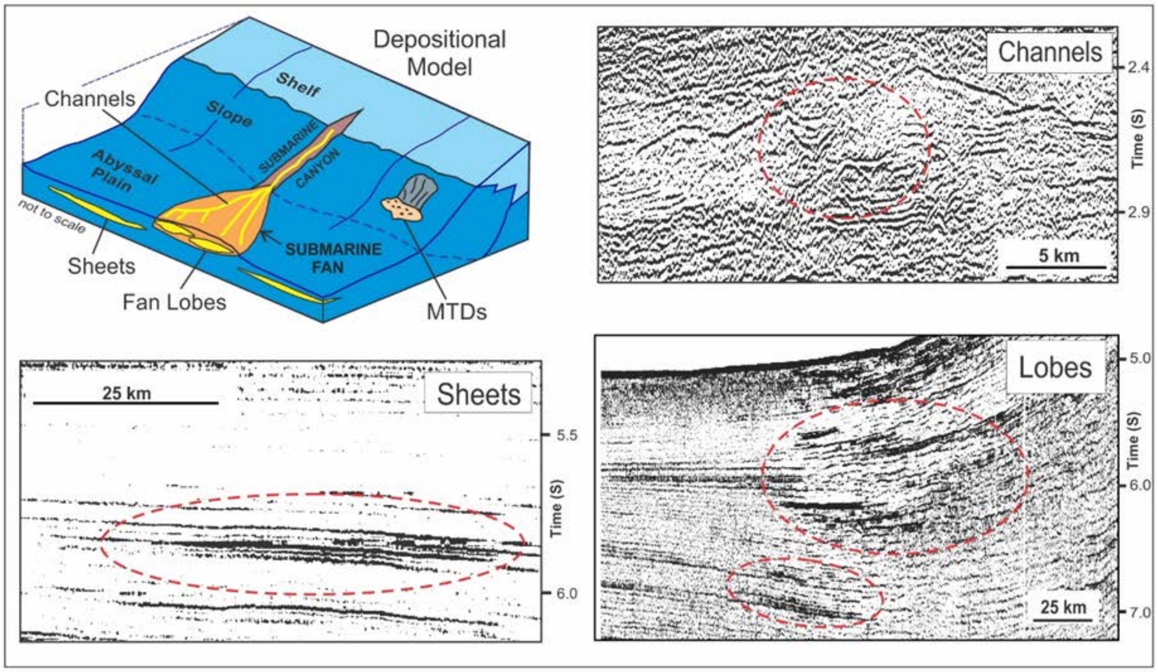



**Figure 8.** Schematic depositional model and seismic examples of interpreted deep-marine sandstones in Canada Basin, including submarine channels, fan lobes, and basin-plain sheets. Sandstone intervals, characterised by high amplitude reflections, are widespread in base-of-slope to basin-plain fan lobe and sheet deposits. Enhanced submarine fan deposition likely occur during periods of relative sea-level lowstands, including the latest Cretaceous, middle Eocene, early Oligocene, and late Miocene (Figure 5). Mass transport deposits (MTDs) are common in Plio-Pleistocene sections in southern and eastern slope areas (seismic example in Figure 6).

Global depositional analogs for Canada Basin include the deep-water Amazon, Niger and Mississippi submarine fans. These large river-fed fan complexes contain turbidite sandstones deposited in channels, lobes and sheets, in water depths up to 3000 to 4000 m, several hundred kilometers basinward from paleo-shelf edges (Stelting et al., 1986: Lopez, 2001).

Oil and gas reservoirs have been discovered in Cenozoic deep-marine sandstones in several wells in the northern Beaufort-Mackenzie Basin, adjacent to Canada Basin (Figure 3). The reservoirs occur in submarine fan channel and basin plain sandstones, characterised by good reservoir quality (porosity and permeability up to 25% and 200 millidarcies; Figure 9). Hydrocarbon flow rates up to 6045 barrels oil/day and 10 million cubic feet gas/day were tested from turbidite sandstone reservoirs in the Kopanoar M-13 and Kenalooak J-94 wells, respectively. Porosity-depth trends in deep-marine Cenozoic sandstones in Beaufort-Mackenzie wells indicate good to excellent reservoir quality to subsurface depths of 5000 m, and by projection fair to good quality to depths of 7000 m (Figure 9). These reservoir trends may be applicable to strata in Canada Basin.

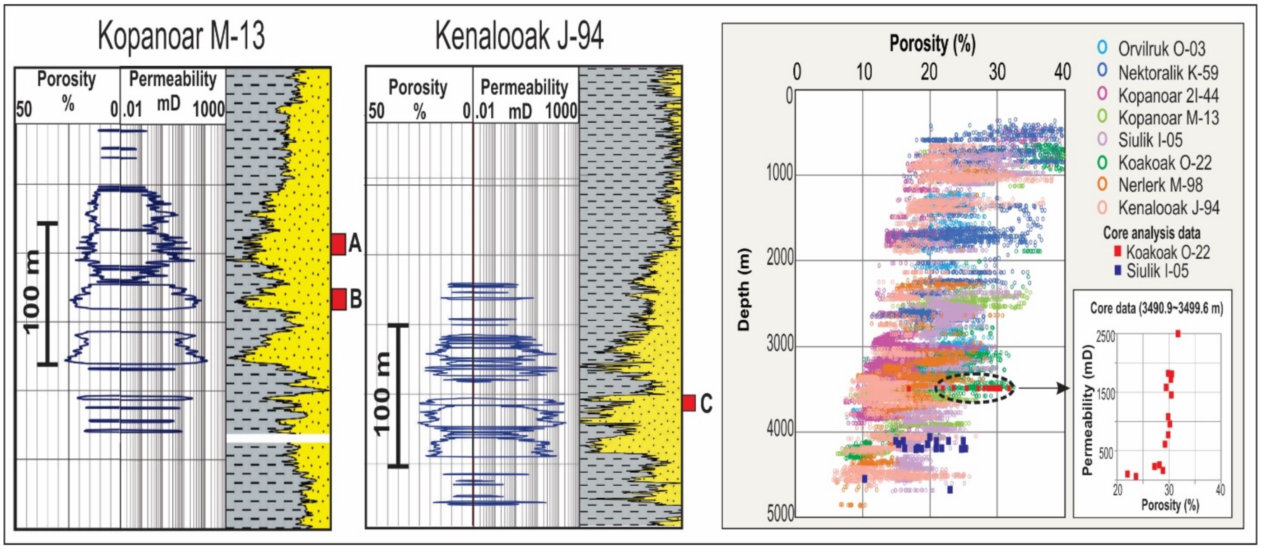



**Figure 9.** Petrophysical measurements of reservoir characteristics of Cenozoic deep-marine sandstones in wells in the northern Beaufort-Mackenzie Basin (locations in Figure 3). Left panels illustrate hydrocarbon reservoirs in Oligocene channel and sheet sandstones in the Kopanoar M-13 well (3500-3600 m depth) and Kenalooak J-94 well (4450-4550 m depth). Porosity and permeability of the oil and gas reservoirs vary from 15-25% and 10-150 millidarcies (mD). Drill-stem flow tests in the M-13 well recovered oil at 961 $m^3$/day and gas at 128,000 $m^3$/day (interval A), and oil at 66 $m^3$/day oil (interval B). A test in the J-94 well (interval C) recovered gas at 110,435 $m^3$/day. Right panel illustrates depth-porosity trends in deep-marine sandstones in eight wells. Median and maximum porosity are 23% and 35% at 2000m, and 15% and 27% at 4000m. Core data from the Koakoak O-22 well indicate Oligocene sandstones at 3490.9-3499.6 m depth have excellent reservoir quality, with average porosity and permeability of 28% and 1067 mD, respectively. Projected trends indicate median and maximum porosity may be 10% and 20% at 6000m, and 7% and 16% at 7000m. A porosity cutoff of 10% was used for the resource calculations.

## Source rocks

Numerous wells and conventional oil and gas fields in the Beaufort-Mackenzie Basin and northern Alaska provide information on a variety of source rocks, many of which may be present in Canada Basin (Figure 5; Dixon et al., 1996; Peters et al., 2006; Chen et al., 2007; Bird and Houseknecht, 2011).

In the Beaufort-Mackenzie Basin, Jurassic-Lower Cretaceous source rocks include marine shales within the Husky, McGuire, and Mount Goodenough formations. These source rocks typically vary in TOC from 2 to 4% and contain Type II and III kerogens. These source units may be present in synrift grabens in parts of Canada Basin. Depending on the age of rift onset, older syn-rift source rocks may include Late Triassic marine shales (Shublik Formation). Upper Cretaceous strata probably contain the most widespread and significant source rocks in Canada Basin. These oil-prone source rocks include marine shales within the Boundary Creek and Smoking Hills sequences. The source units vary in TOC from 2 to 10% and predominantly contain Type II and III kerogens. Most of the discovered oil accumulations in Cenozoic reservoirs in the offshore Beaufort-Mackenzie Basin were derived from Upper Cretaceous source rocks. Potential Cenozoic source rocks in Canada Basin include shales in Eocene-Paleocene strata, equivalent to the

Richards, Aklak and Taglu sequences. In the Beaufort-Mackenzie Basin, Cenozoic shale source rocks vary in TOC from 1.0 to 4.0% and predominantly contain Type III kerogens.

**Hydrocarbon Generation Models**

Basin subsidence - thermal modeling was undertaken to evaluate hydrocarbon generation potential for source rocks in the Canada Basin. One-dimensional models were derived for different locations in the basin, representing a range of basement depths, stratigraphy and crustal domains (Figs. 3, 10). The model locations include; 1- southeastern basin in an area of transitional crust and 12.4 km thick sedimentary section; 2 – southwestern basin in an area of transitional crust and 8 km sedimentary section; 3 - central Canada Basin in an area of oceanic crust and 4.8 km sedimentary section; and, 4 - northern Canada Basin in an area of extended volcanic crust (AM-LIP domain) and 4.4 km sedimentary section. A fifth hydrocarbon generation model (not shown in this report) indicated that the sedimentary section in Nautilus Subbasin is too thin for oil or gas generation. Lithostratigraphic sections and known source rock characteristics (from the adjacent Beaufort-Mackenzie Basin) were defined for Jurassic, Upper Cretaceous and Cenozoic (Eocene) source intervals for each model location (Figure 10). Interpreted geothermal gradients were derived from sparse basin heat flow measurements (Louden et al., 1990), seismic velocity analyses (Shimeld et al., 2015), and measured values from wells in the northern Beaufort-Mackenzie Basin (Hu et al. 2014). Low geothermal gradients (26-36 $^{O}$C/km) were used for southern basin models (1 and 2) where sedimentation rates were high, and moderate geothermal gradients (42-43 $^{O}$C/km) were used for central and northern basin models (3 and 4) in areas of oceanic/volcanic crust.

The basin models indicate significant oil generation potential for Upper Cretaceous source rocks in all basin areas (Figure 10). Jurassic syn-rift source rocks have gas generation potential in areas outside of the oceanic crustal domain (models 1, 2, 4). Cenozoic (Eocene) source rocks have gas generation potential in the deeply buried southern and eastern part of the basin (model 1). Models indicate Jurassic and Cenozoic source rocks do not have significant oil generation potential.

The models also indicate variability in the timing of oil or gas generation, with peak generation varying from Late Cretaceous to Pliocene, depending on basin depths and source rock age. Oil generation from the presumably widespread Upper Cretaceous source rocks occurred in the Late Eocene to Early Miocene, with the exception of the southwest basin area (model 2) where generation may have started in the Paleocene. Most of the gas generation from Jurassic source rocks occurred in the Late Cretaceous, in southern basin areas. Gas generation from Eocene source rocks (in the southeastern basin area) occurred in the Plio-Pleistocene, during periods of rapid Neogene sedimentation. The timing of oil or gas generation relative to trap formation is an important consideration in evaluating petroleum potential.

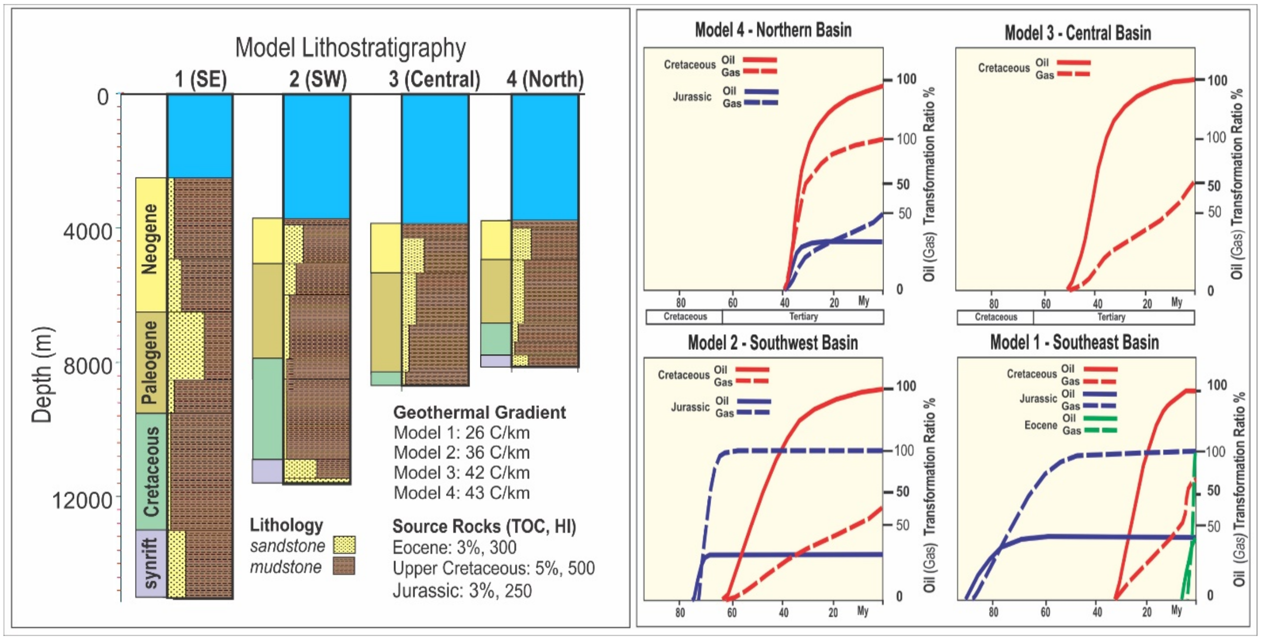



**Figure 10.** Canada Basin hydrocarbon generation models 1 to 4 (locations in Figure 3). Models 1 and 2 are representative of the Southern and Eastern assessment area (transitional crust); Models 3 and 4 are representative of the Central and Northern assessment area (oceanic or transitional/volcanic crust). Left panel indicates model lithostratigraphy and selected thermal and source rock parameters. Right panels indicate the magnitude and timing of oil or gas transformation for Jurassic, Upper Cretaceous, and Eocene source rock units. Hydrocarbon transformation models indicate Upper Cretaceous source rocks may have generated significant volumes of oil, in all basin areas.

## Traps

A variety of potential structural, stratigraphic and combined structural- stratigraphic hydrocarbon traps are present in the Canada Basin. Trap types in Mesozoic syn-rift grabens or half grabens include fault blocks with tilted or rotated strata (Figure 6). Cenozoic post-rift structural traps include tectonic and gravity detachment folds, drape folds, and fault blocks (Figure 11). Tectonic folds occur in the Beaufort foldbelt, encompassing the southeastern Canada Basin (Figure 3). Gravity folds are common in continental slope areas west of Banks Island and north of the Alaska. Drape folds, common throughout the abyssal plain region, are associated with basement uplifts or high-standing blocks. Combination structural and stratigraphic traps include onlap pinchouts, some with local fault components. Stacked onlap patterns are associated with margins of the Northwind and Alpha ridges and other high-standing basement features (Figure 6). Potential stratigraphic traps in post-rift sections may be associated with lithofacies variations (sandstone to shale) in submarine fan lobes, channels or basin plain sheets (Figure 8).

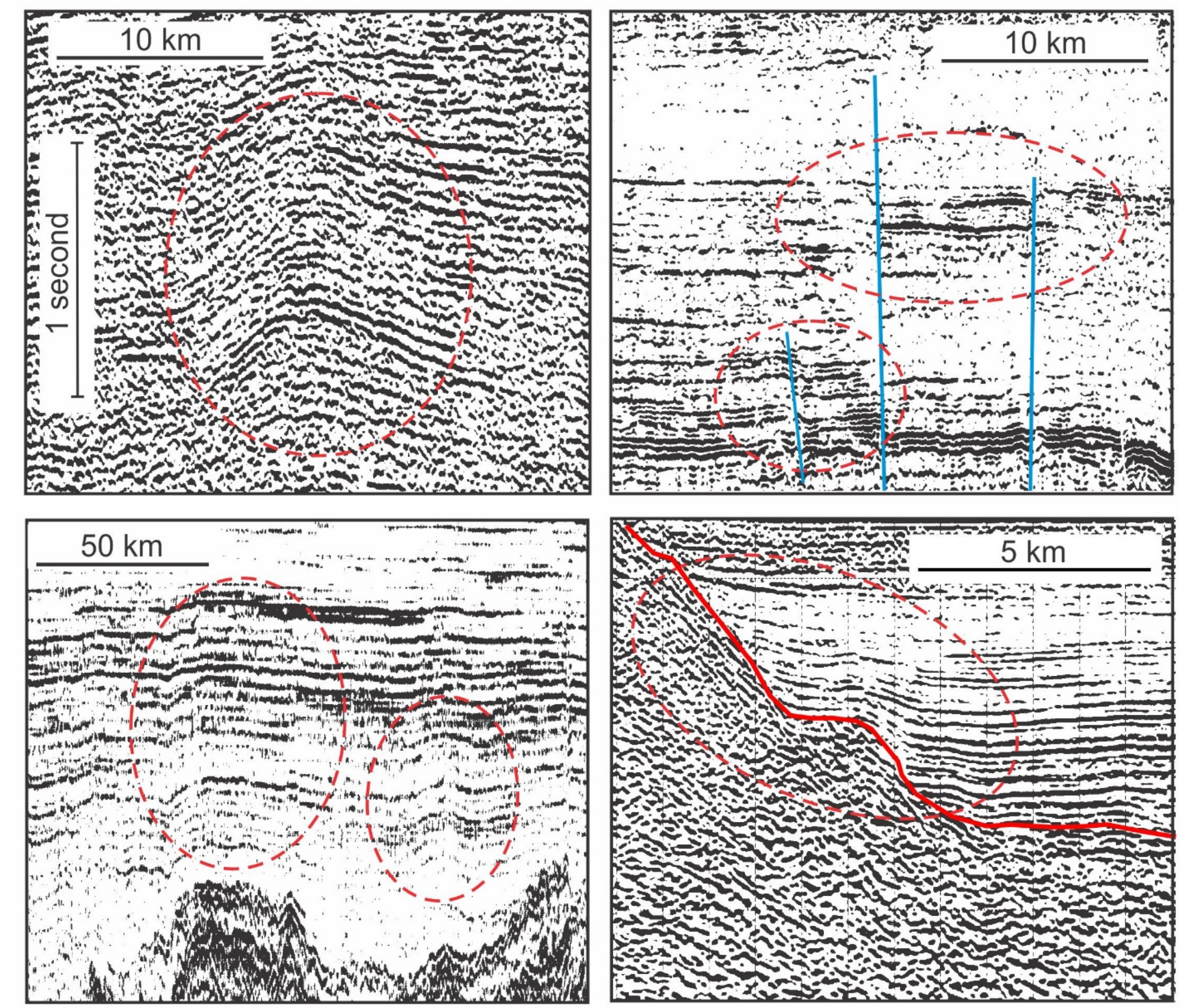



**Figure 11.** Seismic examples of possible structural or stratigraphic hydrocarbon trap types in Cenozoic post-rift strata in Canada Basin: top left - tectonic/gravity folds; top right - fault blocks; bottom left – basement drape folds; bottom right - stratigraphic traps associated with basement onlap. Seismic figures displayed at similar (vertical) time scales.

## Seals

Analyses of seismic velocities indicate the sedimentary succession in the Canada Basin consists of large volumes of fine-grained mudstones (Shimeld et al., 2015). These pelagic/hemipelagic deposits should provide adequate seals for many reservoirs. In general, sealing capacity increases with greater clay content (Weimer and Slatt, 2007). Reservoir seals may be adversely affected by leaky faults, late-stage faulting of early formed traps, updip leakage from channel-fill reservoirs in slope settings, and overpressure (Weimer and Slatt, 2007). Overpressure may occur in southern and eastern parts of Canada Basin, in areas with high Cenozoic sedimentation rates.

## Hydrocarbon Indicators

Geophysical indications of oil or gas accumulations are present in many seismic reflection profiles in Canada Basin. Direct hydrocarbon indicators (DHIs) include reflection amplitude anomalies, frequency anomalies, and flat spots (Figure 12). The DHIs are associated with Cenozoic strata in structural highs and faulted anticlines. Preliminary interpretations indicate there are at least 100 prospects in Canada Basin with direct seismic hydrocarbon indicator anomalies. The abundance and widespread distribution of DHIs provides compelling evidence of effective petroleum systems in the basin.

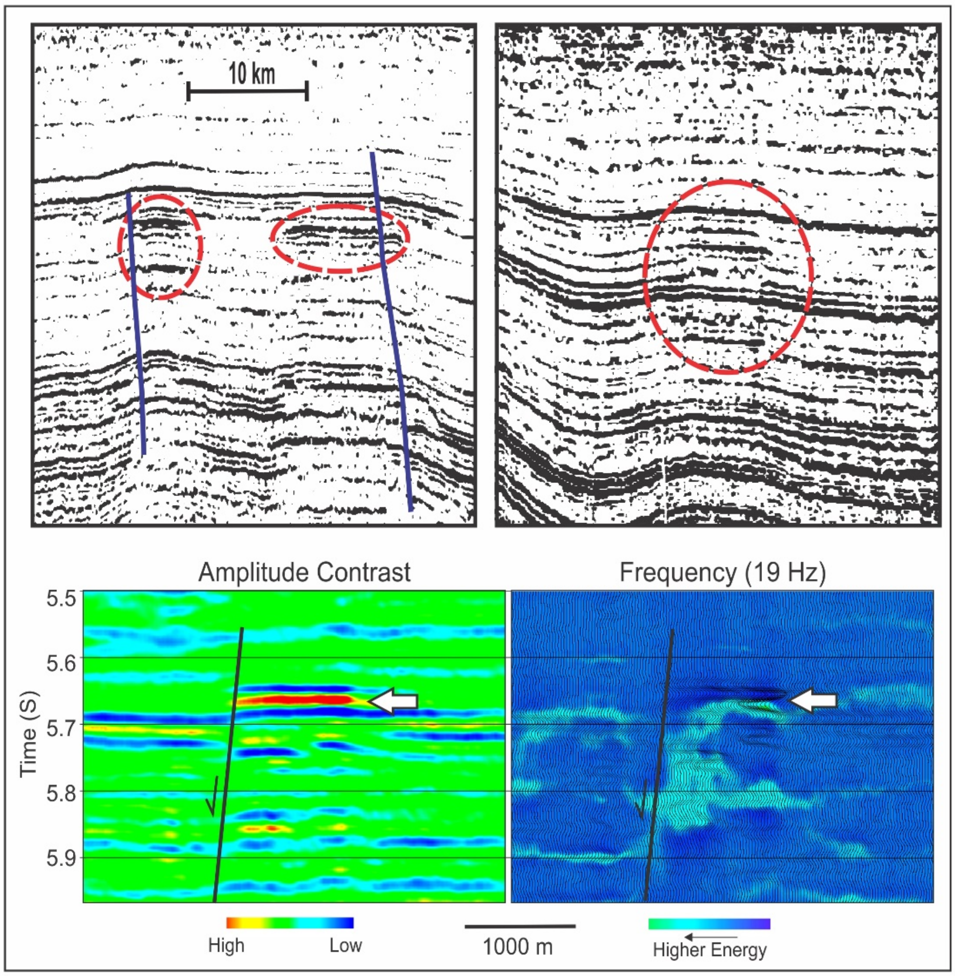



**Figure 12.** Canada Basin UNCLOS seismic profile segments with interpreted direct hydrocarbon indicators (DHIs). Top panels - reflection bright spots (dashed red ovals) in low relief drape anticlines, with anomalies in top left example linked to steep dipping faults. The conformance of the seismic anomalies to structurally high areas provides increased confidence in the interpretation of hydrocarbon indicators. Bottom panel - seismic amplitude and frequency displays of a Cenozoic fault block structure. Fault-bounded amplitude anomaly (arrow) is an interpreted DHI. Low frequency anomalies (bottom right panel) occur in parts of the section below the amplitude anomaly. The combination of amplitude bright spots and low frequency shadow zones is often diagnostic of gas-charged reservoirs (Castagona et al., 2003).

## CONVENTIONAL PETROLEUM RESOURCES

Estimates of conventional oil and natural gas potential for Canada Basin were derived using both a play-based volumetric probability method and a basin-scale global analogue method.

The volumetric probability assessment method developed by the Geological Survey of Canada (Lee, 1993) is appropriate for the evaluation of conceptual petroleum plays, such as those in the frontier Canada Basin. The volumetric method used in this study is a revised version of the original GSC methodology, with lognormal distributions of volumetric parameters replaced with beta distributions. Beta distributions, widely used in resource assessments, can approximate lognormal distributions in shape and offer wider flexibility in the variation of volumetric reservoir parameters (Olea, 2011; Attanasi and Freeman, 2015). Beta distributions of reservoir parameters were statistically combined (by Monte Carlo simulations) to obtain field size distributions. The method also incorporated the evaluation of the exploration chance of success (COS) of prospects within a play. The COS is the predicted presence or adequacy of necessary geological factors for the formation of oil or gas accumulations, including reservoir, trap, source, and timing of hydrocarbon generation. COS factors were combined with estimates of numbers prospects and field size distributions to derive play and basin resource potential.

The global analogue method provides estimates of basin-scale oil/gas yields from producing analogue basins. Studies have demonstrated that resource richness (yield as a function of sediment volume) and field-size distributions are functions of the geological characteristics and classification of sedimentary basins (Klemme,1980, 1986). Areal yields from analogous producing basins can be used to estimate resource potential in a frontier basin. Details of the GSC application of a global analogue assessment were presented by Brent and others (2013). Global analogue assessment results provide a useful comparison to the more detailed volumetric probability methodology.

### Volumetric Probability Assessment

Five conceptual petroleum plays were defined for the Canada Basin, four of which had sufficient data for a volumetric probability assessment. The plays were defined based on the age of reservoir strata in which oil and/or gas accumulations may occur, and basin setting, including sedimentary thickness and heat flow. The plays include a Mesozoic syn-rift play and four Cenozoic post-rift plays. The four Cenozoic plays were assessed for oil and gas resources, with separate calculations for each hydrocarbon type. Probability distributions of interpreted reservoir parameters (net pay, porosity, hydrocarbon saturation, formation volume factor, recovery factor), numbers and sizes of prospects, and geologic COS values for the four Cenozoic plays are outlined in Appendix 1. Reservoir parameters were partly constrained by data from wells in the Beaufort-Mackenzie Basin and analogous petroleum-bearing basins. A key analog dataset for the reservoir parameters was derived from the deep-water Gulf of Mexico Basin, where many oil and gas fields have been discovered in Cenozoic submarine-fan reservoirs (BOEM, 2013). The numbers and sizes of prospects were estimated from UNCLOS and other seismic data, with extrapolation of prospect parameters into basin areas with little or no data. COS factors were based on opinions of the assessment team, partly constrained by seismic and geological data.

***Mesozoic Syn-rift Play***

The Mesozoic syn-rift play includes all prospects within shallow marine siliciclastic reservoirs within synrift grabens or half grabens. The play extends over most of Canada Basin, except the central oceanic crust portion (Figure 3). Hydrocarbon generation models (Figure 10) indicate the syn-rift play may have some gas potential. In most parts of the basin, syn-rift structures are not well resolved due to limitations in imaging depths and quality of available seismic data. Due to insufficient information on numbers and sizes of prospects, the syn-rift play was not assessed quantitatively.

***Cenozoic Post-rift Plays***

The post-rift succession covers almost the entire Canada Basin. Based on differences in sediment thickness, proximity to sediment source areas and assumed geothermal gradients, two assessment areas were defined for the post-rift basin; a Southern and Eastern (S-E) area, and a Northern and Central (N-C) area (Figure 3). The S-E area has thick post-rift sedimentary successions (8 to 13 km) located close to main sediment source areas along the northwest Canada and northern Alaska continental margins. Hydrocarbon generation models 1 and 2 (Figure 10) illustrate the source rock potential for the S-E area. The N-C area has thinner post-rift sediments (1 to 8 km) that are more distal to the main sediment source areas. Parts of this assessment area were affected by magmatism related to the AM-LIP (Figure 3), which may have led to increased heat flow and accelerated sediment porosity reduction with depth (Shimeld et al., 2015). Hydrocarbon generation models 3 and 4 demonstrate the source rock potential for the N-C area.

Lower and Upper Cenozoic plays were defined for each of the post-rift assessment areas. The Lower Cenozoic plays include all deep structural and stratigraphic prospects in Paleocene to Middle Eocene turbidite sandstone reservoirs (Figure 5). The Upper Cenozoic plays include all shallow to intermediate depth prospects in Upper Eocene to Pleistocene sandstones.

***COS Factors***

The main factors believed to affect the chance of success (COS) for prospects in the Cenozoic plays include the presence of reservoir facies, trap closure, and timing of hydrocarbon generation. The reservoir factor reflects the possible sporadic or discontinuous distribution of deep marine sandstones, particularly in paleo-slope and inner fan settings where channel-levee and inter-channel deposits may be common. The closure/seal factor reflects the limited seismic control and lack of three-dimensional information, with most prospects identified in only a single seismic line. The timing factor, of particular relevance to the Upper Cenozoic plays, reflects the model observations that some oil and gas generation may have preceded trap development. There is insufficient information to differentiate COS levels for specific trap types (stratigraphic, structural, combined stratigraphic-structural). The COS for prospects in the Canada Basin oil plays are estimated to be lower than in the gas plays. The reduced probability of occurrence for oil accumulations reflects the enhanced risk associated with timing of oil generation relative to trap formation.

***Assessment Results***

Probability distribution plots of recoverable oil, solution gas and fee gas for the four Cenozoic plays are illustrated in Figure 13. Mean estimates of recoverable petroleum resources for the Upper Cenozoic play in the Southern and Eastern assessment area are 225.7 million m$^3$ (1.4 billion barrels) oil, 83.5 billion m$^3$ (2.9 Tcf) solution gas (from produced oil reservoirs), and 115 billion m$^3$ (4 Tcf) free gas. Mean recoverable estimates for the Lower Cenozoic play in the S-E assessment area are 249.6 million m$^3$ (1.5 billion barrels) oil, 117.5 billion m$^3$ (4.1 Tcf) solution gas, and 199.9 billion m$^3$ (7 Tcf) free gas.

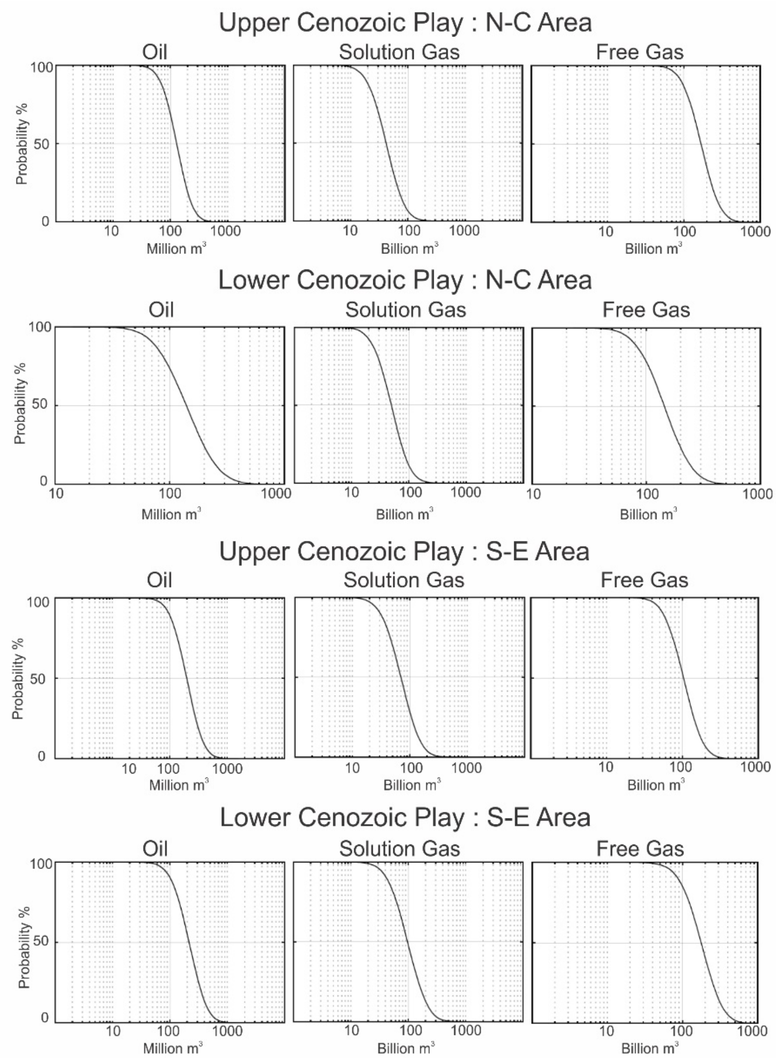



**Figure 13.** Probability distribution plots of recoverable oil, solution gas, and free gas in Upper Cenozoic and Lower Cenozoic plays in Northern-Central (N-C) and Southern-Eastern (S-E) assessment areas. Mean values of resource distributions noted in text.

Mean estimates of recoverable petroleum resources for the Upper Cenozoic play in the Northern and Central assessment area are 146.2 million $m^3$ (0.92 billion barrels) oil, 48.9 billion $m^3$ (1.7 Tcf) solution gas, and 185.7 billion $m^3$ (6.5 Tcf) free gas. Mean estimates of recoverable resources for the Lower Cenozoic play in the N-C assessment area are 157.3 million $m^3$ (0.99 billion barrels) oil, 58.3 billion $m^3$ (2 Tcf) solution gas, and 158.5 billion $m^3$ (5.6 Tcf) free gas.

The mean estimates of total recoverable resource potential in Canada Basin (from the four plays combined) are 779 million $m^3$ (4.9 billion barrels) oil, 659 billion $m^3$ (23 Tcf) free gas, and 308 billion $m^3$ (10.8 Tcf) solution gas (Figure 14). The range of total resource estimates from high to low probability (P90 to P10) are 518 to 1077 million $m^3$ (3.2 to 6.7 billion barrels) oil, 462 to 882 billion $m^3$ (16 to 26 Tcf) free gas, and 189 to 450 billion $m^3$ (6.6 to 15.9 Tcf) solution gas. Using an approximate energy equivalent factor of 6000 cubic feet of gas to 1 barrel of oil, the total recoverable energy resource potential (oil and gas combined) in Canada Basin is estimated at 1683 million $m^3$ (10.5 billion barrels) oil equivalent (mean value). High to low probability estimates for total energy resource potential are 1263 to 2154 million $m^3$ (7.9 to 13.5 billion barrels) oil equivalent.

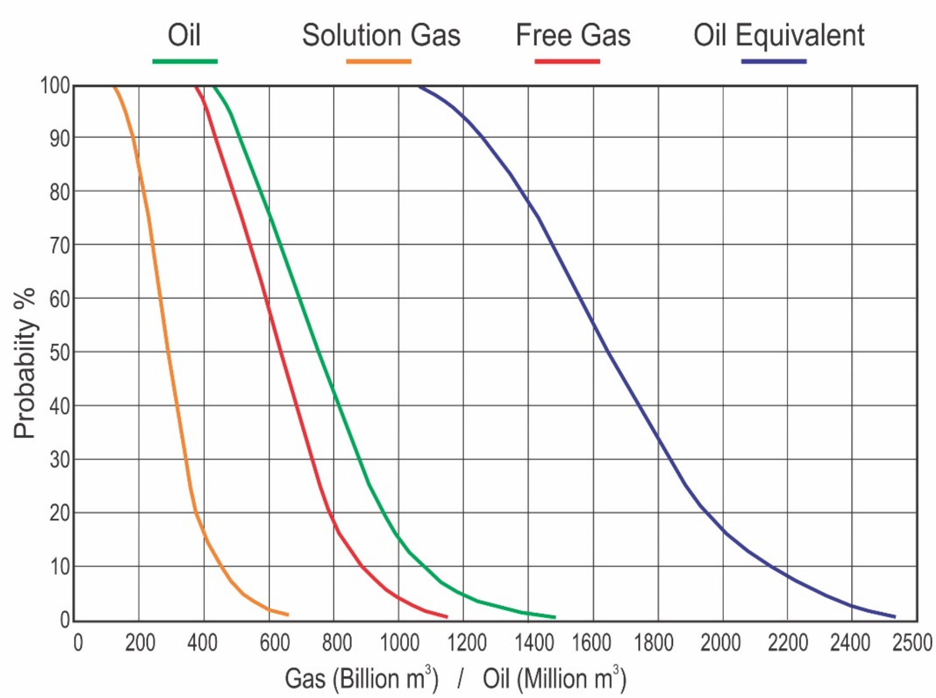



**Figure 14.** Probability distribution plots of total recoverable oil, solution gas, free gas, and combined oil equivalent in Canada Basin. Mean, high probability (P90) and low probability (P10) values of resource distributions noted in text.

## Global Analogue Assessment

Global basin analogues for Canada Basin were selected from the USGS World Analog Database (Charpentier et al., 2008). Criteria used to select analogue basins included crustal setting (transitional or oceanic basement) and depositional environment (deep-water slope and turbidite systems). Basins with salt structures or carbonate reservoirs were not included. Key analogue basins/areas include the Brunei-Sabah, Kutei, Guyana-Suriname, Sergipe-Alagoas, Pelotas, Niger Delta, Southwest Africa Offshore, Amazon Fan, Mississippi Fan, and Indus Fan basins. A good example of a global analogue to Canada Basin is the offshore Niger Delta Basin that contains Cenozoic coarse-grained turbidite reservoirs (Akata Formation) deposited in deep-marine settings basinward of shallow marine delta systems. Numerous oil and gas fields have been discovered in Akata Formation reservoirs in the deep-water Niger Basin. The USGS estimated a petroleum resource potential of 18.6 billion barrels of oil and 47.5 Tcf of gas in the 300,000 $km^2$ Akata play area (Charpentier et al., 2008).

Triangle distributions of areal yields for oil and natural gas (recoverable volumes/$km^2$) for the analogue basins were derived and statistically combined with the prospective area for Canada Basin to generate the estimated resource potential. A simple Pareto field size distribution was assumed for the analogue assessment (Chen and Sinding-Larsen, 1994).

The global analogue method predicts mean recoverable resource volumes for Canada Basin are 6.4 billion barrels oil and 27.5 Tcf gas (total of 11 billion barrels oil equivalent). These recoverable volumes are similar to the basin resource potential derived from the volumetric probability method (10.5 billion barrels oil equivalent).

## UNCONVENTIONAL PETROLEUM RESOURCES

### Gas Hydrates

Gas hydrates, naturally occurring ice-like combinations of methane and water, are present in Canada Basin. Gas hydrates are commonly preserved in deep marine environments with temperatures and pressures suitable for hydrate stability (Figure 15). In Canada Basin, the gas hydrate stability zone may extend over the entire continental slope, rise and abyssal plain (Max and Lowrie, 1993). Seismic profiles across the continental slope of the Alaska and Canadian Beaufort Sea margin reveal bottom simulating reflections (BSRs) indicative of a gas hydrate layer (Figure 15). Gas hydrates were encountered in shallow piston cores in the continental slope north of Alaska, in an area with seismic BSR anomalies (Hart et al., 2011; location in Figure 15).

Stability zone models and seismic data observations indicate the sub-sea gas hydrate layer in Canada Basin may be 200 to 900 m thick. Although a potentially large unconventional gas resource, there is currently insufficient information to estimate recoverable hydrate-associated gas volumes.

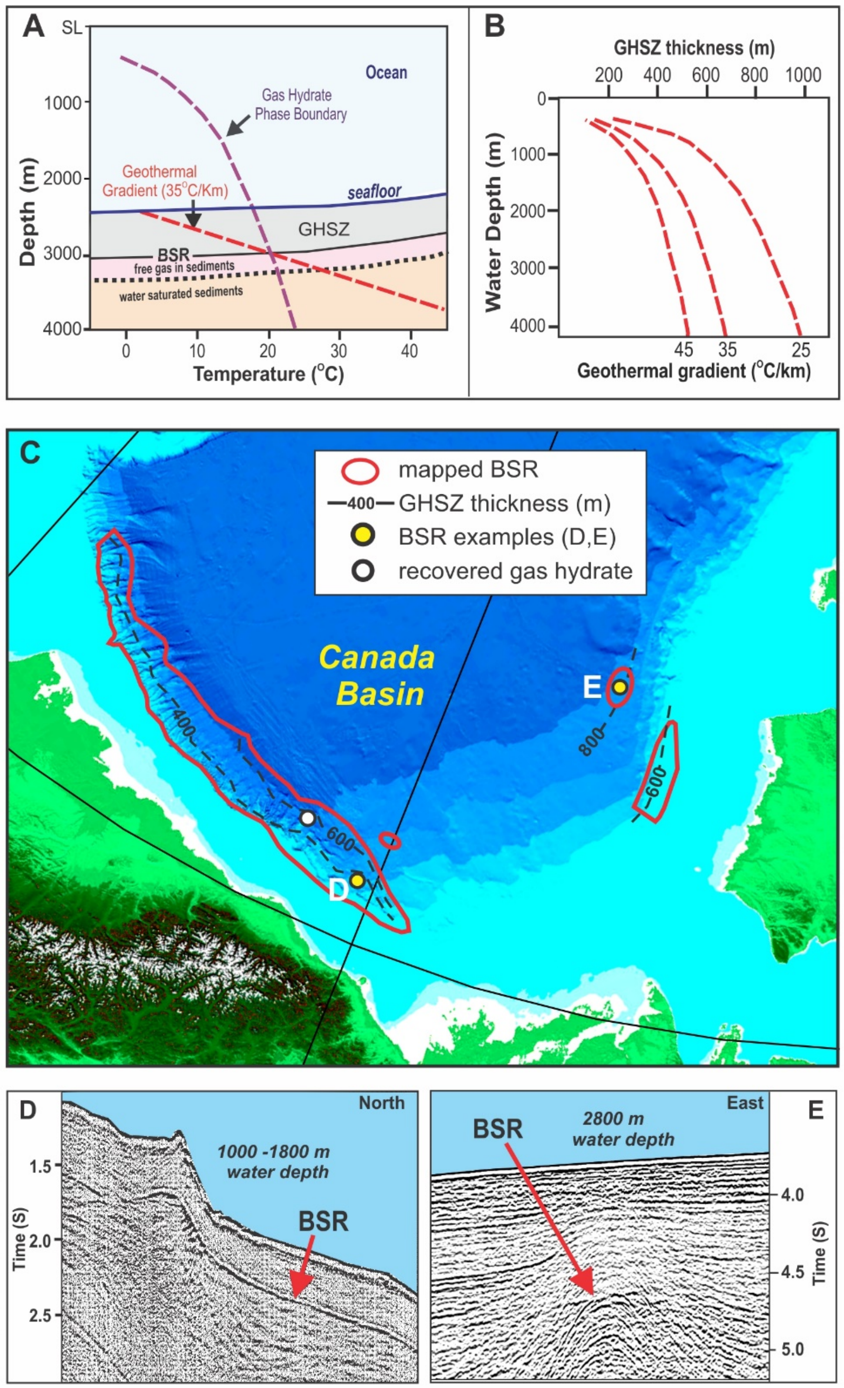



**Figure 15.** Geophysical models and seismic indicators of natural gas hydrates in the deep-water Canada Basin. A - model of the gas hydrate stability zone (GHSZ) in a deep-water setting (modified from Hyndman and Dallimore, 2011); B – model of GHSZ thickness relative to select geothermal gradients and Arctic ocean water depths (adapted from MacLeod, 1982); C – locations of seismically-mapped bottom simulating reflections (BSRs) and estimated thickness of the GHSZ around the southern margin of Canada Basin (Lorenson et al., 2011, Reidel et al., 2017, and this study); D and E - seismic data examples of BSRs beneath the continental slope north of Alaska and west of Banks Island.

## CONCLUSIONS

The conventional oil and gas potential in the deep-water Canada Basin was evaluated with two assessment methods, a play-based volumetric probability method and a basin-scale global analogue method. Five conceptual oil and gas plays were defined in the play-based study. Quantitative oil and gas assessments were derived for four Cenozoic plays in post-rift strata.

The assessment results indicate the Canada Basin has significant conventional petroleum resource potential. Mean estimates of total recoverable resources are 779 million $m^3$ (4.9 billion barrels) oil, 659 billion $m^3$ (23 Tcf) free gas, and 308 billion $m^3$ (10.8 Tcf) solution gas. The global analogue based assessment produced recoverable resource estimates of 6.4 billion barrels oil and 27.5 Tcf free gas (mean values). The similar magnitude of resource estimates from independent methods increases the level of confidence in the assessment of this region.

Gas hydrates may represent a significant unconventional petroleum resource in Canada Basin, but potential recoverable gas volumes are currently difficult to estimate.


## ACKNOWLEDGMENTS

The authors thank J. Shimeld for providing Unclos seismic data and maps, D. Mosher, D. Chian, R. Jackson and G. Oakey for information on geophysical studies in the region, M. Duchesne for seismic attribute processing, H. King for reviewing seismic correlations, G. Sonnichsen for program management, and E. Atkinson for a review of an early version of the report.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## APPENDIX – ASSESSMENT PLAY DATA

### Southern and Eastern Assessment Area

**Upper Cenozoic Oil Play** I **Upper Cenozoic Gas Play**

| Parameter | Minimum | Median | Maximum | Minimum | Median | Maximum |
|---|---|---|---|---|---|---|
| **Area (km²)** | 5 | 20 | 450 | 5 | 20 | 450 |
| **Net pay (m)** | 2 | 10 | 85 | 2 | 7 | 62 |
| **Porosity (%)** | 10 | 21 | 40 | 10 | 21 | 40 |
| **Oil/Gas Saturation (%)** | 45 | 77 | 90 | 40 | 76 | 90 |
| **Formation Volume Factor** | 1.005 | 1.4 | 3.0 | .003 | .0034 | .0041 |
| **Gas/Oil ratio (m³/m³)** | 20 | 350 | 1000 | | | |
| **Number of Prospects *** | 121 | 255 | 300 | 121 | 255 | 300 |
| **Recovery Factor** | 15 | 25 | 45 | 50 | 65 | 80 |
| **Closure COS (%)** | | **70** | | | **70** | |
| **Reservoir COS (%)** | | **80** | | | **80** | |
| **Source COS (%)** | | **80** | | | **60** | |
| **Timing COS (%)** | | **30** | | | **40** | |
| **Total COS (%)** | | **13** | | | **13** | |

***** Individual prospects have potential to contain oil or free gas accumulations, or both hydrocarbon types

**Lower Cenozoic Oil Play** I **Lower Cenozoic Gas Play**

| Parameter | Minimum | Median | Maximum | Minimum | Median | Maximum |
|---|---|---|---|---|---|---|
| **Area (km²)** | 5 | 50 | 312 | 5 | 50 | 312 |
| **Net pay (m)** | 2 | 10 | 85 | 2 | 7 | 62 |
| **Porosity (%)** | 10 | 15 | 36 | 10 | 15 | 36 |
| **Oil/Gas Saturation (%)** | 45 | 77 | 90 | 40 | 76 | 90 |
| **Formation Volume Factor** | 1.005 | 1.45 | 3.0 | .003 | .0034 | .0045 |
| **Gas/Oil ratio (m³/m³)** | 50 | 450 | 1200 | | | |
| **Number of Prospects** | 48 | 108 | 150 | 48 | 108 | 150 |
| **Recovery Factor** | 15 | 25 | 45 | 55 | 70 | 85 |
| **Closure COS (%)** | | 60 | | | 60 | |
| **Reservoir COS (%)** | | 60 | | | 60 | |
| **Source COS (%)** | | 80 | | | 80 | |
| **Timing COS (%)** | | 70 | | | 80 | |
| **Total COS (%)** | | 20 | | | 23 | |

**Northern and Central Assessment Area**

| Parameter | Upper Cenozoic Oil Play | | | Upper Cenozoic Gas Play | | |
|---|---|---|---|---|---|---|
| | Minimum | Median | Maximum | Minimum | Median | Maximum |
| Area (km²) | 5 | 12 | 450 | 5 | 12 | 450 |
| Net pay (m) | 2 | 10 | 85 | 2 | 7 | 62 |
| Porosity (%) | 10 | 24 | 40 | 10 | 24 | 40 |
| Oil/Gas Saturation (%) | 45 | 77 | 90 | 40 | 76 | 90 |
| Formation Volume Factor | 1.005 | 1.41 | 2.47 | .0029 | .0032 | .0039 |
| Gas/Oil ratio ($m^3/m^3$) | 20 | 320 | 900 | | | |
| Number of Prospects | 99 | 266 | 300 | 99 | 266 | 300 |
| Recovery Factor | 20 | 35 | 50 | 50 | 65 | 80 |
| Closure COS (%) | | 80 | | | 80 | |
| Reservoir COS (%) | | 80 | | | 80 | |
| Source COS (%) | | 90 | | | 90 | |
| Timing COS (%) | | 20 | | | 40 | |
| Total COS (%) | | 11 | | | 22 | |

| Parameter | Lower Cenozoic Oil Play | | | Lower Cenozoic Gas Play | | |
|---|---|---|---|---|---|---|
| | Minimum | Median | Maximum | Minimum | Median | Maximum |
| Area (km²) | 5 | 12 | 312 | 5 | 12 | 312 |
| Net pay (m) | 2 | 10 | 85 | 2 | 7 | 62 |
| Porosity (%) | 10 | 20 | 38 | 10 | 20 | 38 |
| Oil/Gas Saturation (%) | 40 | 77 | 90 | 36 | 76 | 90 |
| Gas/Oil ratio ($m^3/m^3$) | 20 | 350 | 1000 | | | |
| Formation Volume Factor | 1.005 | 1.45 | 3.065 | .002 | .0028 | .0038 |
| Number of Prospects | 85 | 246 | 300 | 85 | 246 | 300 |
| Recovery Factor | 20 | 35 | 50 | 50 | 65 | 80 |
| Closure COS (%) | | 70 | | | 70 | |
| Reservoir COS (%) | | 50 | | | 50 | |
| Source COS (%) | | 90 | | | 80 | |
| Timing COS (%) | | 50 | | | 90 | |
| Total COS (%) | | 15 | | | 25 | |