Natural Resources Canada / Ressources naturelles Canada

GEOLOGICAL SURVEY OF CANADA
OPEN FILE 8900

Resource assessments of northern Canadian sedimentary basins, 1973-2022

K. Dewing, L.E. Kung, C.J. Lister, E.A. Atkinson, and H.M. King

2022

Canada

ISSN 2816-7155
ISBN 978-0-660-44275-4
Catalogue No. M183-2/8900E-PDF

GEOLOGICAL SURVEY OF CANADA
OPEN FILE 8900

Resource assessments of northern Canadian sedimentary basins, 1973-2022

K. Dewing, L.E. Kung, C.J. Lister, E.A. Atkinson, and H.M. King

2022

Permanent link: https://doi.org/10.4095/330301

This publication is available for free download through GEOSCAN (https://geoscan.nrcan.gc.ca/).

Recommended citation
Dewing, K.E., Kung, L.E., Lister, C.J., Atkinson, E.A., and King, H.M., 2022. Resource assessments of northern Canadian sedimentary basins, 1973-2022; Geological Survey of Canada, Open File 8900, 91 p. https://doi.org/10.4095/330301

Publications in this series have not been edited; they are released as submitted by the author.

Table of Contents

List of Figures and Tables

Summary

Fifty-one resource assessments for Arctic Canada, completed between 1973 and 2022, were identified and evaluated. Of these, 24 are considered to be relevant in that they contain quantitative resource assessments, and an additional eight are prospectivity maps.

The assessment areas considered in these reports are the Beaufort-Mackenzie Delta region, the deep water Canada Basin that occupies the floor of the Arctic Ocean; the Arctic Margin from Banks Island to northern Ellesmere Island; the Sverdrup sedimentary basin underlying the northern Canadian Arctic Islands, the Lincoln and Makarov basins that lie north of Ellesmere Island and Greenland; the Baffin Margin that lies between Baffin-Devon-Ellesmere islands and Greenland; the Franklinian Margin that underlies the southern Arctic Islands, and the Foxe Basin that lies southwest of Baffin Island.

The assessed values have been standardized to **recoverable barrels of oil equivalent (BOE)** for those assessments reporting both oil and gas. Gas is converted to oil equivalent using the industry standard ratio of 6000:1. The range of **mean estimates of recoverable BOE** for each assessment area is shown by green bars in Figure 1; the mean estimate of recoverable BOE for an individual assessment is represented by a black circle. The four Baffin Margin assessments split geological provinces differently and cover spatially distinct geographic areas making it difficult to directly compare results. Deep water assessment areas in Baffin Bay have been apportioned 50% to Canada for this summary. The assessed resource for Lincoln Sea by Sørensen et al. (2011) includes Canadian and Greenland waters.

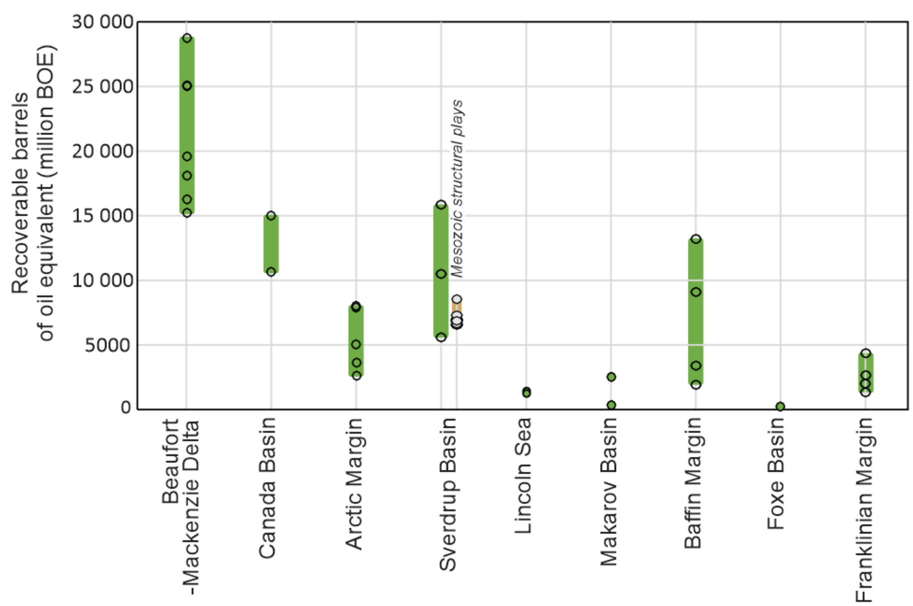


Figure 1. The range of **mean estimates of recoverable BOE** for each assessment area. See tables in the main text for references.

Evolving geological knowledge and improvements to methodology and computing power mean that the values reported for the same assessment area will change over time. All the historical assessments reviewed in this report have at least some limitations that affect their accuracy.

Introduction

Hydrocarbon resource assessments attempt to quantify energy resources in a region, and in some cases predict their most likely location. Resource assessments rely on two things: i) the conceptual understanding and density of information of a sedimentary basin and its petroleum systems at the time of assessment, and ii) the general state of knowledge about petroleum systems science and the statistical methodologies for resource assessments. Both these factors change over time, which means that the assessed hydrocarbon resource can change as more information becomes available (e.g. new drilling or seismic acquisition).

Resource assessments are performed on 'assessment areas'. These are geographic regions having distinct geological histories and petroleum potential. The resource potential of an assessment area is created by its tectonic history and the types and thickness of sediments and organic matter deposited over time. There are numerous methodologies for resource assessments. A brief summary of each method is provided in Appendix A, but this report is primarily focused on probabilistic assessment methods.

This document provides context and discusses relevance of historical northern Canada conventional hydrocarbon resource assessments, synthesizes the results, and converts previous assessed resources to a common set of units. This report is based on resource assessment documentation available in government publications, industry papers, and peer-reviewed journals, as well as files retained at the Geological Survey of Canada. For each report standard criteria have been applied with relevant data captured in consistent type and units. Extensive searches were conducted for supporting documents or data inputs to the published reports which has yielded varying results. Missing documentation are deemed as destroyed or misplaced.

Assessment Areas

This report captures information on previous resource assessments for nine assessment areas (see Figs. 2 and 6. A reading list is provided in Appendix A.1).

Beaufort-Mackenzie Delta. This assessment area includes onshore parts of the Mackenzie Delta and extends to the toe of the slope in the Beaufort Sea (Fig. 2). It is the second largest delta in North America and consists of thick accumulations of Cretaceous to Recent clastic strata. Deposition initiated as the Arctic Ocean formed in Jurassic to Early Cretaceous time due to the rotation between mainland Canada and the displaced Alaska-Chukotka block. The downward creep of the huge thickness of sediment created large-scale normal faulting in shallow areas and compressional folding in deep water areas. Ongoing tectonic compression in the western part of the area (Yukon-Alaska) created a complex fold belt. There are 263 exploration drill holes and 53 hydrocarbon discoveries in this assessment area (Fig. 4). There is a dense seismic grid over much of the area (Fig. 3).

Petroleum systems elements (Appendix A1) that result in hydrocarbon accumulations are: source rocks of Jurassic to Paleocene age, with the older marine source rocks more likely to be oil prone and the younger terrestrial source rocks gas prone; reservoir in Cretaceous to Cenozoic fluvial to shelf sandstone, and Cenozoic slope and fan sandstones; and hydrocarbon generation in the Cenozoic, synchronous with or post-dating, trap formation.

Canada Basin. The Canada Basin extends oceanward from the toe of the continental slope across the deep water parts of the Amerasia Basin (Fig. 2). The deep water basin was created by the rotation of Alaska-Chukotka away from the Canadian Arctic Margin. The Canada Basin is underlain by thick Early Cretaceous to Holocene clastic strata that lie on highly attenuated continental or oceanic crust, but the Jurassic and earliest Cretaceous history remains poorly constrained. Data is limited to seismic collected during Canada's UNCLOS program, a few sea floor samples, and potential field geophysics (Fig. 3). No wells have been drilled in this assessment area.

The Canada Basin extends across the floor of the Arctic Ocean to the Northwind Ridge and Alpha Ridge. Canada's 200 nautical mile limit and Extended Continental Shelf boundaries lie within the Canada Basin. The geological boundary rather than the political boundary (200 nautical mile limit) is used in most assessments.

Petroleum systems elements that could result in hydrocarbon accumulations are: potential oil and gas prone Upper Cretaceous to Paleogene source rocks deposited in the deep basin; reservoirs in fine grained turbidite sands; traps in fault blocks and detachment folds related to rifting and deformation pushing north from Alaska, with hydrocarbon generation from the Late Eocene to Early Miocene.

Arctic Margin. This assessment area occupies much of the marine shelf offshore the western Arctic Islands (Fig. 2). It extends west from the inflection point, where Mesozoic-Cenozoic strata begin to increase rapidly in thickness, to the toe of the continental slope. The rift margin formed by the rotation of Alaska-Chukotka away from Canada in Jurassic-Cretaceous time, and is underlain by Jurassic to Cretaceous synrift clastic strata, and thick fluvial, deltaic and marine units of Cretaceous to Holocene age. Volcanic units related to the High Arctic Large Igneous Province are present in the far north. There is very little data other than seismic adjacent to Banks Island in the south, potential field geophysics along the margin, and field mapping and drilling on the adjacent Arctic Islands (Fig. 3). There has been no drilling and no hydrocarbon discoveries.

Petroleum systems elements that could result in hydrocarbon accumulations are: potential Jurassic to Paleocene source rocks, with the older marine source rocks more likely to be oil prone, and the younger terrestrial source rocks gas prone; reservoirs in Cenozoic fluvial to shelf sandstones; and hydrocarbon generation in the Cenozoic, synchronous with or post-dating, trap formation.

Banks and Eglinton Basins. These grabens are south of the Sverdrup Basin and east of the Arctic Margin (Fig. 2). They contain synrift clastic stratigraphic units that are similar to the younger part of the Sverdrup Basin. Previous assessments have variously included these basins in the Sverdrup Basin, as part of the Arctic Margin, or as part of the Stable Platform.

Eleven wells penetrate these basins, nine on Banks Island and two on Eglinton Island. There are seismic grids of varying quality from the 1970s and 1980s.

Two potential petroleum provinces are present in these basins. Silurian and Devonian petroleum systems elements that could result in hydrocarbon accumulations are Silurian and Devonian organic-rich shales as potential source rocks with Devonian reefs and clastic strata as reservoirs. Peak generation would have been during the Late Devonian. Extensive uplift and erosion during late Paleozoic and early Mesozoic times likely reduced the hydrocarbon potential of the lower Paleozoic succession. Jurassic to Cenozoic petroleum systems elements that could result in hydrocarbon accumulations are Jurassic and Cretaceous oil-prone marine source rocks and Cenozoic gas-prone terrestrial source rocks, Cretaceous and Paleocene sandstone reservoirs, and traps developed along tilted fault blocks or stratigraphic traps. The level of thermal maturity is low, reducing the chance of widespread hydrocarbon generation in Mesozoic strata in these basins.

Sverdrup Basin. An intracontinental basin, in part back arc and in part sag, underlies the northern Arctic Islands (Fig. 2). The Sverdrup Basin is underlain by thick Carboniferous to Cretaceous carbonate, evaporite, and clastic strata. There is an extensive seismic grid (Fig. 3), about 125 drill holes and 19 gas or oil discoveries (Fig. 4) including the two largest conventional gas fields in Canada, Drake and Hecla.

Petroleum systems elements that result in hydrocarbon accumulations are rich, oil-prone Triassic source rocks; reservoirs in Jurassic fluvial to shelf sandstones overlain by a Jurassic shale seal. Discoveries were within salt-cored structural anticlines, but potential of stratigraphic traps and deeper petroleum systems have not been tested. Hydrocarbon generation peaked in the Cretaceous to Paleogene.

High Arctic Basins – Lincoln Sea, Lomonosov Ridge, Alpha Ridge, and Makarov Basin. Offshore areas north of Ellesmere, Axel Heiberg and Ellef Ringnes islands encompass parts of the offshore northeastern Arctic Margin Basin, Ellesmere Shelf, Lincoln Sea Basin, Lomonosov Ridge, Alpha Ridge, Canada Basin, and Makarov Basin (Fig. 2). The Arctic Margin and Canada Basin are considered as separate assessment areas in this report. The Ellesmere Shelf and Alpha Ridge are underlain by igneous or metamorphic rocks with virtually no hydrocarbon potential. The Lincoln Sea Basin, Lomonosov Ridge, and adjacent Makarov Basin are included in this assessment area. There is no drilling and only a minor amount of reflection seismic data (Ice Island), plus eight refraction seismic lines (Fig. 3). The boundaries between assessment areas are largely based on potential field geophysical maps and refraction seismic data, and inferences about stratigraphy and petroleum systems are based on data from surrounding basins and other global analogues.

Petroleum systems elements that are speculated to result in hydrocarbon accumulations are of Triassic to Cenozoic oil- and gas-prone source rocks; reservoirs in fluvial to shelf sandstones of Jurassic age (Lincoln Sea), in fluvial to shelf sandstones of Cretaceous to Cenozoic age (Lincoln Sea), and deep water turbidite sands (Makarov Basin). Traps are most likely to be stratigraphic, possibly with salt-cored structures in the Lincoln Sea. Hydrocarbon generation likely peaked in the Cretaceous to Paleogene.

Baffin Margin. This margin extends from the coast of Baffin Island to the toe of the continental slope, and includes the entrances to Jones, Lancaster, and Cumberland sounds (Fig. 2). The rifted continental margin was created by the movement of Greenland away from Labrador and Baffin Island. The shelf is underlain by a thick accumulation of Cretaceous to Holocene clastic strata and large deltas prograded from the mouths of Lancaster and Jones sounds. There is one short research drill hole in the northern margin, and several exploration drill holes and gas discoveries in the southern margin. The area is covered by extensive seismic and potential field grids.

Petroleum systems elements that could result in hydrocarbon accumulations are: potential Ordovician oil-prone, Cretaceous oil- and gas-prone, and possibly Paleogene gas-prone source rocks; reservoirs in Upper Cretaceous and Paleogene marginal marine to slope and fan sandstones. Traps are likely present as tilted fault blocks in grabens and as stratigraphic traps where sandstone bodies transition into shale at a facies change. Peak hydrocarbon generation occurred in the Late Cretaceous or Paleogene.

Foxe Basin. Intracontinental sag basin with Ordovician to Silurian carbonate strata that lies between Baffin Island and Melville Peninsula (Fig. 2). Data is limited to one drill hole and potential field data. There is no seismic in Foxe Basin.

Petroleum systems elements that could result in hydrocarbon accumulations are: Ordovician oil-prone source rocks; reservoirs in Ordovician to Silurian carbonates; with hydrocarbon generation in the Devonian.

Franklinian Margin. Lower Paleozoic strata preserved on the Neoproterozoic to Late Devonian margin of North America. These include rift, passive margin, and foreland basin carbonate, clastic and evaporite strata. Sixty-eight boreholes intersect the lower Paleozoic succession Four wells had oil shows or discoveries, 3 had gas shows. One small oil field, at Bent Horn on Cameron Island, was discovered in a fractured Devonian reef. Seismic was acquired over lower Paleozoic strata between 1968 and 1979 with about 1250 lines totaling 34,500 line kilometers. The data is extremely variable in quality and record length.

Petroleum systems elements that could result in hydrocarbon accumulations are of Ordovician and Silurian oil-prone source rocks, carbonate reservoirs in Silurian and Devonian reef traps, and clastic reservoirs in large-scale folds. Hydrocarbon generation was during Devonian time over most of the area, but as young as Cretaceous near the northern contact of the Franklinian Margin with the overlying Sverdrup Basin.

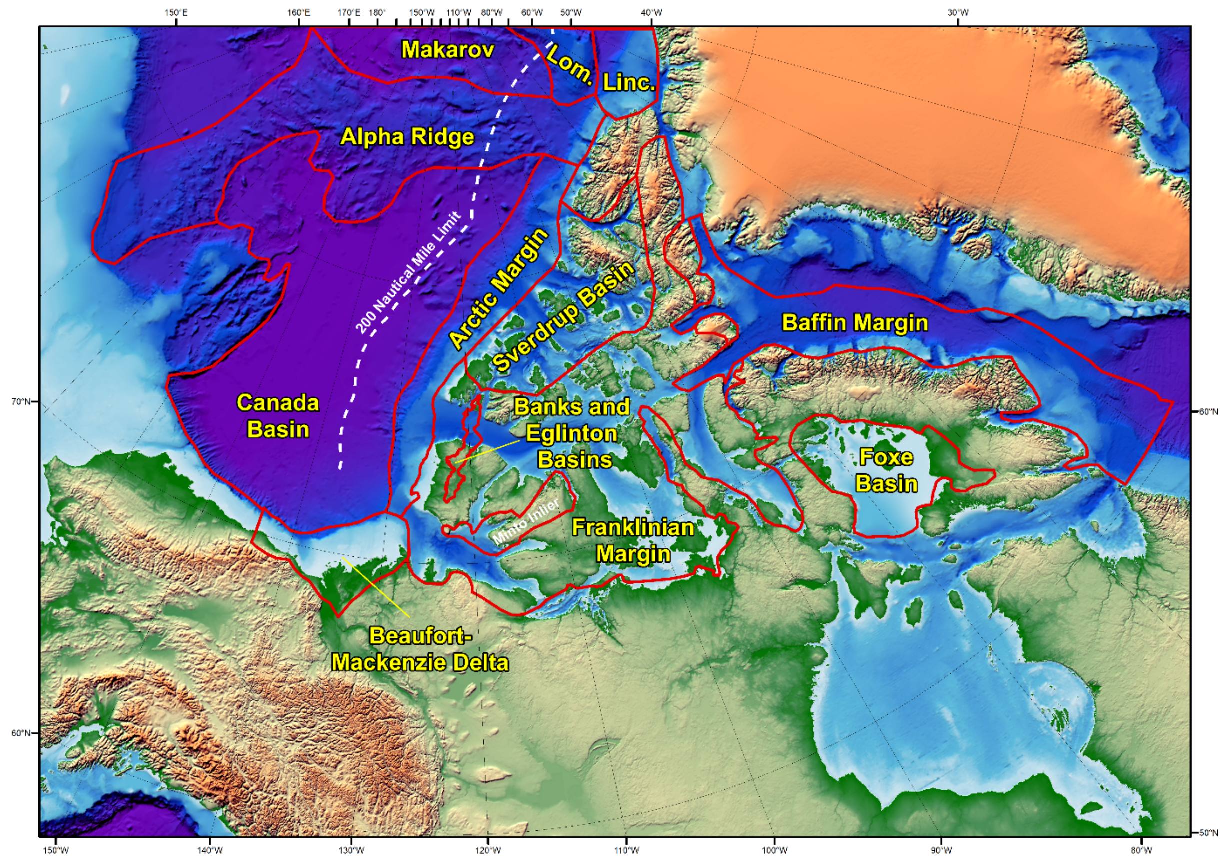


Figure 2. Location of assessment areas based on best current geological knowledge. Resource assessment reports by different authors use slightly different boundaries as shown in Figure 6. Minto Inlier underlain by Proterozoic strata.

Seismic and Drill Data

Seismic data were collected extensively between 1968 and 1984 by numerous operators, and then again in the 2000s by ION Geophysical Inc. in the Beaufort Sea and Banks shelf. Seismic collected in the 1970s is generally poorer quality due to short streamer length (which leads to more problems with multiple reflections off the sea floor or base of permafrost), use of dynamite as a source (which has a wide frequency range and leads to a noisier image), short recording times (which limits the depth interpretation), and lower quality of the recording equipment. Data collected in the 2000s used long streamers, tuned sources, and had very long recording times. There also exists 3D seismic surveys in the Beaufort-Mackenzie Delta region that has not been used for the existing published resource estimates.

There are approximately 263 boreholes (about 92 offshore) in the Mackenzie-Beaufort area and about 180 boreholes in the Arctic Islands, of which about 133 are in the Sverdrup Basin (47 offshore) (Fig. 4). There is slight variation in number of wells because of the way deviated legs and very short, junked holes are reported. The Baffin Margin has two drill holes, both at the very southern end, plus one short research drill hole offshore central Baffin Island. The first exploration boreholes were drilled in 1962, with the last borehole in the Arctic Islands drilled in 1986 and in the Mackenzie-Beaufort region in 2009 (Fig. 5). The deepest boreholes are about 5.5 km deep. The deeper parts of the Sverdrup Basin and the Mackenzie Delta were not penetrated by drilling (Fig. 5). The geology and hydrocarbon potential of the deeper parts of each basin is assessed strictly on seismic data, however the shorter recording times of seismic in the 1970s and 1980s means that the base of the Sverdrup Basin is not imaged in the central parts of the basin.

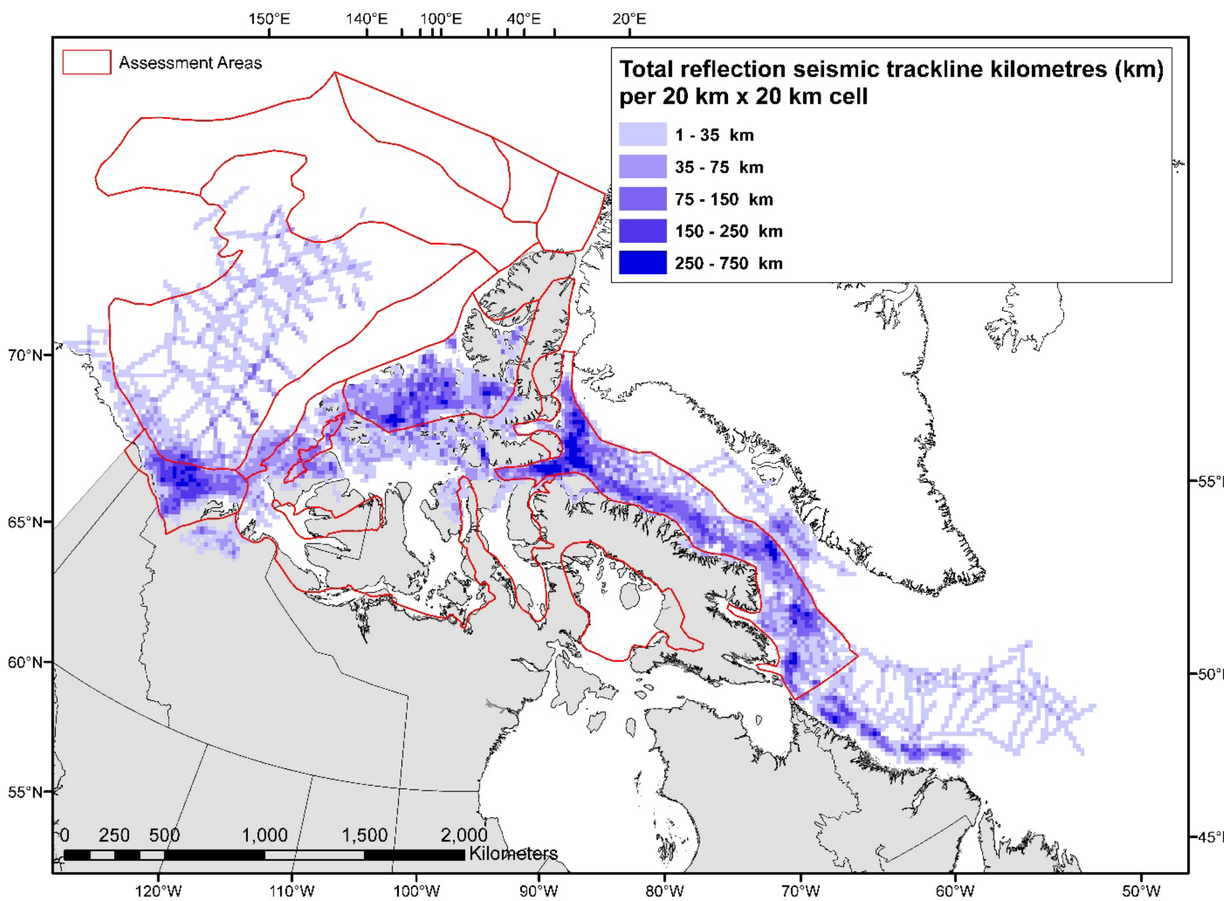


Figure 3. Density of seismic lines in the Canadian Arctic. The colours denote the line kilometres of seismic within each 20x20 km cell. Refer to Fig.2 for assessment area names.

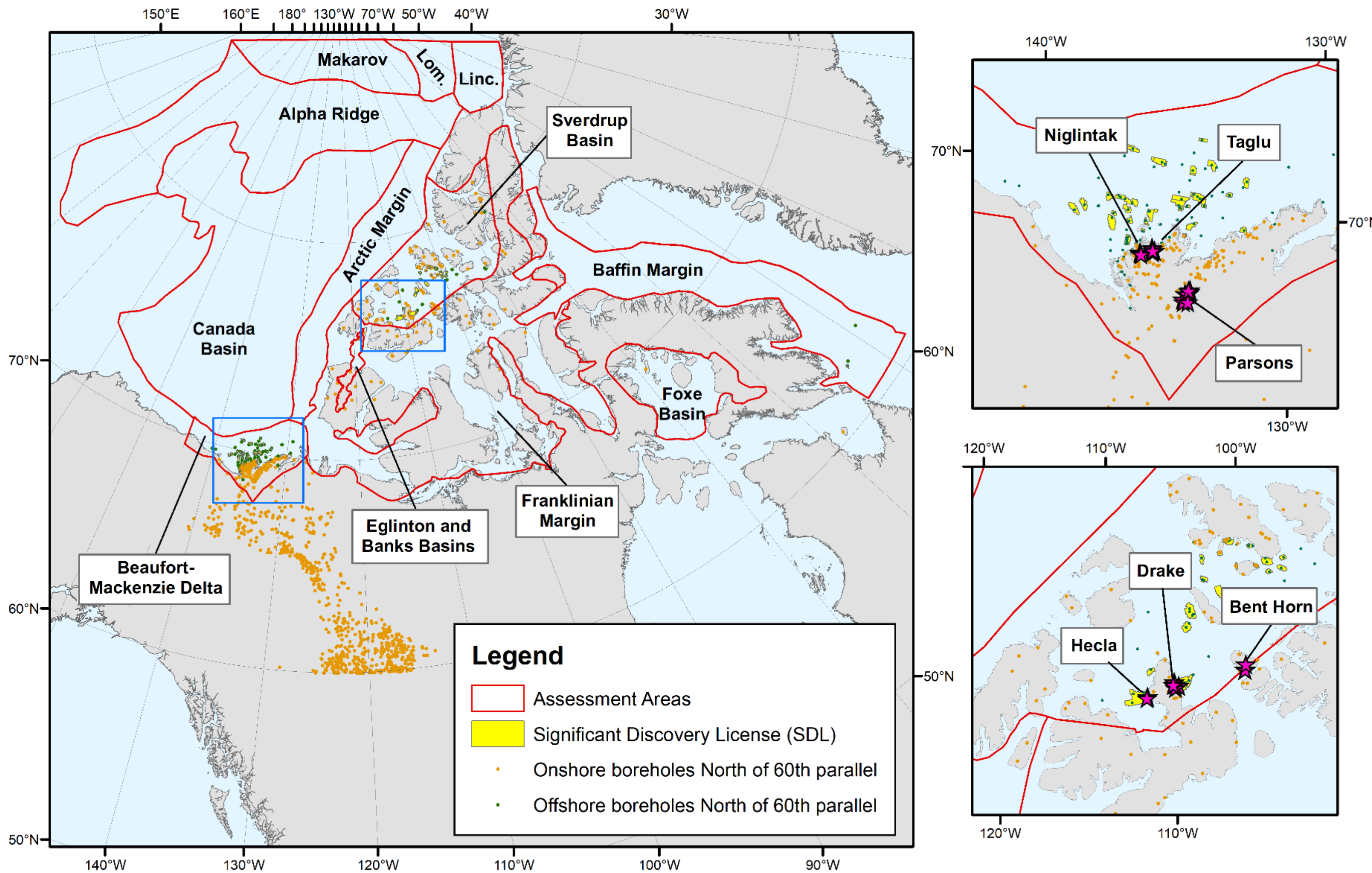


Figure 4. Location of exploration boreholes and significant discovery licences in the Canadian Arctic. Red stars show fields discussed in text.

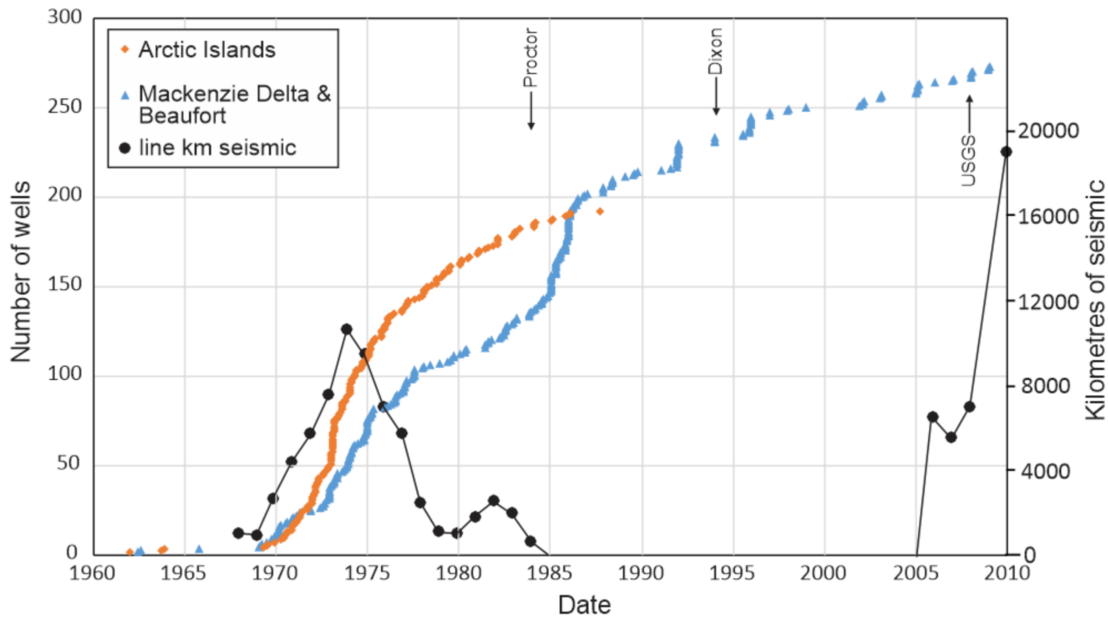


Figure. 5. Cumulative number of boreholes drilled in the Canadian Arctic Islands (orange diamonds) and Mackenzie Delta-Beaufort Sea regions (blue triangles). Average length of boreholes in the Canadian Arctic was about 2.5 km, whereas boreholes in the Mackenzie Delta-Beaufort Sea region average about 3.0 km. Interpretation of petroleum systems elements below these depths are based primarily on seismic interpretation and have less geological control. Estimates of resources at deeper levels have greater uncertainty due to the lack of direct sampling.

The line kilometres of 2D seismic by year are shown in black, not including 3D surveys in the Beaufort Sea acquired in the 2000s. Publication dates of important assessments by Proctor, Dixon and USGS shown, but they may not have had access to all data acquired to that point.

Historical Resource Assessments

Forty-nine assessments were considered for this report. These are listed in Table 1, where they are catalogued by region (number) and chronology (letter), and the assessment areas shown in Figure 6. The method and reporting used in each resource assessment is summarized in Table 2.

Appendix A1 gives a brief description of the main methodology types that are used for resource assessments, and Appendix A2 lists some of the pitfalls and concerns in using historical resource assessments. Appendix B gives a more complete review of individual resource assessments, including what is known about the inputs and methodology.

Resource Assessments through the Years

There are three distinct eras in which resource assessments and methodologies have been performed in the Canadian Arctic: pre-1980 assessments that relied on rudimentary software and computing power and limited geological data; the 1984 national assessment (ref. 1a, Proctor) that relied on statistically robust software and had access to much of the data produced in the 1968-1986 exploration boom in the North; and post-1984 assessments that use increasingly sophisticated software and geological knowledge.

Over time, there has been continued improvements to geological knowledge, available data, and modelling methodologies which leads to improved resource potential reporting. There are four common methods used for reporting resource potential: volumetric yield, probabilistic / Monte Carlo, discovery process, and prospectivity mapping (Appendix A2).

Critical evaluation of the resource assessments using present day criteria and knowledge identifies clear pitfalls and concerns in using single historical resource assessment. Common reoccurring issues in understanding historical resource assessments include transparency, oil versus gas ratio, recovery factors, past geological play definitions, software limitations, herding, and incorrect inputs or analogues. These are further defined in Appendix A3. These pitfalls and concerns should not be attributed to the authors of the resource assessments or the quality of the report as each report is representative of the state of knowledge at the time of publication. These concerns are documented here to raise awareness about the limitations of using historical resource assessments for evaluation purposes.

Resource Assessment Reporting

Quantitative resource assessment values are statistically derived. The potential cases they present are based on input parameters that have a standard deviation and probability distribution. The resulting resource assessment will have its own probability distribution rather than a single value. The way that this predicted range of resource size is reported varies. Some assessments give mean values, others report the assessed value that has a 50% chance of being present (P50). P50 and mean are rarely the same because the expected field sizes have a skewed distribution. Mean and P50 are only the same if the distribution is normally distributed. Some reports also give the extreme ends of the distribution, P95 is the value that has a 95% chance of being present, whereas P5 is the resource size that only has a 5% chance of being present.

The resource values are not always reported the same way and can represent recoverable (how much oil and gas can be extracted), in-place (how much oil and gas remains in the ground), or ultimate resource (including produced, discovered, and undiscovered). Caution is required when comparing each historical resource assessment to ensure that the same reporting standards are used.

Table 1. Resource assessments for Arctic Canada 1973-2020.

	REPORT	AUTHOR(S)	YEAR	SOURCE
Pre- 1980 Industry Assessments				
	Canadian Arctic Islands. In: The Future Petroleum Provinces of Canada - their Geology and Potential	Drummond K.J.	1973	Canadian Society of Petroleum Geologists, Memoir 1, p. 443-472
	Beaufort Sea. In: The Future Petroleum Provinces of Canada - their Geology and Potential	Lerand, M.	1973	Canadian Society of Petroleum Geologists, Memoir 1, p. 315-386
	Canadian Arctic Islands	Rudkin, R.A.	1973	Petroleum Potential of Arctic Canada. American Institute of Mining, Metallurgical and Petroleum Engineers, Paper SPE 4384, p. 79-85
Pre- 1980 Geological Survey of Canada Assessments				
	1973 Evaluation of Ultimate Recoverable Potential for Oil and Gas. Geological Survey of Canada, Internal Memo 208-1-1-1-A	Geological Survey of Canada	1973	Geological Survey of Canada, Internal Memo 208-1-1-1-A
	Conventional Petroleum Resources of Canada 1974 estimate. A report to the EMR Petroleum Resources Committee by the subcommittee on Geological Potential	Geological Survey of Canada	1975	A report to the EMR Petroleum Resources Committee by the subcommittee on Geological Potential.
	Oil and Natural Gas Resources of Canada 1976. Energy Mines and Resources Canada Report EP77-1	Geological Survey of Canada	1976	Oil and Natural Gas Resources of Canada. Energy Mines and Resources Canada.
	1979 Evaluation of Ultimate Recoverable Potential for Oil and Gas	Geological Survey of Canada	1979	Geological Survey of Canada, Internal Files

Table 1. (continued)

LIST #	REPORT	AUTHOR(S)	YEAR	SOURCE
Relevant publications including and post- Proctor 1983				
All regions				
1a.	Oil and natural gas resources of Canada	Procter, R.M., Taylor, G.C., and Wade, J.A.	1984	Geological Survey of Canada, Paper 83-31, 59 p.
1a. i.	Petroleum Resources of the Arctic Islands	Embry, A.F., Osadetz, K.G., Smith, D.R., Taylor, G.C., and Procter, R.M.	1983	Geological Survey of Canada, Panel Report 83-01, 40 p.
1b.	Petroleum Exploration in Northern Canada: A guide to oil and gas exploration and potential	Northern Oil and Gas Directorate	1995	Indian and Northern Affairs Canada
1c. i.	Natural Gas Potential in Canada 1997	The Canadian Gas Potential Committee	1997	The Canadian Gas Potential Committee
1c. ii.	Natural Gas Potential in Canada 2001	The Canadian Gas Potential Committee	2001	The Canadian Gas Potential Committee
1c. iii.	Natural Gas Potential in Canada 2005	The Canadian Gas Potential Committee	2005	The Canadian Gas Potential Committee V1-V4
1d.	Circum-arctic resource appraisal: Estimates of undiscovered oil and gas north of the arctic circle	United States Geological Survey (USGS)	2008	USGS Fact sheet 2008-3049 / Professional Paper Chapter A. see also Gautier, D.L., Bird, K.J., Charpentier, R.R., Grantz, A., Houseknecht, D.W., Klett, T.R., Moore, T., Pitman, J., Schenk, C., Schuenemeyer, J., Sørensen, K., Tennyson, M., Valin, Z., Wandrey, C.J., 2009. Assessment of undiscovered oil and gas in the arctic; Science, 324 (5931), p. 1175–1179.
1e.	Petroleum and minerals management directorate - Prospectivity map	Indigenous and Northern Affairs Canada	2008	Indian and Northern Affairs Canada
1f.	Northern Canada distribution of ultimate oil and gas resources	Drummond K.J.	2009	Indian and Northern Affairs Canada
1g.	Assessment of yet-to-find petroleum resources of the Canadian Arctic	Chen, Z., Dietrich, J. Hannigan, P., Osadetz, K., Dewing, K., Brent, T., and Issler, D.	2013	American Association of Petroleum Geologists (AAPG) conference
1h.	Circum-Arctic Resource Appraisal	United States Geological Survey (USGS)	2016	United States Geological Survey (USGS)
1i.	Hydrocarbon potential map of the Canadian Arctic Archipelago and northern offshore areas	Dewing, K.E., Lister, C.J., Kung, L.E., Atkinson, E.A., King H.M.	2022	Geological Survey of Canada Open File 8884

LIST #	REPORT	AUTHOR(S)	YEAR	SOURCE
no copy	Canada's Conventional Natural Gas Resources, A Status Report	National Energy Board (NEB)	2004	National Energy Board (NEB)
Beaufort Sea - Mackenzie Delta				
2a.	Petroleum Resources of the Mackenzie Delta - Beaufort Sea	Dietrich, J.R., Dixon, J., Procter, R.M., Snowdon,L.R., Taylor, G.C., and Ward, W.J.	1983	Geological Survey of Canada, Panel Report 83-03, 50 p.
2b.	Petroleum resources of the Mackenzie Delta and Beaufort Sea	Dixon, J., G.R. Morrel, J. R. Dietrich, R.M. Procter, and G.C. Taylor	1988	Geological Survey of Canada, Open File 1926, 80 p.
2c.	Reason for Decision GH-10-88	National Energy Board (NEB)	1989	National Energy Board (NEB)
2d.	Petroleum resources of the Mackenzie Delta and Beaufort Sea	Dixon, J., G.R. Morrel, J. R. Dietrich, G.C. Taylor, R.M. Procter, R.F. Conn, S.M. Dallaire, and Christie, J. A.	1994	Geological Survey of Canada, Bulletin 474, 52 p.
2e.	Probabilistic estimate of hydrocarbon volumes in the Mackenzie Delta and Beaufort Sea discoveries	National Energy Board (NEB)	1998	National Energy Board (NEB)
2f.	Petroleum Resource Assessment of the Yukon North Coast, Yukon Territory, Canada	Hannigan, P.K.	2001	Yukon Economic Development
2g.	Natural gas resource assessments and deliverability forecasts, Beaufort-Mackenzie and selected northern Canadian basins	Chipperfield, J.L., O'Blenes, M.J., and Drummond, K.J.	2005	Sproule. Downloaded from CER-REC.GC.CA
2h.	Assessment of undiscovered oil and gas resources of the Mackenzie Delta province, North America, 2004	United States Geological Survey (USGS)	2006	Henry, M.E., Ahlbrandt, T.S., Charpentier, R.R., Gautier, D.L., Klett, T.R., Pollastro, R.M., Schenk, C.J, and Ulmishek, G.F., 2004. Assessment of Undiscovered Oil and Gas Resources of the Mackenzie Delta Province, North America; United States Geological Survey, Fact Sheet FS-2006- 3002, 7 p.
2i.	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 Area	Osadetz, K.G., Dixon, J., Dietrich, J.R., Snowdon, L. R., Dallimore, S.R., and Majorowicz, J. A.	2005	Geological Survey of Canada, Open File 4828
2j.	A27695-3 NEB - Reasons for Decision - Mackenzie Gas Project - GH-1-2004, Volume 2 appendix D	National Energy Board (NEB)	2004	National Energy Board (NEB)

Table 1. (continued)

LIST #	REPORT	AUTHORS	YEAR	SOURCE
2k.	Assessment of discovered conventional petroleum resources in the Northwest Territories and Beaufort Sea	National Energy Board (NEB)	2014	National Energy Board (NEB)
2l.	Discovered conventional petroleum resources in the Northwest Territories and Beaufort Sea	Irwin, D. and Fiess, K.M.	2019	NWT Open Report 2019-15
Canada Basin				
3a.	Geology and Assessment of Undiscovered Oil and Gas Resources of the Amerasia Basin Province, 2008	Houseknecht, D.W., Bird, K. J., and Garrity, C.P.	2020	Chapter BB of The 2008 Circum-Arctic Resource Appraisal, Supersedes Scientific Investigations Report 2012-5146
3b.	Oil and gas resource potential in the deep-water Canada Basin, Arctic Ocean	Dietrich, J. R., Chen, Z., Hannigan, P.K, Hu K., and Yu, X.	2018	Geological Survey of Canada Open File 8355, 28 p., ed. Rev.
Arctic Margin				
4a.	Petroleum Resource Potential of the Rifted Margin of the Beaufort-Mackenzie Basin, Arctic Canada	Chen, Z., Dietrich, J., and Liu, Y.	2011	Polar Petroleum Potential Conference & Exhibition, AAPG Article #90130
Sverdrup Basin				
5a.	Reserve/resource estimate sheets (data input for Chen et al. 2000)	Panarctic Oils	~1985	Panarctic Oils
5b.	Petroleum potential in western Sverdrup Basin	Chen, Z., Osadetz, K.G., Embry, A.F., Gao, H., and Hannigan, P.K.	2000	Bulletin of Canadian Petroleum Geology, v. 48, no. 4, p.323-338
5c.	An object-based model for predicting the locations of undiscovered oil and gas resources, western Sverdrup Basin, Canada.	Chen, Z., Osadetz, K.G., Gao, H., and Hannigan, P.K.	2004	Marine and Petroleum Geology, v. 21, no. 6, p. 767-777
5d.	High Arctic Hydrocarbon Potential - heat map	Northern Oil and Gas Branch	2010	Northern Oil and Gas Branch
5e.	Using discovery process and accumulation volumetric models to improve petroleum resource assessment in Sverdrup Basin, Canadian Arctic Archipelago, Chapter 39	Chen, Z. and Osadetz, K.G.	2011	Geological Society, London, Memoirs, v. 35, no.1, p. 581-593
5f.	Geological risk evaluation using the Support Vector Machine with examples from the late Triassic-early Jurassic structural play western Sverdrup Basin, Canadian Arctic Archipelago	Chen, Z., Liu, Y., and Osadetz, K.G.	2013	Bulletin of Canadian Petroleum Geology, v. 60, no. 3, p. 142-157
5g.	Geology and Assessment of Undiscovered Oil and Gas Resources of the Sverdrup Basin Province, Arctic, Canada, 2008	Tennyson, M.E. and Pitman, J.K.	2020	Chapter I of The 2008 Circum-Arctic Resource Appraisal, Professional Paper 1824

Table 1. (continued)

LIST #	REPORT	AUTHORS	YEAR	SOURCE
High Arctic Basins				
6a.	Chapter 44 Geology and petroleum potential of the Lincoln Sea Basin, offshore North Greenland	Sørensen, K., Gautier, D., Pitman, J. Jackson, H. R., and Dahl-Jensen, T.	2011	Geological Society, London, Memoirs, Volume 35, p. 673–684
6b.	Chapter 49, A first look at the petroleum geology of the Lomonosov Ridge microcontinent, Arctic Ocean	Moore, T.E., Grantz, A., Pitman, J.K., and Brown, P.J.	2011	Geological Society, London, Memoirs, Volume 35, p. 751–769
6c.	Geology and Assessment of Undiscovered Oil and Gas Resources of the Lomonosov-Makarov Province, 2008	Moore, T.E., Bird, K.J., and Pitman, J.K.	2019	Chapter CC of Moore, T.E., and Gautier, D.L., eds., The 2008 Circum-Arctic Resource Appraisal: U.S. Geological Survey Professional Paper 1824, 43 p.
6d.	High Arctic basins petroleum potential	C.J. Lister, E.A. Atkinson, K.E. Dewing, H.M. King, L.E. Kung, and T. Hadlari	2022	Geological Survey of Canada Open File 8897
Baffin Margin				
7a.	Lancaster Sound Regional Study - Map 4.1	Indian and Northern Affairs Canada	1980	Indian and Northern Affairs Canada
7b.	Petroleum exploration offshore southern Baffin Island, northern Labrador Sea, Canada	Klose, G.W., Malterre, E., McMillan, N.J., and Zinkan, C.G.	1982	Canadian Society of Petroleum Geologists, Memoir 8, Arctic Geology and Geophysics, p. 233-244
7c.	Geology and Assessment of Undiscovered Oil and Gas Resources of the West Greenland-East Canada Province, 2008	Schenk, C.J., United States Geological Survey (USGS)	2017	Chapter J of The 2008 Circum-Arctic Resource Appraisal
7d.	Assessment of the conventional petroleum resource potential of Mesozoic and younger plays within the proposed National Marine Conservation area, Lancaster Sound, Nunavut	Brent, T.A., Chen, Z., Currie, L.D., and Osadetz, K.	2013	Geological Survey of Canada, Open File 6954, 54 p.
7e.	Qualitative assessment of petroleum potential in Lancaster Sound region, Nunavut	Atkinson, E.A., Fustic, M., Hanna, M.C., and Lister, C.J.	2017	Geological Survey of Canada, Open File 8297, 29 p.
Foxe Basin				
8a.	Qualitative petroleum resource assessment of Peel Sound, Bellot Strait, Gulf of Boothia, Fury and Hecla Strait, and Foxe Basin, Nunavut	Fustic, M, Hanna, M.C., Lister, C.J., King, H.M., Atkinson, E.A., and Dewing, K.E.	2018	Geological Survey of Canada, Open File 8439, 29 p.
Franklinian Margin				
9a.	F. Energy Resources and Assessment	Hannigan, P., Harrison, C.J., and Osadetz, K.	1999	Geological Survey of Canada, Open File 3714, F1-F96

Table 1. (continued)

Table 2. Method and reporting used in each resource assessment. AOI - area of interest. NGL – natural gas liquids

LIST #	METHODOLOGY	DEFINED AOI (No/Yes?)	OIL	GAS	NGL	ECONOMIC OVERLAY (No/Yes?)	REPORTED RESOURCE	ASSESSED RESOURCE
Relevant publications including and post- Proctor 1983								
All regions								
1a.	Type 2 - Monte Carlo / Probabilistic	Y	✓	✓		N	Ultimate recoverable, discovered resources	P5-P50-P95
1a. i.	Type 2 - Monte Carlo / Probabilistic	N	✓	✓		N	Ultimate recoverable	P5-P50-P95
1b.	Descriptive, petroleum systems	N				N	N/A	N/A
1c. i.	Type 3 - Discovery Process	Y		✓	✓	Y	Ultimate recoverable, discovered and undiscovered resources, endowment	Mean
1c. ii.	Type 3 - Discovery Process	Y		✓	✓	Y	Ultimate recoverable, discovered and undiscovered resources, endowment	Mean
1c. iii.	Type 3 - Discovery Process	Y		✓	✓	N	Ultimate recoverable, discovered and undiscovered resources, endowment	Mean
1d.	Type 2 - Monte Carlo / Probabilistic	Y	✓	✓	✓	N	Undiscovered resources	Mean
1e.	Type 4 – Prospectivity Map	Y	✓	✓		N	Low to high hydrocarbon potential	N/A
1f.	Type 2 - Monte Carlo / Probabilistic	N	✓	✓	✓	N	In-place, recoverable, and marketable (gas only) for discovered and undiscovered resources	P10-P90 for gas; P5-P95 for oil
1g.	Type 3 - Discovery Process	Y	✓	✓		N	Ultimate recoverable	Mean
1i.	Type 4 - Heat Map	Y	✓	✓		N	Low to high hydrocarbon potential	N/A
Beaufort - Mackenzie Delta								
2a.	Type 2 - Monte Carlo / Probabilistic	N	✓	✓		N	Ultimate recoverable, discovered resources	Mean
2b.	Type 3 - Discovery Process	Y	✓	✓		Y	Ultimate recoverable, discovered and undiscovered resources	Mean
2c.	Based on values published in 2b.	N		✓		N	Ultimate recoverable, discovered and undiscovered resources	Mean
2d.	Type 3 - Discovery Process	Y				Y	Ultimate recoverable, discovered resources	P25-P50-P75, mean
2e.	Type 2 - Monte Carlo / Probabilistic	N	✓	✓	✓	Y	Recoverable oil and condensate, marketable gas	P5-P50-P95 , mean
2f.	Type 2 - Monte Carlo / Probabilistic	Y	✓	✓		N	Undiscovered resources	Median
2g.	Type 2 - Monte Carlo / Probabilistic	Y	✓	✓	✓	N	Ultimate recoverable, discovered and undiscovered resources	Mean

LIST #	METHODOLOGY	DEFINED AOI (No/Yes?)	OIL	GAS	NGL	ECONOMIC OVERLAY (No/Yes?)	REPORTED RESOURCE	ASSESSED RESOURCE
Beaufort – Mackenzie Delta (cont.)								
2h.	Type 2 - Monte Carlo / Probabilistic	Y	✓	✓	✓	N	Undiscovered resources	P5-P50-P95, mean
2i.	Based on values published in 2b.	Y	✓	✓		Y	Ultimate recoverable, discovered resources	Mean
2j.	Type 2 - Monte Carlo / Probabilistic	N	✓	✓	✓	Y	In-place, recoverable, and marketable (gas only) for discovered resources	P10-P50-P90
2k.	Based on values published in 2i.	N	✓	✓	✓	N	Discovered initial marketable gas, recoverable oil	P50
Canada Basin								
3a.	Type 2 - Monte Carlo / Probabilistic	Y	✓	✓	✓	N	Undiscovered resources	F5-F50-F95, mean
3b.	Type 2 - Monte Carlo / Probabilistic	Y	✓	✓		N	Ultimate recoverable	P10-P50-P90
Arctic Margin								
4a.	Type 2 - Monte Carlo / Probabilistic	Y	✓	✓		N	In-place and recoverable resources	P10-P50-P90, mean
Sverdrup Basin								
5a.	Type 2 - Monte Carlo / Probabilistic	N	✓	✓		N	Discovered in-place and recoverable resources	Mean
5b.	Type 3 - Discovery Process	Y	✓	✓		N	In-place resources	Mean
5c.	Updated potential map to 5b. Chen 2000	Y	✓	✓		N	In-place resources	N/A
5d.	Type 4 - Heat Map	Y	✓	✓		N	Low to high hydrocarbon potential	N/A
5e.	Updated discovery process to 5b. and c.	Y	✓	✓		N	Discovered resources	Mean
5f.	Type 4 - Heat Map	Y	✓	✓		N	In-place resources	N/A
5g.	Type 2 - Monte Carlo / Probabilistic	Y	✓	✓	✓	N	Undiscovered resources	F5-F50-F95, mean
High Arctic Basins								
6a.	Type 2 - Monte Carlo / Probabilistic	Y	✓	✓	✓	N	Ultimate resources	Mean
6b.	Type 2 - Monte Carlo / Probabilistic	Y	✓	✓		N	Undiscovered resources	F5-F95, mean
6c.	Type 2 - Monte Carlo / Probabilistic	Y	✓	✓	✓	N	Undiscovered resources	F5-F50-F95, mean
6d.	Type 4 - Heat Map	Y				N	Undiscovered resources	P10-P50-P90, mean

Table 2. (continued). AOI - area of interest. NGL – natural gas liquids

LIST #	METHODOLOGY	DEFINED AOI (No/Yes?)	OIL	GAS	NGL	ECONOMIC OVERLAY (No/Yes?)	REPORTED RESOURCE	ASSESSED RESOURCE
Baffin Margin								
7a.	Type 4 - Low to high potential Map	Y	✓	✓		N	Low to high hydrocarbon potential	N/A
7b.	Type 2 - Monte Carlo / Probabilistic	N		✓		N	Recoverable gas	N/A
7c.	Type 2 - Monte Carlo / Probabilistic	Y	✓	✓	✓	N	Undiscovered resources	F5-F50-F95, mean
7d.	Type 2 - Monte Carlo / Probabilistic	Y	✓	✓		Y	Ultimate in-place and recoverable resources	P10-P50-P90
7e.	Type 4 - Prospectivity Map	Y	✓	✓		N	Low to high hydrocarbon potential	N/A
Foxe Basin								
8a.	Type 4 - Prospectivity Map	Y	✓	✓		N	Low to high hydrocarbon potential	N/A
Franklinian Margin								
9a.	Type 2 - Monte Carlo / Probabilistic	Y	✓	✓		N	In-place and recoverable resources	P10-P50-P90, mean

Table 2. (continued). AOI - area of interest. NGL – natural gas liquids

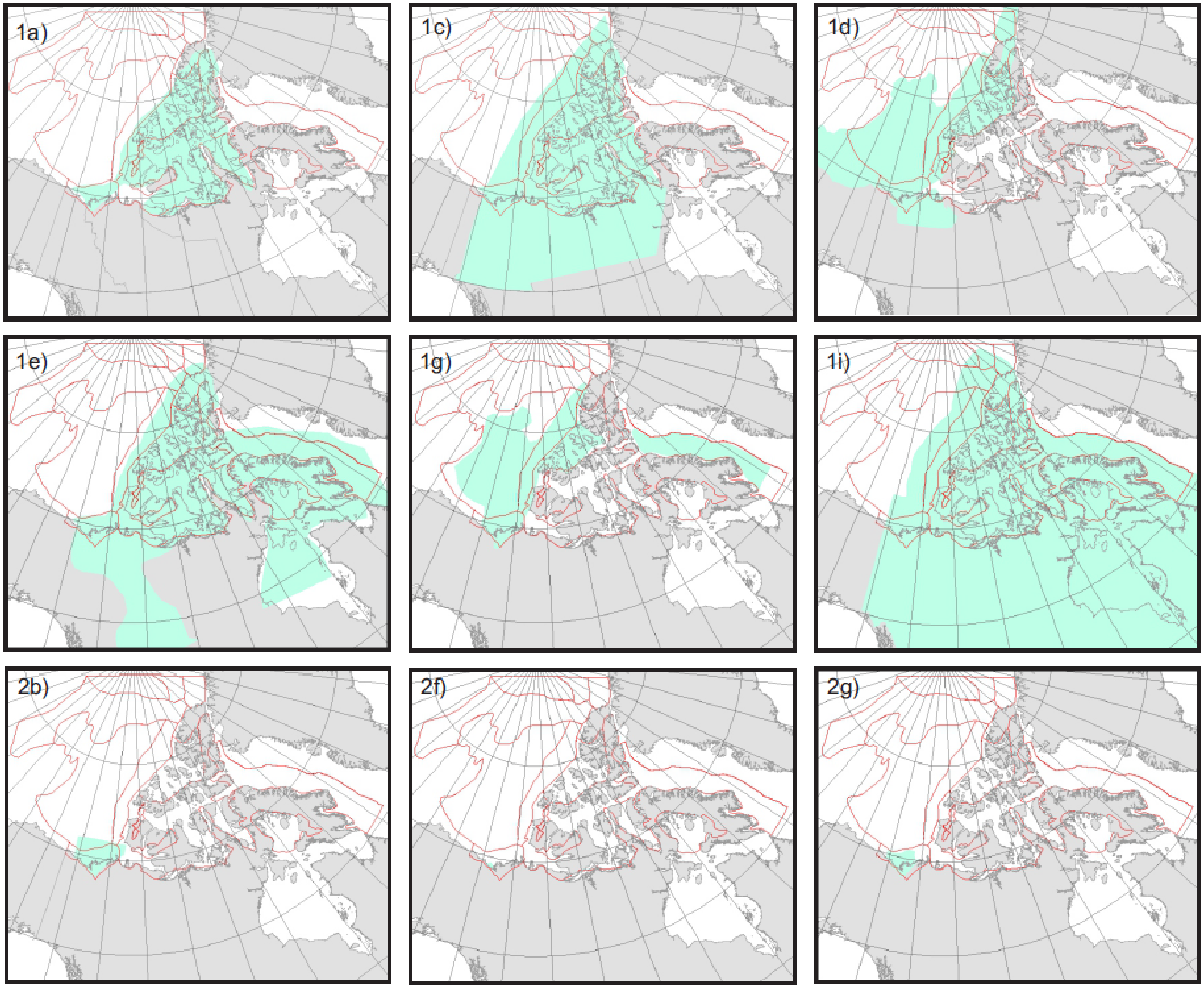


Figure 6. Assessment areas from relevant publications using the list number in Table 1 (green) relative to this report's geological boundaries (red).

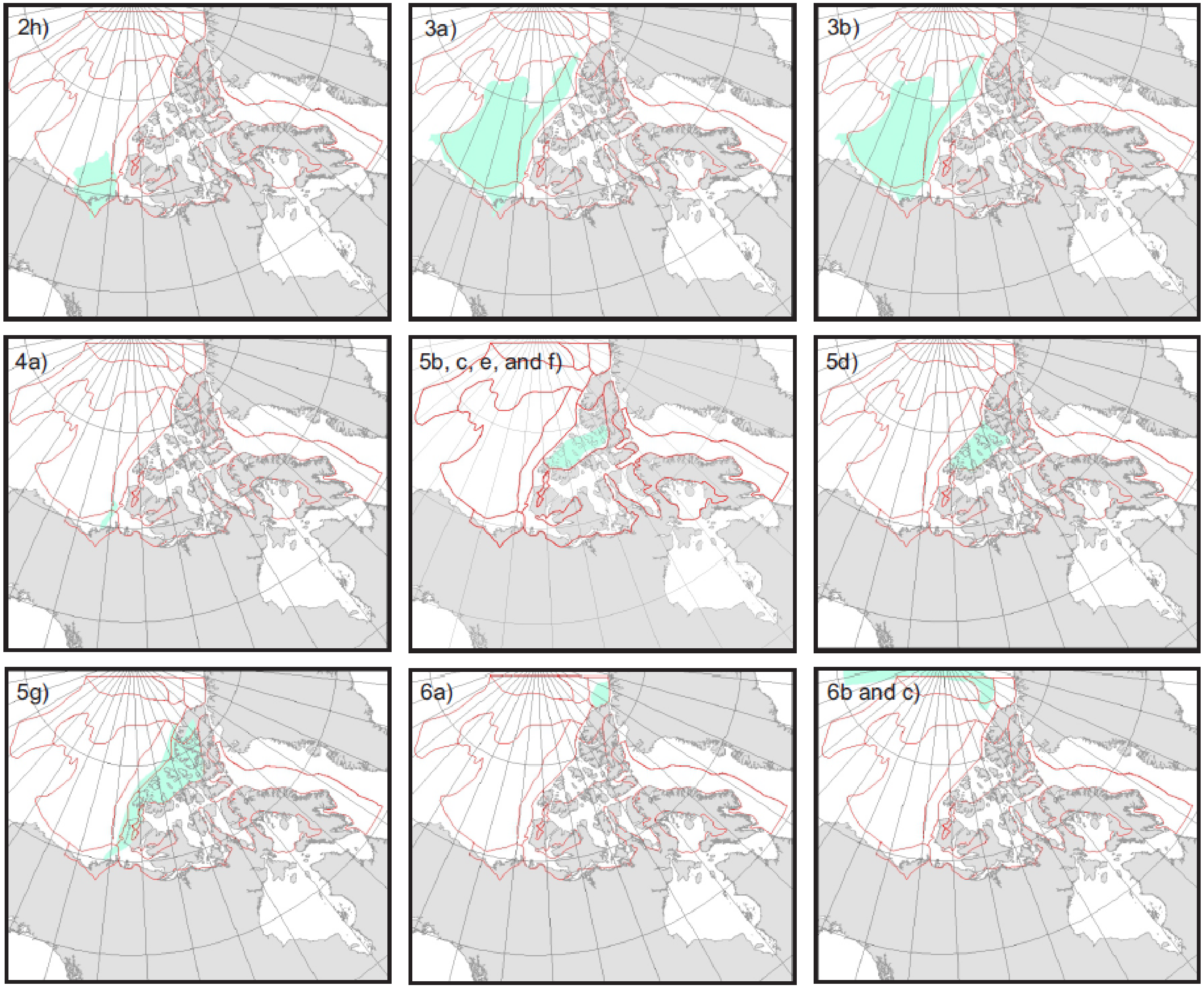


Figure 6. (continued)

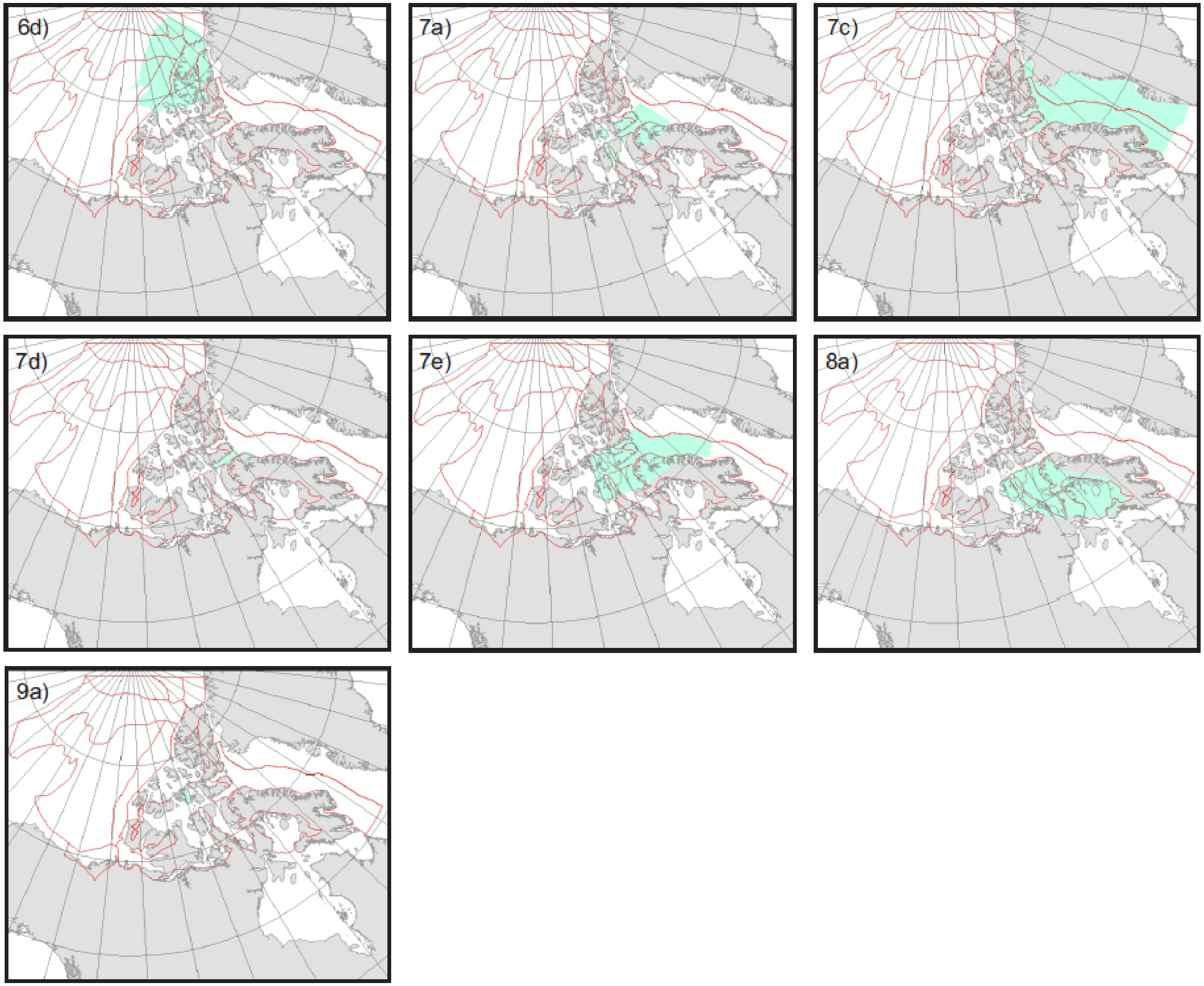


Figure 6. (continued)

Total Resource Potential Estimates for Assessment Areas

For each assessment area, a numeric range of **total mean resource potential for conventional systems** is given and derived from values reported in the resource assessments (Table 1). Only conventional resources are considered. This range does not include gas hydrates, unconventional/coal bed/tight oil or tight gas.

Reporting is standardized to a common mean recoverable resource in millions of barrels (Mbbls) or trillions of cubic feet (Tcf). For conversion factors used in this report, refer to Appendix B. In many ways, an *in situ* Oil-in-Place (OIP) or Gas-in-Place (GIP) is more useful because economic analysts could then apply their own recovery factors. However, recoverable resource is most commonly used in the existing resource assessments and converting to an *in situ* value introduces uncertainty because the recovery factors are generally not reported.

The amount of recoverable oil, recoverable gas, and recoverable natural gas liquids (if assessed separately) is given (Tables 3-13) for each resource assessment when available. The split between oil and gas is different in each assessment, so all values are converted to a 'Barrels of Oil Equivalent' (BOE), assuming 6000 cubic feet of gas is equivalent to one barrel of oil. This allows an easier comparison between the total amount of hydrocarbon predicted in each report and these values are plotted (Figures 7 – 12) to document changes in assessment over time.

Beaufort-Mackenzie Delta Region

There are nine assessments for the Beaufort-Mackenzie Delta area (Table 5 and Figure 9). The range of assessed recoverable hydrocarbon resource is from **15,178** to **28,882** million barrels of oil equivalent, for the five assessments that report both oil and gas.

The assessed recoverable natural gas is from **35.9** to **86.6** Tcf (trillion cubic feet). The lowest values are from the USGS (ref.3a; 2012), and the Canadian Gas Potential Committee (ref.1c.iii, 2005). There is no clear reason why the assessed values by the USGS (ref.3a; 2012) are lower than other assessments. The lower values may be due to their choice of analogue basins, or for methodological or software choices that cannot be determined from the published reports. The previous USGS assessment (ref.2h, 2004) reported much higher values that are very close to those of Chen (ref.1g, 2013). The low values from the Canadian Gas Potential Committee appear to be due to methodological choices such as the removal of some large predicted undiscovered fields, making this a very conservative estimate.

The reports of Dixon (ref.2d, 1994), NEB (ref.2c, 1988), Sproule (ref.2g, 2005), and Drummond (ref.1f, 2009) have very similar assessed recoverable gas resources of around 60 Tcf.

The assessed value of Chen (ref.1g, 2013) is higher for methodological reasons. Chen recognized that there are positive correlations between supposedly independent model inputs and employed a statistical tool (cupolas) to adjust for this. This results in a substantially higher assessed value. Chen's method and logic is well documented and similar methodology is being used in more recent resource assessment software.

The resource estimate is difficult to split into onshore-offshore components because the statistical methods employed for resource assessment are calibrated at the scale of a sedimentary basin. Because hydrocarbon fields are not randomly distributed in space, the assessed hydrocarbon resource should not be simply apportioned by area. Onshore-offshore splits are given in two reports and listed in Tables 14 and 15. The reliability of these estimates cannot be assessed from the details in these reports.

Beaufort-Mackenzie Delta Significant Discoveries

The aggregate resource related to significant discoveries in the Beaufort-Mackenzie Delta region is given in five reports. Some assessments include oil & natural gas whereas other assessments consider natural gas only (Table 3 and Figure 7).

The reported range of discovered recoverable hydrocarbon resource is from **2543** to **3899** million barrels of oil equivalent. This is from the five assessments that report both oil and natural gas. The assessment for discovered, recoverable natural gas ranges from **8.3** (Median value) to **14.71** Tcf (trillion cubic feet).

The National Energy Board (ref.2k, 2014) and Drummond (ref.1f, 2009) include the Paktoa oil discovery, made in 2006. Drummond only reported on gas, but the discovery of Paktoa led him to change the predicted oil:gas ratio, resulting in lower predicted gas volumes (i.e., some of the hydrocarbon predicted to be gas by Sproule Associates in 2005 was assigned to oil by Drummond). The higher value for discovered gas reserves reported by the NEB (ref.2j, 2014), and lower value reported by Canadian Gas Potential Committee (ref.1c.iii, 2005) appear to result from methodological differences, including the use of a truncated distribution by CGPC and the use of arbitrary 64 and 130 ha field areas by the NEB in the absence of seismic data.

The assessed discovered resource in an individual field changes over time, even after drilling has been completed (Table 4 and Figure 8). For example, the Taglu, Parsons, and Niglintgak fields were last drilled in the 1970s, yet the reported size of the recoverable resource at Taglu varies from 2144 to 3053 Bcf (billion cubic feet) between 1989 and 2014. The reports give no explanation for the 42% difference in field size between these reports. Changes in assessed resource likely come from changes in input parameters, such as area of closure from seismic interpretation, and methodological changes between assessments.

Table 3. Mean assessed amount of discovered oil and gas for Beaufort-Mackenzie region. Assessments after 2009 include the Paktoa oil discovery.

Report	Assessment Area	Reported Type	Discovered Recoverable oil (million barrels)	Discovered Recoverable gas (trillion cubic feet)	Discovered Recoverable NGL (million barrels)	Discovered Recoverable barrels of oil equivalent (millions BOE)
2k. NEB 2014	Beaufort Sea - Mackenzie Delta	Mean	918.45	14.71		3370
1f. Drummond 2009 Table 21 - 24	Beaufort Sea - Mackenzie Delta	Mean	864.2	11.15		2723
2g. Sproule 2005	Beaufort Sea - Mackenzie Delta	Mean	N/A	11.65		1942
1c.iii. CGPC 2005 Figure 3	Beaufort Sea - Mackenzie Delta	Mean	N/A	10.40		1733
2e. NEB 1998	Beaufort Sea - Mackenzie Delta	P50	1016.54	8.73	71.45	2543
2d. Dixon 1994	Beaufort Sea - Mackenzie Delta	Mean	1744	11.74		3701
1f. Drummond 2009 conversion from Dixon 1994 - Table 24	Beaufort Sea - Mackenzie Delta	Mean	1023	11.11		2875
2c. NEB 1989 from OF 1926	Beaufort Sea - Mackenzie Delta	Mean	N/A	11.65		1942
2a. OF 1926 1988	Beaufort Sea - Mackenzie Delta	Mean	1957	11.65		3899

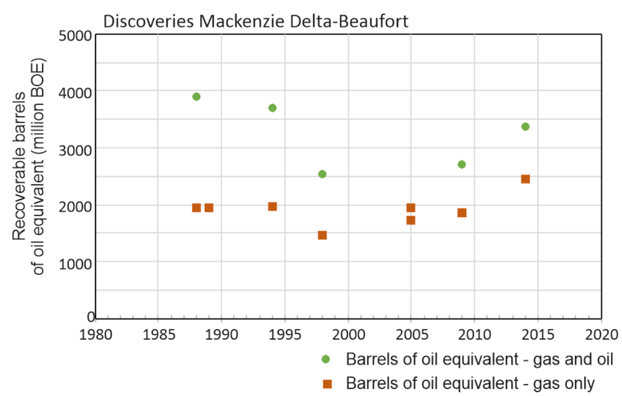


Figure 7. Mean assessed amount of discovered oil and gas for Beaufort Mackenzie region vs. year. Green dots include oil and gas as million BOE.

Table 4. Reported recoverable resource of the Taglu, Parsons Lake and Niglintgak fields, Beaufort-Mackenzie region. All values in billion cubic feet.

Report	**2c.** Industry	**2c.** NEB	**2e** NEB	**1c.** CGPC	**2i** Industry	**2f.** Sproule	**1f.** Drummond	**2i** NEB
Year	1989	1989	1998	2001	2004	2005	2009	2014
Field	Recoverable Established Reserves (Bcf)	Recoverable Established Reserves (Bcf)	Mean Marketable Gas (Bcf)	Recoverable gas (= 0.8 x Gas in Place) (Bcf)	Recoverable gas (Bcf)	Mean Recoverable gas (Bcf)	Mean Recoverable gas (Bcf)	Mean Recoverable gas (Bcf)
Taglu	3053	3053	2081	2166	2800	2900	2269	2144
Parsons	1825	1800	1259	1927	2300	2260	1798	1405
Niglintgak	971	971	484	566	950	910	510	725

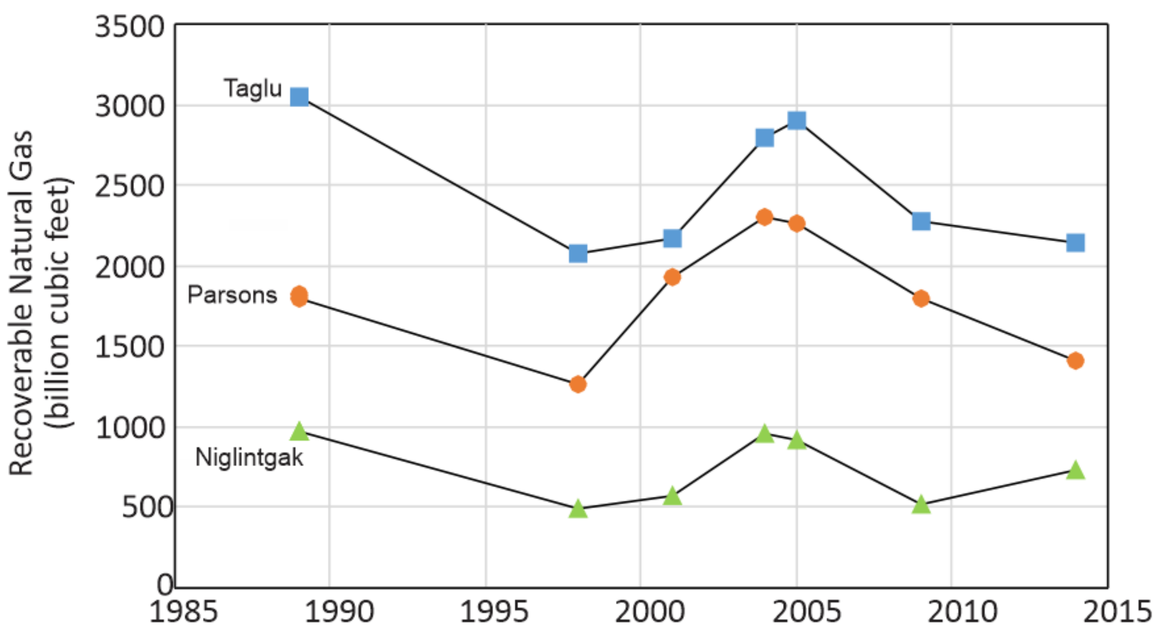


Figure 8. The variation in assessed amount of discovered recoverable gas for the Taglu, Parsons Lake, and Niglintgak fields by year.

Table 5. Ultimate mean recoverable hydrocarbon for the Beaufort-Mackenzie Delta region. The USGS reports undiscovered resource only, so the discovered resource reported by Dixon et al. (ref.2d; 1994) has been added to the USGS estimate (ref.3a, 2012). Hannigan (ref 2f; 2001) reports ultimate recoverable for only one offshore play, so the value is significantly smaller and not comparable with the others.

Report	Assessment Area	Reported Type	Ultimate Recoverable oil (million barrels)	Ultimate Recoverable gas (trillion cubic feet)	Recoverable Natural Gas Liquids (million barrels)	Recoverable barrels of oil equivalent (million BOE)
1g. Chen AAPG 2013	Beaufort Sea - Mackenzie Delta	Mean	10 500	86.6		24 933
3a. USGS CARA 2012	Canning - Mackenzie deformed margin	Undiscovered Mean	6380	35.90	338.5	16 403
1f. Drummond 2009 Table 11-12	Beaufort Sea - Mackenzie Delta	Mean	5041	60.82		15 178
2g. Sproule 2005	Beaufort Sea - Mackenzie Delta	Mean	N/A	60.49		10 082
1c.iii. CGPC 2005 Figure 3	Beaufort Sea - Mackenzie Delta Structural Plays	Mean	N/A	37.2		6362
2h. USGS 2004	Beaufort Sea - Mackenzie Delta	Mean	10 460	86.8	3989	28 882
2f. Hannigan 2001	Beaufort Sea - Mackenzie Delta (Herchel Play)	Undiscovered Median	218	0.10		235
2d. Dixon 1994	Beaufort Sea - Mackenzie Delta	Mean	7134	65.04		17 974
1f. Drummond 2009 conversion from Dixon 1994 - Table 24	Beaufort Sea - Mackenzie Delta	Mean	8196	60.82		18 333
2c. NEB 1989	Beaufort Sea - Mackenzie Delta	Mean	N/A	67.71		11 285
1a. Proctor 1984	South Delta-Tuk Peninsula and Richards Island-Beaufort Sea	P50	8473	66.2		19 507

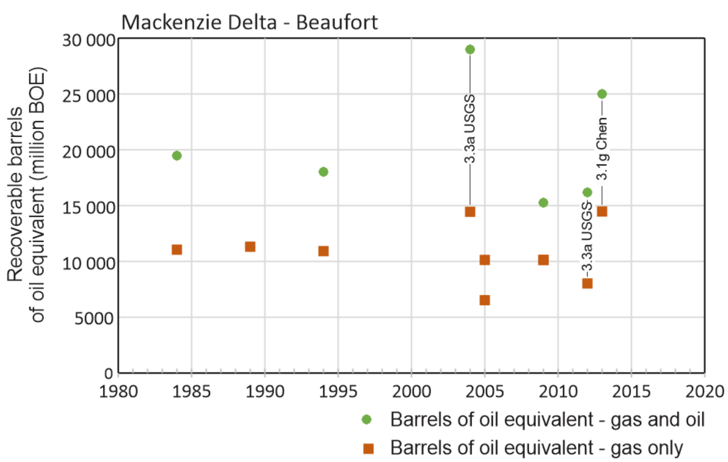


Figure 9. Total estimated resource endowment for the Beaufort-Mackenzie Delta region vs. time.

Canada Basin

Three reports provide resource assessments for the Canada Basin. The reported range of recoverable resource is from **10 533** to **14 983** millions of barrels of oil equivalent (Table 6).

The USGS (ref.3a, 2012) considered the chance of finding a 50 million barrel oil field (or 300 billion cubic feet gas field) to be less than 10% and consequently did not assess the basin. Reservoir was considered to be high risk by the USGS because the deep basinal setting implies very fine grained sediments. Dietrich (ref.3b, 2018) and Chen (ref.1g, 2013) assessments considered that deep water reservoirs would be viable, in part on borehole data from the deep parts of the Beaufort Sea, and in part from the interpretation of mass transport deposits on UNCLOS seismic lines.

The assessed values of Chen et al. (ref.1g, 2013) are higher than other assessments for methodological reasons. Chen recognized that there are positive correlations between supposedly independent model inputs and employed a statistical tool (cupolas) to adjust for this. This results in a substantially higher assessed value.

Arctic Margin

Five reports assessed the Arctic Margin between Amundsen Gulf and Ellesmere Island. The range of reported values (Table 7) are between **2563** and **7950** million barrels of oil equivalent recoverable hydrocarbon. The Banks and Eglinton Basins are geologically most similar to the Arctic Margin, but are sometimes included in the Sverdrup Basin or Stable Platform assessment areas.

The reports that assess the Arctic Margin use slightly different boundaries. Four reports have the southern boundary in Amundsen Gulf, and the northern boundary varies between central Banks Island (ref.4a; Chen, 2011) and Ellesmere Island (ref.1g, Chen, 2013; ref.3a, USGS, 2012). Lister (ref. 6d, 2021) assessed the area between Mackenzie King and Ellesmere islands. The eastern boundary varies between the offshore hinge separating thin Cenozoic strata from rapidly thickening Cenozoic strata (ref.3a; USGS, 2012; ref. 6d; Lister 2021) to the coast of the islands (ref.1g; Chen 2013). The differing choices of boundary account for some of the difference in assessed values.

These assessments were made before researchers had access to the ION seismic dataset from offshore Banks Island. The assessments are based in large part on analogues with offshore Alaska and successions in the Beaufort Sea. The GSC has recently been granted access to the ION seismic grid for the Banks margin which gives more insight into the validity of the old assessments (e.g., ref. 6d; Lister 2021). In particular, the old assessments likely overemphasised the importance of young (Cenozoic) potential source rock units and underemphasised older (Jurassic or Cretaceous) source rock units. The net effect of this on the quality of the assessments is unknown.

Table 6. Assessed values for mean recoverable hydrocarbons from the Canada Basin.

Report	Assessment Area	Ultimate Recoverable oil (million barrels)	Ultimate Recoverable gas (trillion cubic feet)	Recoverable Natural Gas Liquids (million barrels)	Recoverable barrels of oil equivalent (million BOE)
3b. Dietrich 2018	Canada Basin	4900	33.8		10 533
3a. USGS 2012	Canada Basin	Not assessed. <10% chance of 50 Mbbl discovery			
1g. Chen 2013	Canada Basin	6400	27.5	4000	14 983

Table 7. Assessed values for mean recoverable hydrocarbons from the Canadian Arctic Margin.

Report	Assessment Area	Ultimate Recoverable oil (million barrels)	Ultimate Recoverable gas (trillion cubic feet)	Recoverable Natural Gas Liquids (million barrels)	Recoverable barrels of oil equivalent (million BOE)
6d. Lister 2021	Mackenzie King to Ellesmere				2563
3a. USGS 2012	Tuk Peninsula to Ellesmere Island	2370.7	15.1	55.3	4943
1g. Chen 2013	South end of Banks to Pearya	2600	23.7	1400	7950
4a. Chen 2011	Tuk Peninsula to Banks Island	5200	15.6		7800
1f. Drummond 2009 Table 8	Arctic Coastal Plain - unrisked	1102.4	14.76		3562

Sverdrup Basin

Seven reports assessed the Sverdrup Basin. The range of assessments that quantified both oil and gas is between **5521** and **15 869** million barrels of oil equivalent recoverable hydrocarbon. (Table 8, Figure 10). Lister et al. (ref. 6d.; 2021) reported on just the igneous affected portion of the NE Svedrup Basin, with a median estimate of **773** million barrels of oil equivalent recoverable hydrocarbon.

The main exploration target in the Sverdrup Basin was Mesozoic sandstones in salt-cored anticlines. Assessments by Chen (2000, 2011, and 2013) only consider these Mesozoic structural plays. Proctor (ref.1a, 1984), USGS (ref.1d, 2008) and Drummond (ref.1f, 2009) consider both Mesozoic and upper Paleozoic plays.

Procter (ref.1a, 1984) considered Hare Fiord Formation as the source rock for 6 of the 11 upper Paleozoic plays in the Arctic Islands. Hare Fiord sourced plays account for about 32 Tcf of the assessed 40 Tcf in the upper Paleozoic, or approximately one third of the gas assessed in the Arctic Islands by Proctor (ref.1a, 1984). However, modern data show that the Hare Fiord contains little organic carbon and is a poor source rock (Galloway et al., 2018) making the Procter estimate questionable.

Sverdrup Basin Significant Discoveries

The discovered resource for Sverdrup Basin is reported between **2728** and **3298** recoverable barrels of oil equivalent, including **13.9** to **16.5** Tcf of natural gas (Table 9). The lower value were reported by Chen (ref.5b, 2000), but were based on data reported by Panarctic Oils Ltd. to the National Energy Board. The higher number was reported by Panarctic Oils in its 1983 corporate annual report.

The change in size of the discovered resource is illustrated by the reported proven and probable resource for the Drake gas field. Drake is the largest conventional gas field in Canada. Chen (ref.5b, 2000), based on data from Panarctic Oils Ltd., reported 3.7 Tcf of gas at Drake, whereas Panarctic Oils Ltd reported 5.14 Tcf in their 1983 annual report, Waylett (1990) reported 5.3 Tcf, and the Canadian Gas Potential Committee reported 5.085 Tcf (ref.1c.iii, 2005). The variation is a result of different choices in the gas-water contact marking the base of the pool. Chen (ref.5b, 2000) used the lowest drilled intersection of gas-saturated reservoir, whereas Waylett (1990) analysed the field pressure relative to the hydrostatic pressure and calculated a much deeper gas-water contact. In other words, Chen used a much more conservative shape for the field whereas Waylett used a much larger area. Waylett's calculations are well supported, logical, conform to standard industry practice and are a better estimate of the total resource in the field.

The choice by Chen (2000) to use the smaller assessment of the discovered size affects Chen's estimate of the predicted total resource. Chen uses several methods in his analysis of the Sverdrup Basin, including a version of a discovery process model that uses the decreasing size of subsequent discoveries to predict the total hydrocarbon endowment. Given that Drake is the first and largest discovery in the Sverdrup Basin, the difference of 1.4 Tcf between Chen's and Wylett's estimates would affect the trajectory of the discovery curve.

As documented in the literature, Eurekan deformation (62 to 32 Ma) damaged traps and seals, and related uplift and erosion causing gas expansion and oil loss. Based on this poor timing for petroleum systems, the USGS assessment for the Sverdrup Basin (ref.5g USGS 2020) assigned remaining undiscovered reserves of 4.9 Tcf of gas and 427 Mmbls of oil to Mesozoic strata in the Sverdrup Basin and 3.6 Tcf of gas and 424 Mmbls of oil to the Sverdrup Rim. The USGS only reports undiscovered resources, so the value reported in Table 8 includes the discovered values from Panarctic (1983).

Table 8. Assessed value for mean recoverable hydrocarbons from the Sverdrup Basin.

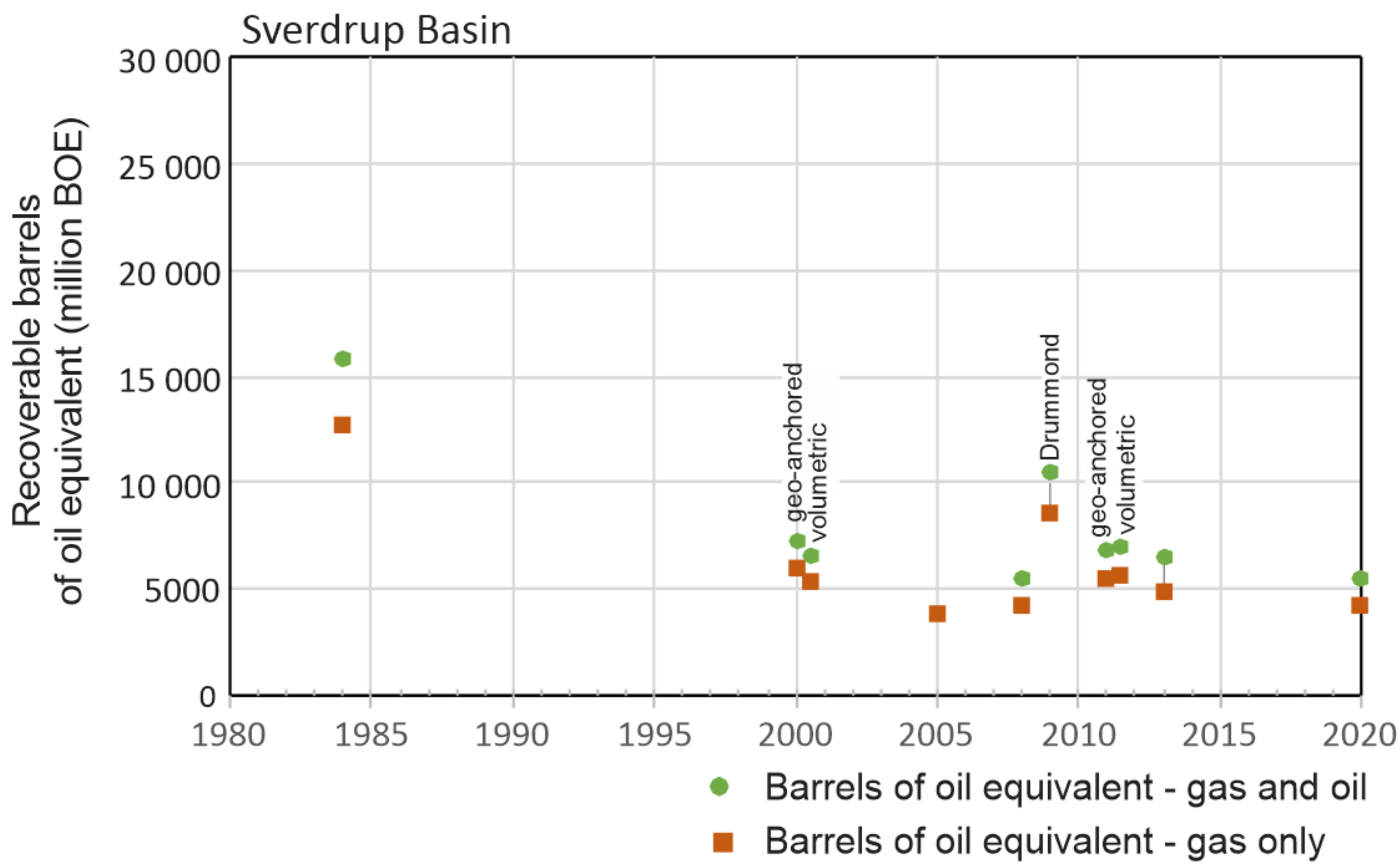
Report	Assessment Area	Reported Type	Ultimate Recoverable oil (million barrels)	Ultimate Recoverable gas (trillion cubic feet)	Recoverable Natural Gas Liquids (million barrels)	Recoverable barrels of oil equivalent (million BOE)
6d. Lister 2021	Igneous affected NE Sverdrup only	P50				773
5g USGS 2020	Sverdrup Basin and Banks Island	Mean	1343	25.07	28	5549
5e. Chen 2011 geo-anchored	Sverdrup Heiberg structural	P50	1270.1	33.5		5589
5e Chen 2011 volumetric	Sverdrup Heiberg structural	P50	1318.4	34.0		6980
1f. Drummond 2009	ALL	Mean Unrisked	1831.3	51.67		10 443
1f. Drummond 2009	Sverdrup Basin Mesozoic	Mean Unrisked	1433.8	43.10		8617
1f. Drummond 2009	Sverdrup Basin Perm-Carb	Mean Unrisked	397.5	8.57		1826
1g. Chen 2013	Sverdrup Heiberg structural	Mean	1600	29.5		6517
1c.iii CGPC 2005	All reservoir zones - Mesozoic - Sverdrup Basin	Mean	N/A	23.15		*3858 (gas only)
1d. USGS 2008	Sverdrup Basin		1343.11	25.07		5521
5b. Chen 2000 geo-anchored	Mesozoic structure Heiberg and younger reservoirs	P50	1151.1	36.69		7267
5b. Chen 2000 volumetric	Mesozoic structure Heiberg and younger reservoirs	P50	1300.1	32.32		6687
1a Proctor	ALL	P50	3161	76.25		15 869
1a Proctor	Mesozoic plays	P50	844	36.3		6894
1a Proctor	Upper Paleozoic plays	P50	2317	39.95		8975

Table 9. Discovered resources in the Sverdrup Basin.

Report	Field	Reported Type	Ultimate Recoverable oil (million barrels)	Ultimate Recoverable gas (trillion cubic feet)	Recoverable Natural Gas Liquids (million barrels)	Recoverable barrels of oil equivalent (million BOE)
5a. 1983 Panarctic Annual Report	All	Proved and probable	492	16.47	60.6	3298
5a. 1983 Panarctic Annual Report	Drake field	Proved and probable		5.144		857
5b. Chen 2000	All		406.7	13.93		2728

5b. Chen 2000	Drake field			3.711		619
Waylett, 1990	Drake field			5.305		884
1c.iii. CGPC 2005	Drake field			5.085		848

Figure 10. Mean estimated recoverable resource endowment for the Sverdrup Basin vs. time. Note that only the 1984 (ref.1a; Proctor), USGS (refs.1d, 5g; 2008, 2020), and 2009 (ref.1f; Drummond) reports assessed the entire Sverdrup Basin. Other assessments are for Mesozoic structural plays only. Chen (refs.5b, 5e; 2000, 2011) used two methods, geo-anchored and volumetric, to assess resources in the Mesozoic structural play.



Lincoln Sea & Makarov Basin (High Arctic Basins)

There are five reports on the hydrocarbon potential of the High Arctic sedimentary basins (Table 10): Lincoln Sea (ref.6a; Sørensen et al., 2011; ref 6d; Lister et al., 2021) and Lomonosov Ridge and Makarov Basin (ref.1d, USGS Circum Arctic Appraisal; ref.6b, Moore et al., 2011; ref.6c, Moore et al., 2019).

Geological data from the region is limited to several short cores and grab samples from the ocean floor, as well as a few reflection seismic and refraction seismic profiles. The assessment area boundaries are largely based on bathymetric, magnetic, and gravity data. The main stratigraphic packages are interpreted from reflection (Lomonosov Ridge) or refraction (Lincoln Sea) data.

The 2008 USGS Circum-Arctic resource assessment has a larger assessment area boundary than the two reports by Moore et al. (ref.6b; 2011, ref.6c; 2019) and includes the Siberian Passive Margin and Podvodnikov Basin.

The values reported in Moore et al. (ref.6b; 2011) are internally inconsistent between the text and abstract. The values in Moore et al. (ref.6c; 2019) are thought to accurately represent the assessment. Gas includes both associated gas (i.e., occurs with oil) and non-associated gas (i.e., does not occur over an oil pool). The Lomonosov Ridge was considered to have less than 10% chance of a 50 Mmbl field and was not assessed further. The Makarov Basin was estimated to have **304** million barrels of oil equivalent.

The Lincoln Sea has a mean assessment of **1164** to **1307** million barrels of recoverable oil equivalent (including **5.0** Tcf of gas), assuming Sørensen et al. (2011) reported in-place values. The geology and petroleum systems of the Lincoln Sea are thought to be very similar to the Sverdrup Basin, but with less erosion, and fewer igneous rocks. The Lincoln Sea basin is about one-quarter the area of the Sverdrup Basin, so the estimate of 1164 million barrels of oil equivalent is in the range of 25% of Sverdrup Basin assessments.

The lack of drilling or reflection seismic means that Sørensen's assessment makes a number of untested assumptions:

- Salt structures are predicted on the basis of analogy with the Sverdrup Basin and Barents Sea, but there is no independent evidence of salt structures from aeromagnetic or gravity surveys.

- Maximum field density used by Sørensen is 50% higher than what is demonstrated for the Sverdrup Basin. The rationale for this assumption is that the Sverdrup Basin has little exploration for hydrocarbons, but the choice of 50% higher is speculative.

- The Lincoln Sea is on the margin of the High Arctic Large Igneous Province, and local intrusion of igneous rocks could affect both charge (possible destruction of source due to local igneous heat sources) and reservoir quality (due to cementation associated with circulating fluids). The effect of igneous intrusions on the hydrocarbon potential of the Sverdrup Basin is complex (Goodarzi et al. 2019), but igneous activity may impact the chance of success for charge and reservoir.

Table 10. Assessed mean recoverable resource for the High Arctic sedimentary basins.

Report	Assessment Area	Reported Type	Ultimate Recoverable oil (million barrels)	Ultimate Recoverable gas (trillion cubic feet)	Recoverable Natural Gas Liquids (million barrels)	Recoverable barrels of oil equivalent (million BOE)
6c. Moore 2019	Lomonosov Ridge	N/A	N/A	N/A	N/A	
6c. Moore 2019	Makarov Basin	Mean	123	0.93	25	304
6b. Moore 2011	Lomonosov Ridge	N/A	N/A	N/A	N/A	
6b. Moore 2011	Makarov Basin	Mean	123	0.74	N/A	
1d. USGS 2008	Lomonosov Ridge & Makarov Basin	Mean	1106.78	7.16	191.55	2491
6a. Sørensen 2011, Table 44.3	Lincoln Sea (includes Greenland waters) - risked	Mean	270	5.04	54	1164
6d. Lister 2021	Lincoln Sea	Mean				1307
6d. Lister 2021	Lomonosov Ridge (Canada waters)	Mean				103

Baffin Margin

Five quantitative resource assessments are available for the entire Canadian Baffin Margin, and one for Lancaster Sound only. The range of assessments that quantified both oil and gas is between **1943** and **13 200** million barrels of oil equivalent recoverable hydrocarbon. (Table 11, Figure 11). This includes an assessment of approximately 9000 million barrels of oil equivalent recoverable hydrocarbon for the Canadian portion of the area assessed by the USGS (ref.7d; Schenk, 2017). This value was obtained by taking Schenk's assessment for the northeast Canadian Rifted Margin assessment area, and adding it to half the values of the Eurekan Structures, Baffin Bay Basin, and Greater Ungava fault zone assessment areas. Schenk included Greenland waters in these assessment areas, but because they span the deep water parts of the basin, they are approximately 50% on the Canadian side. There is no reason to expect higher or lower values either side of the border for these assessment areas.

The choice of southern boundary on the assessment unit is important because the northern end of the hydrocarbon-bearing Saglek Basin is approximately at 65°N, or close to the southern end of most assessment areas. There are no stand-alone assessments of the Saglek Basin. There is one discovery within the Saglek Basin, offshore from the south end of Baffin Island. Hekja O-71 is reported to contain 2.3 Tcf of natural gas (ref.7b; Krose et al. 1982; Jauer, 2009). Recent summaries of the geology and petroleum systems in the Saglek Basin are in Jauer et al. (2014; 2019). Jauer et al. (2014) estimated 100 Tcf of gas were generated in the Gudrid Member, and that the Gudrid structure to the west of the Ralegh N-18 well may potentially contain ten times as much petroleum as found in the Hekja O-71 discovery.

The range of assessed recoverable hydrocarbon resources for Lancaster Sound is from **1144** to **3467** million barrels of oil equivalent.

Knowledge about the eastern margin of Canada from Labrador to Ellesmere Island has evolved rapidly in the last few years with publication of a major paper on the Baffin Fan (a large deltaic system at the mouth of Lancaster Sound; Harrison et al., 2011), on-going seismic reinterpretation as part of the Geoscience for Energy and Mineral program (Bingham-Koslowski et al., 2018), and seismic interpretation on the Greenland shelf (Gregersen et al., 2013). A recent assessment by Brent et al. (ref.7d) does not cover the area of the Baffin fan. Schenk (ref.7d; 2017) does not reference Gregersen et al. (2013) or Harrison et al.'s (2013) work on the Baffin Fan. Schenk considered only graben systems as the geological element that would result in effective petroleum systems. Recognition of a large, post-Cretaceous delta system on the Canadian side of Baffin Bay could result in a much large resource potential than is recognized in any of the available assessments.

The complexity of the Baffin Margin has likely been under appreciated in the existing resource assessments. Assessment areas are likely too coarse and contain separate areas with quite different resource potential.

Table 11. Assessed values for mean recoverable hydrocarbons from the Baffin Margin, Davis Strait, and Lancaster Sound. Assessment areas in Schenk (ref.7d; 2017) may include Greenland waters.

Report	Assessment Area	Reported Type	Ultimate Recoverable oil (million barrels)	Ultimate Recoverable gas (trillion cubic feet)	Recoverable Natural Gas Liquids (million barrels)	Recoverable barrels of oil equivalent (million BOE)
7c. Schenk, 2017	Baffin Bay Basin (includes Greenland waters)	Mean	1555	12.27	250	3850
7c. Schenk, 2017	Northeast Canada Rifted Margin	Mean	1431	8.69	194	3074
7c. Schenk, 2017	Eurekan structures (includes Greenland waters)	Mean	1133	8.59	229	2794
7c. Schenk, 2017	Greater Ungava fault zone (includes Greenland waters)	Mean	1675	13.5	273	4200
7d. Brent et al. 2013 Table 2	Lancaster Sound	P50	2000	8.8		3467
1g. Chen 2013	Lancaster Sound	Mean	2000	8.8		3467
1g. Chen 2013	Baffin Bay and Margin	Mean	5500	25.4		9733
1f. Drummond 2009 Table 11 & 12	Baffin Bay/Davis Strait - Risked	Mean	508.1	10.0		2181
1f. Drummond 2009 Table 11 & 12	Baffin Bay/Davis Strait - Unrisked	Mean	508.1	10.0		2181
1f. Drummond 2009 Table 11 & 12	Lancaster Basin - Risked	Mean	220.8	3.62		823
1f. Drummond 2009 Table 11 & 12	Lancaster Basin - Unrisked	Mean	306.7	5.02		1144
1a. Proctor 1984	Baffin-Lancaster	P50	346	9.59		1943
7b. Klose et al. 1982	Hekja SDL	N/A		2.3		383

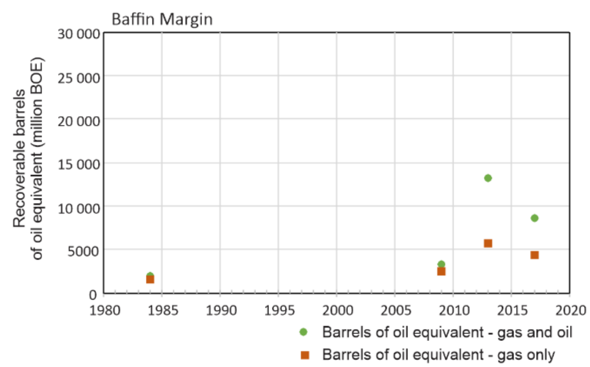


Figure 11. Total estimated mean recoverable resource for the Canadian portion of the Baffin Margin vs. time. Schenk's values for Eurekan structures, Greater Ungava fault zone and Baffin Bay Basin were divided in two to approximate the split between Canadian and Greenland waters.

Foxe Basin

Only one quantitative assessment has been made for Foxe Basin (ref.1f; Drummond, 2009). Drummond's value was obtained by multiplying the Hudson Platform assessment of Proctor et al. (ref.1a, 1984) by 7%. This value appears unreliable for a number of reasons:

Drummond (Table 12) re-ran the distributions reported in Proctor (ref.1a, 1984) using @Risk software. Drummond recalculated the recoverable resource for Hudson Platform as **1186** Mbbls. This is larger than reported by Proctor (c) who identified **817** Mbbls for Hudson Platform. It is unclear how Drummond arrived at the larger value.

The logic for applying 7% of Hudson Bay resource estimate to Foxe Basin is unclear. Drummond states that Proctor assessed both Foxe and Hudson basins, but the original files from that assessment could not be found and the final publication of Proctor makes no mention of Foxe Basin as part of the Hudson Basin assessment. If Proctor did not asses Foxe Basin, it should not be partitioned from the Hudson Platform estimate (i.e., Proctor did not report Hudson Platform + Foxe Basin, but only Hudson Platform).

Analysis of hydrocarbon potential for Foxe Basin (ref.8a; Fustic et al., 2018) and Hudson Bay (Hanna et al., 2018) would indicate low potential for the entire Foxe Basin, compared to large areas of medium potential in Hudson Bay. The difference in potential in the two areas means that the resource cannot be simply partitioned between the two.

Table 12. Assessed mean recoverable hydrocarbon resource in Foxe Basin.

Report	Ultimate Recoverable oil (million barrels)	Ultimate Recoverable gas (trillion cubic feet)	Recoverable barrels of oil equivalent (million BOE)
1f. Drummond, 2009	83	0.332	138

Franklinian Margin

Three reports include assessment for the Franklinian Margin. Proctor (ref.1a, 1984) and Drummond (ref.1f, 2009) assessed the entire lower Paleozoic Franklinian Margin, whereas Hannigan (ref.9a, 1999) assessed the lower Paleozoic hydrocarbon potential of Bathurst Island. The Franklinian Margin was not assessed by USGS because it was considered to have less than a 10% chance of a 50 million barrel field. The assessments range from **3367** to **4330** million barrels of oil equivalent recoverable hydrocarbon for the entire Franklinian margin, and **2613** million barrels of oil equivalent recoverable hydrocarbon for Bathurst Island alone (Hannigan, ref.9a, 1999).

Bent Horn, a small oil field on Cameron Island, is the only discovery in the Franklinian Margin. The complex structural setting make reserve determination difficult and the estimate of 6.2 million barrels of recoverable oil is subject to considerable uncertainty.

The poor ratio of discoveries to dry holes would appear to make the Franklinian Margin succession unprospective. Meneley (2006), however, pointed out that only 10 of the wildcat wells that penetrate lower Paleozoic strata tested their intended target. The other wells were off structure or ended above the reservoir.

Proctor (ref.1a, 1984) assessed 10 plays that are primarily stratigraphic, whereas the 9 plays evaluated by Hannigan (ref.9a, 1999) are structural. The sequence of geological events in the Franklinian Margin is not ideal for hydrocarbon accumulations for two reason. Firstly, maximum burial and hydrocarbon generation took place before the large east-west trending folds developed, and secondly, maximum burial was about 360 million years ago, leaving a long time for hydrocarbon loss or destruction. Bathurst Island may have a relatively high hydrocarbon potential, relative to its small size, because there are north-south oriented folds that developed before maximum hydrocarbon generation. This, along with the presence of rich Silurian source rocks and suitable thermal maturity makes Bathurst Island an area of relatively high potential in the Franklinian Margin

Prospectivity maps for portions of the Franklinian Margin along with play definitions and the extents of petroleum systems elements are shown in Atkinson et al. (ref.7e, 2017) and Fustic et al. (ref.8a, 2018).

Table 13. Assessed values for mean recoverable hydrocarbons from the Franklinian Margin.

Report	Assessment Area	Reported Type	Ultimate Recoverable oil (million barrels)	Ultimate Recoverable gas (trillion cubic feet)	Recoverable barrels of oil equivalent (million BOE)
1f. Drummond 2009	All plays	Mean Unrisked	992.4	14.3	3,367
9a. Hannigan 1999	All plays	Mean	1150	8.8	2,613
1a Proctor 1984	Stable Platform and Fold Belt	P50	1641.7	16.1	4,330

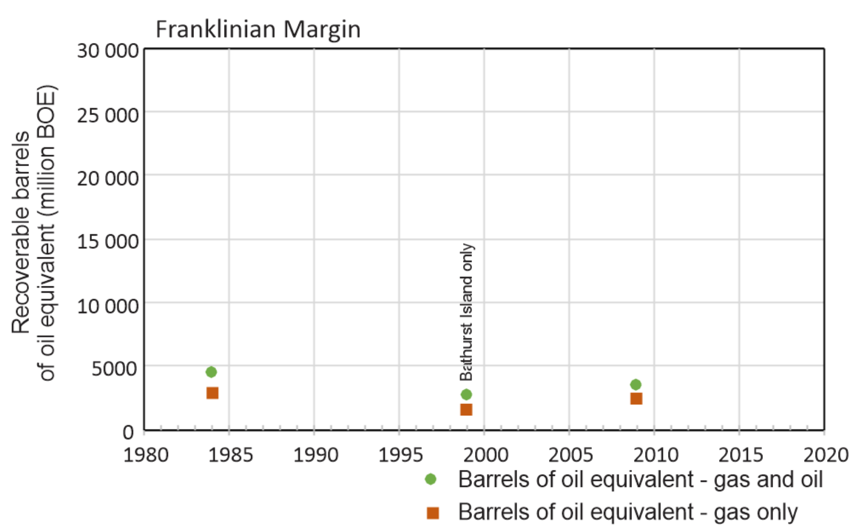


Figure 12. Total estimated mean recoverable resource for the Franklinian Margin. Note Hannigan (ref.9a) only assessed Bathurst Island, Nunavut.

Onshore and Offshore Resource Potential Allocation

Two resource assessments (ref. 1f; Drummond and ref. 2g; Sproule) separate onshore and offshore resource potential values for the Beaufort-Mackenzie Delta, Sverdrup Basin, Arctic Margin, and Franklinian Margin assessment areas (Tables 14 and 15).

Drummond and Sproule predict resource potential values using play-based inputs defined in Dixon (ref.2d, 1994). Both authors use Monte Carlo/probabilistic methods; Drummond using Petrimes, Sproule using @Risk. Total offshore and onshore resource potential are then divided based on the associated play. Plays that are entirely offshore or entirely onshore are easily assigned. To apportion the onshore/offshore potential resource of plays that are present both onshore and offshore, Drummond (ref. 1f; 2009) applied updated land/water ratios (Drummond, 1973). Drummond takes this one step further and splits petroleum resources between each northern territory. For the Northwest Territories (Table 14) these are based on plays identified in Bulletin 474 and uses an assessment area based on the northward extension of the defined onshore border between the Northwest Territories and Yukon (ref. 1f).

Sproule (ref.2g, 2005) divides the natural gas resource with **16.94** Tcf of marketable gas estimated onshore and **39.74** Tcf of recoverable gas estimated offshore. Drummond (ref.1f, 2009, Table 7) estimates ultimate recoverable onshore and offshore oil and gas resources for both the Yukon and NWT as: NWT onshore oil **695** Mmbl; NWT offshore oil **5983** Mmbl; Yukon onshore oil **0.2** Mmbl; Yukon offshore oil **1518** Mmbl. For ultimate recoverable natural gas, NWT onshore **16.3** Tcf; NWT offshore **38.0** Tcf; Yukon onshore **0.082** Tcf; Yukon offshore **6.5** Tcf.

The reliability of an onshore-offshore split is uncertain. Resource assessment methodology is calibrated at the basin scale using analogue basins from elsewhere in the World. The coast line is an ephemeral thing (geologically speaking, it moves back and forth over time) that has no meaning relative to the resource. Because hydrocarbon fields are not randomly distributed in space, the assessed hydrocarbon resource should not be simply apportioned by area.

Table 14. Reported onshore and offshore recoverable oil and marketable gas for the Northwest Territories.

Area	Report	Onshore Discovered Recoverable Oil (Mbbls)	Onshore Undiscovered Recoverable Oil (Mbbls)	Offshore Discovered Recoverable Oil (Mbbls)	Offshore Undiscovered Recoverable Oil (Mbbls)	Onshore Discovered Marketable Gas (Tcf)	Onshore Undiscovered Marketable Gas (Tcf)	Offshore Discovered Marketable Gas (Tcf)	Offshore Undiscovered Marketable Gas (Tcf)
Sverdrup Basin Mesozoic	1f. Drummond	0.00	45.17	12.10	175.17	0.00	1.00	3.50	3.89
Sverdrup Basin Perm-Carb	1f. Drummond	0.00	16.30	0.00	296.69	0.00	0.33	0.00	1.30
Franklinian Fold Belt	1f. Drummond	0.00	57.26	0.00	26.83	0.00	0.93	0.00	0.44
Arctic Coastal Plain	1f. Drummond	0.00	91.50	0.00	643.81	0.00	1163.80	0.00	8.19
Arctic Platform	1f. Drummond	0.00	36.48	0.00	37.90	0.00	0.40	0.00	0.41
Beaufort-Mackenzie Delta	1f. Drummond	141.79	553.29	1162.32	4866.29	4.80	10.36	5.59	29.96
Beaufort-Mackenzie Delta	2f. Sproule	N/A	N/A	N/A	N/A	6.54	10.40	4.30	35.40

Table 15. Total onshore and offshore recoverable oil and gas converted to MBOE for the Northwest Territories.

Area	Report	Total Onshore and Offshore Ultimate Recoverable Resource - Oil + Gas (MBOE)	Onshore Ultimate Recoverable Oil (Mbbls)	Offshore Ultimate Recoverable Oil (Mbbls)	Onshore Ultimate Marketable Gas (Tcf)	Offshore Ultimate Marketable Gas (Tcf)
Sverdrup Basin Mesozoic	1f. Drummond	1463.87	45.17	187.27	1.00	7.38
Sverdrup Basin Perm-Carb	1f. Drummond	529.20	16.30	296.69	0.33	1.30
Franklinian Fold Belt	1f. Drummond	157.68	57.26	26.83	0.93	0.44
Arctic Coastal Plain	1f. Drummond	2101.30	91.50	643.81	1.16	8.19
Arctic Platform	1f. Drummond	143.59	36.48	37.90	0.40	0.41
Beaufort-Mackenzie Delta	1f. Drummond	12 664.19	695.08	6028.61	15.17	35.55
Beaufort-Mackenzie Delta	2f. Sproule	6633.61* Gas only	N/A	N/A	16.94	39.70

Extreme Estimates

The mean predicted resource has been reported in this document so far. However, eight reports include a value for the extreme high (P5) and low (P95) ends of the predicted resource distribution. P95 means there is a 95% chance that a resource of a stated size is present, whereas P5 means a 5% chance that a resource of a stated size is present. P95 is a geologically conservative estimate, P5 is a speculative estimate of the possible upper size of the hydrocarbon resource.

Fig. 13 shows the highest P5 value for each assessment area relative to the range of reported mean values (green bars). The Beaufort-Mackenzie area has the highest predicted P5 of about 55 000 Mboe. Four plays that extend into Canada in the Baffin report of Schenk (ref. 7d; 2012) were summed using statistical tools in Rose & Associate software to produce a P5 value of 43 442 Mboe within the Canadian portion of Baffin Bay. The upper estimate for the Sverdrup Basin is 28 700 Mboe, and the upper estimate for the Makarov Basin is 2238 Mboe.

P5 cases bring awareness to what the potential upside of an assessment area could be, but the P5 cases per assessment area are not directly comparable as the distributions are basin defined differently. P5 is especially sensitive to what the model is given as a maximum possible field size. For instance, the USGS derives probabilities based on their analogue database but in the case of Baffin Margin where the analogue database indicates a maximum oil field size of 1000 Mboe, Schenk (ref. 7d; 2012) uses a maximum possible recoverable resource six times larger than the analogue value. Other USGS reports use maximum values of five times the maximum field size indicated by the analogue database. The influence of these choices on the P5 values, or even the P50 values, is unclear.

Where the P5 cases are very large (in comparison to annual national production rates), the modeling choices could benefit from further studies to more precisely define the maximum possible field size, P5 and P50 cases.

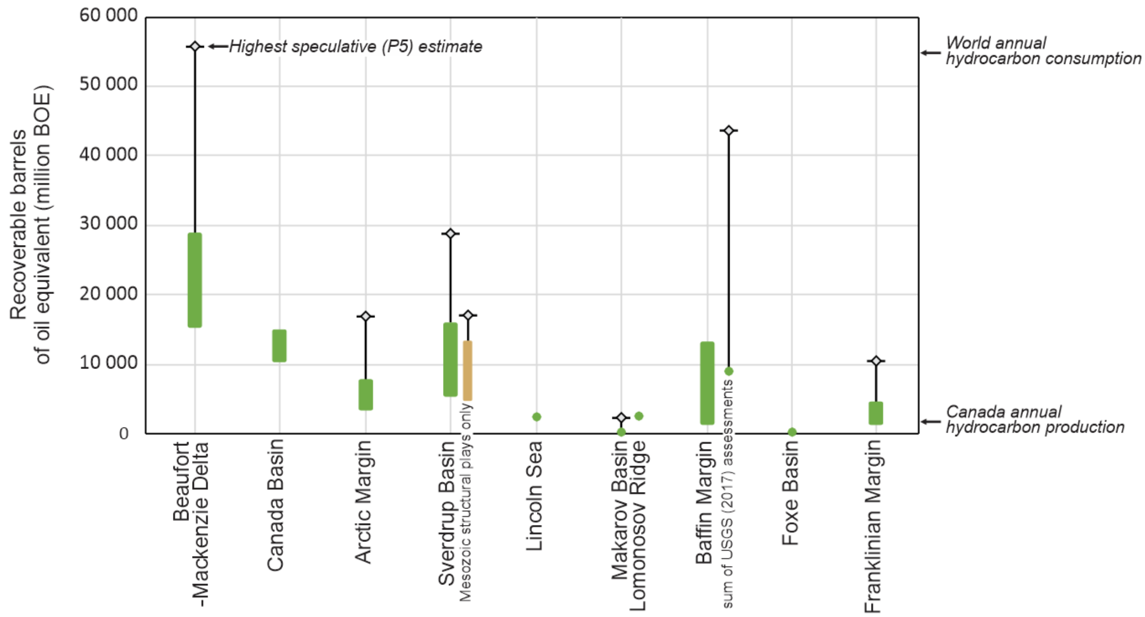


Figure 13. Range of mean recoverable estimates in millions of barrels of oil equivalent (green bar) and the highest speculative (P5) estimate are available for 6 basins (grey diamond). The four individual plays considered for the Baffin Margin by the USGS (ref.7d; 2017) are summed statistically with 50% of the assessment areas straddling the international boundary assigned to Canada. World oil consumption and Canadian production are from BP's annual energy report.

APPENDIX A1. Petroleum Systems Elements

Petroleum systems elements are the geological components and processes necessary to generate and store hydrocarbons, including a mature source rock, migration pathway, reservoir rock, trap, and seal. These elements need to occur in the right order for hydrocarbons to accumulate and be preserved.

Source

A sedimentary rock rich in organic matter which, if heated sufficiently, will generate oil and/or gas. Migration is the movement of hydrocarbons from the source to the trap

Reservoir

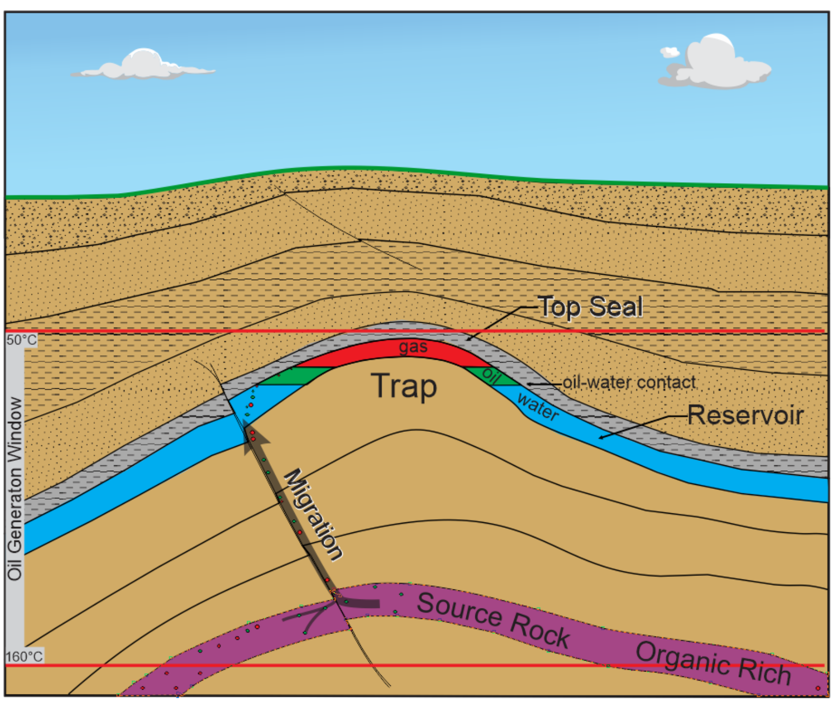
A porous and permeable rock that holds hydrocarbons

Trap

A natural closure ("dam") in which petroleum accumulates. Traps are described as structural traps (such as folds and faults) or stratigraphic traps (unconformities, pinch-outs and reefs)

Seal

An impermeable layer that prevents hydrocarbons from moving upwards



Glossary

Hydrocarbon: class of organic molecules composed of carbon and hydrogen, typically linked in chains. *Natural gas* is a gas of natural origin composed of hydrocarbon molecules, primarily methane, but may contain non-hydrocarbon gasses such as H_2S or CO_2. *Natural gas liquids* are low-density liquid hydrocarbons that may be present with natural gas. Its existence as a liquid phase depends on temperature and pressure conditions in the reservoir. *Oils* are naturally occurring liquids composed of a complex mixture of hydrocarbon molecules.

Resource: all hydrocarbon accumulations known or inferred to exist in an area. Discovered resources are those that have been drilled and their volume estimated. Undiscovered resources are inferred to exist.

Pool: a discovered accumulation of hydrocarbon typically within a single stratigraphic unit that is separated from other hydrocarbon accumulations.

Field: one or more hydrocarbon pools within a single trap.

Prospect: an untested trap that may or may not contain hydrocarbons.

Play: a group of hydrocarbon fields or prospects in the same region that are controlled by the same petroleum systems elements. Established plays have been demonstrated to exist due to the discovery of a pool. Conceptual plays are those that have no discoveries or reserves, but which geological analysis indicate may exist.

Closure: the vertical distance from the highest point of a hydrocarbon field to the lowest level in that field that could trap hydrocarbons. The area of closure is the map view extent of a closure.

Porosity: holes in rock that can contain oil or gas. *Permeability* is the connection between porosity.

Reservoir thickness: Thickness of the stratigraphic interval in which reservoir beds are present, including non-productive intervals interbedded between the productive intervals.

Net Pay: sum of the thickness of intervals in which porosity and permeability are sufficient to produce oil or gas.

Saturation: the fraction of the pore space occupied by hydrocarbon. The remaining pore space not filled by hydrocarbon

Trap Fill: percentage of the available volume of reservoir in a trap that contains oil or gas. Traps may be underfilled due to limited supply of hydrocarbon from source rocks or because the top seal lacks the strength to hold a larger column of hydrocarbon.

Gas in place: total gas volume existing in the ground. *Recoverable gas* is the volume expected to be recovered with current technology.

Recovery Factor: the percentage of the total oil or gas recovered from a reservoir during production.

[Based on definitions in Hannigan et al. 1999, ref.9a]

Geological Reading List

Ref 1b. Northern Oil and Gas Directorate. 1995. Petroleum Exploration in northern Canada: A guide to oil and gas exploration and potential. 110 p.

Beaufort-Mackenzie Delta

Dixon, J, 1996. Geological atlas of the Beaufort-Mackenzie area; Geological Survey of Canada, Miscellaneous Report 59, 173 p.

Canada Basin

Dietrich, J.R., Chen, Z., Hannigan, P.K., Hu, K., and Yu, X., 2018. Oil and gas resource potential in the deep-water Canada Basin, Arctic Ocean; Geological Survey of Canada, Open File 8355, 28 p.

Arctic Margin

Kumar, N., Helwig, J., and Dinkelman, M.G>, 2009. Preliminary Evaluation of a Potential Major Petroleum Province from BeaufortSPAN™ Seismic Data: Canadian Arctic Passive Margin, Banks Island Segment; CSEG Recorder, v. 35, no. 5.

Eglinton and Banks Basins

Miall, A.D., 1979. Mesozoic and tertiary geology of Banks Island, Arctic Canada, the history of an unstable craton margin; Geological Survey of Canada, Memoir 387, 235 p.

Harrison, J.C. and Brent, T.A., 1991. Late Devonian-Early Carboniferous Deformation, Prince Patrick and Banks Islands [Chapter 12: Silurian-Early Carboniferous Deformational Phases and Associated Metamorphism and Plutonism, Arctic Islands]; *in* Geology of the Innuitian Orogen and Arctic Platform of Canada and Greenland, (ed.) H.P. Trettin; Geological Survey of Canada, Geology of Canada Series no. 3, p.334-336.

Sverdrup Basin

Embry, A.F., and Beauchamp, B. 2019. Sverdrup Basin. In: Miall, A. (ed.) The Sedimentary Basins of the United States and Canada (Second Edition), pp. 559-592.

High Arctic Basins

Sørensen, K., Gautier, D., Pitman, J. Jackson, H. R., and Dahl-Jensen, T., 2011. Chapter 44 Geology and petroleum potential of the Lincoln Sea Basin, offshore North Greenland; Geological Society, London, Memoirs, Volume 35, p. 673–684.

Moore, T.E., Grantz, A., Pitman, J.K., and Brown, P.J., 2011. Chapter 49, A first look at the petroleum geology of the Lomonosov Ridge microcontinent, Arctic Ocean; Geological Society, London, Memoirs, Volume 35, p. 751–769

Baffin Margin

Bingham-Koslowski, N., McCartney, T., and Bojesen-Koefoed, J., in press. Hydrocarbon resource potential in the Labrador-Baffin Seaway and onshore west Greenland; *in* the Geological Synthesis of Baffin Island (Nunavut) and the Labrador-Baffin Seaway, (ed.) L.T. Dafoe and N. Bingham-Koslowski, Geological Survey of Canada, Bulletin 608

Foxe Basin

Trettin, H.P., 1975. Investigations of Lower Paleozoic Geology, Foxe Basin, northeastern Melville Peninsula, and parts of northwestern and Central Baffin Island; Geological Survey of Canada, Bulletin 251, 177 p.

Franklinian Margin

Dewing, K., and Obermajer, M, 2009. Lower Paleozoic thermal maturity and Hydrocarbon Potential of the Canadian Arctic Archipelago; Bulletin of Canadian Petroleum Geology, v. 57, no. 2, p. 141-166.

APPENDIX A2. Types of Hydrocarbon Assessments

Hydrocarbon assessments estimate the total hydrocarbon endowment of an area. Highly explored and producing areas, such as Western Canada Sedimentary Basin, have a wealth of geological, geophysical, and production data that are used to produce well-constrained resource estimates. In contrast, frontier areas have few discoveries and there is relatively little geoscience information available.

There are four main resource assessment methodologies. The methodology chosen and precision of an assessment depends strongly on the level of geological knowledge. If the level of geological knowledge is low, then input parameters chosen for statistical modelling will be poorly constrained resulting in a resource estimate with a wide range, or an inaccurate assessment if input parameters are chosen incorrectly.

Type 1 - Volumetric Yield

The volume of sedimentary rock in a basin is multiplied by a hydrocarbon yield per unit volume to produce a quantitative assessment. Widely used in the 1950s – 1970s prior to the advent of powerful computers. Updated with a mass balance approach in the 1980s using more sophisticated knowledge of source rock yields and thermal maturity. The gross quantity of oil or gas generated, along with estimated expulsion and entrapment coefficients, were used to give a bulk resource estimate.

Strengths: Easy to understand, works in areas of little or no data.

Weaknesses: cannot be used for economic analysis, no geographic information, and weak links to geology.

Example publication: Lerand, 1973 (ref B.1)

Type 2a - Probabilistic / Monte Carlo Using Analogue Estimates

Quantitative. A probabilistic / Monte Carlo approach to derive a statistically-driven resource estimate. Input parameters are chosen from geologically-similar analogue basins elsewhere in the world. A value for each input parameter is randomly chosen from the statistical distribution of the input population during each Monte Carlo run. Many Monte Carlo runs are then aggregated to give a probabilistic distribution of basin-scale resource volumes. Widely used from 1980s – present, including by the USGS. There are many variants, such as those that use truncated distributions, which were employed in the 1980s and 1990s to reduce computational load.

***Strengths*:** Statistically robust, provides range of uncertainty in the assessment (P90-P50-P10)

***Weaknesses*:** Choice of input parameters and analogues somewhat subjective. Older methods may be biased because exploration finds the best fields first; not all input parameters are independent of each other. Newer Monte Carlo simulations can statistically accommodate these dependencies; no geographic information on the location of the resources. Not explicitly linked to geology.

Example publication: USGS Report 2012-5146 (ref 3.3a) et al., 20181973

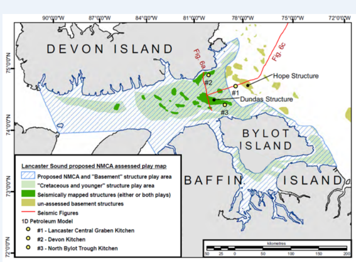
Type 2b - Probabilistic / Monte Carlo Using Volumetric estimates

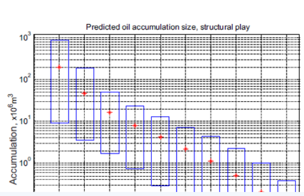
Quantitative. Uses knowledge from exploration plays in a basin, such as drilling and seismic data, to establish a probabilistic distribution of input parameters. A value for each input parameter is randomly chosen from the statistical distribution of the input population during each Monte Carlo run. Many Monte Carlo runs are then aggregated to give probabilities resource volumes and pool size distributions

***Strengths*:** comprehensive; explicitly linked to geology; volumetric variables easy to measure if data density high; provides information for economic analysis.

***Weaknesses*:** Sampling bias in reservoir parameters; correlation between geological variables; subjectivity in estimation of number of pools and risk. Needs high data density.

Example publication: GSC Open File 6954, Brent et al., 2013.





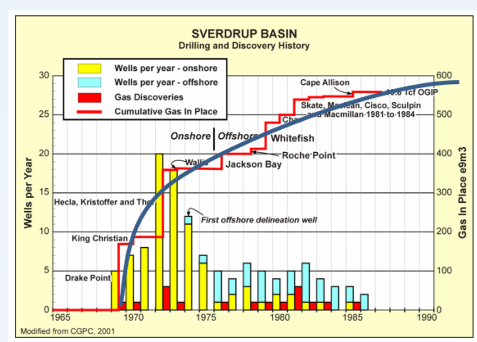
Type 3 - Discovery Process

Quantitative. Assumes a logical exploration process in which the largest field will be found first, and subsequent discoveries will be smaller. A mathematical (rarefaction) curve is generated that plots the cumulative discovered resource size. The curve is projected into the future to estimate the total resource.

Strengths: simple, objective, information for economic analysis

Weaknesses: no link to geology; sensitive to play definition; misses conceptual plays; need sufficient number of discoveries to be statistically significant; discovery process may be biased by logistical constraints in exploration (i.e., exploration may not be a logical process). No range of resource.

Example publication: Chen and Osadetz, 2011



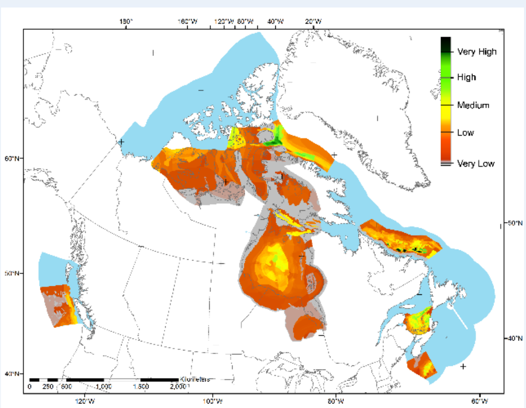
Type 4 - Prospectivity Map

Qualitative. Petroleum systems elements for each play are mapped and assigned a chance of success. The chance of success for each petroleum system element for each play are multiplied to produce a map showing hydrocarbon potential as it varies geographically.

Strengths**:** transparent, results spatially represented, simple to understand, explicit link to geology, can be used to apportion previous numerical estimates; useful for land use planning. The GSC method documents all inputs so is transparent.

Weaknesses: no volumetric estimate, cannot be used for economic analysis

Example publication: GSC Open File 8297, Atkinson et al., 2017



APPENDIX A3. Sources of Error and Pitfalls in Previous Resource Assessments

Transparency

Published resource assessments commonly lack transparency on input parameters and details of methods. This makes it difficult to gauge the quality of the assessment. Older resource assessments did not publish their inputs because they were frequently based on confidential company data; there were concerns over outsiders questioning the methods and results; uncertainties inherent to estimates at the individual play level might be reduced by presenting an aggregate number for a large number of plays; and there were concerns over raising public expectations. The statistically-based Monte Carlo simulations report input parameters as a distribution rather than a single number, making it more difficult to communicate to non-specialists

Oil vs Gas ratio

One input into the algorithms that produce the final assessment is the expected ratio between oil and gas phases. This ratio can vary depending on the state of knowledge and the assessment team's judgement. The amounts of oil and gas can be compared by the conversion of gas to 'barrels of oil equivalent' (BOE) using the formula 1 barrel oil = 6000 cubic feet of gas.

Reporting

Resource assessments can report phases and volumes differently, and reported volumes can be truncated by economic or technological filters. Almost all assessments report natural gas and oil phases; some report natural gas liquids separately, some convert oil and gas to barrels of oil equivalent (BOE). Units can be reported in cubic metres (m^3) or barrels of oil and cubic feet of gas. Resource volumes can be reported as in situ (meaning all hydrocarbons in oil or gas pools), recoverable (meaning the volume of hydrocarbon that could be produced using existing technology), or marketable (meaning that expansion and surface losses have been considered). Assessments by the GSC report the ultimate discovered and undiscovered resource, whereas other organizations (e.g., USGS) report only undiscovered resources. Conversions, especially from in situ to recoverable, can introduce uncertainty because the recovery factor used in assessments is rarely reported.

Software

Improvements in computing power and software mean that more recent assessments rely on larger number of Monte Carlo trials per simulation, and are based on more complete analogue databases. Lack of computing power in the early assessments hindered understanding the tails of distributions.

Incorrect play definition

Incorrect play definitions can lead to an over estimate of hydrocarbons resources, or missed conceptual plays may lead to underestimation of hydrocarbons resources. For example, in Procter et al. (1984), Hare Fiord Formation was considered as the source rock for 6 of the 11 upper Paleozoic plays in the Arctic Islands. Hare Fiord sourced plays account for about 32 Tcf of the assessed 40 Tcf in the upper Paleozoic, or approximately one third of the gas assessed in the Arctic Islands by Proctor et al. However, modern data show that the Hare Fiord contains little organic carbon and is a poor source rock (Galloway et al., 2018) making the Procter estimate questionable.

Herding

Given the complexity and time-consuming nature of resource assessments, authors may make methodological choices, or use input parameters, that end up making their resource assessments converge on previous ones. For instance, almost all assessors use the same USGS world analogue database, and there are only a few software packages for assessments. Any biases or deficiencies in those tools will be repeated in multiple assessments.

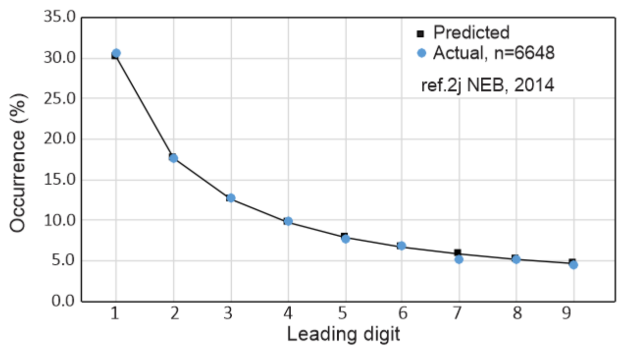
Inappropriate inputs, analogues

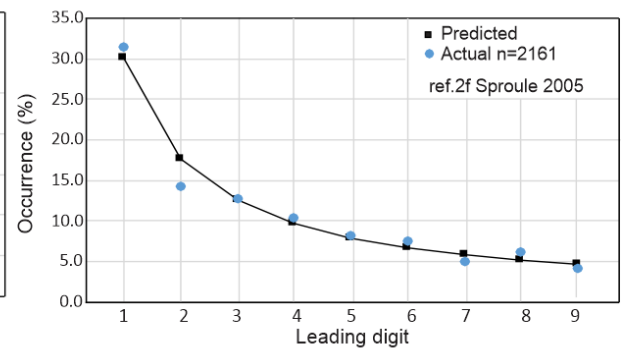
Field size distributions and the number of expected fields can be estimated from analogue populations. Other factors, such as risking charge, reservoir and timing are, to some degree, subjective. Different professional judgements for these choices means different assessment groups may use quite different risking.

APPENDIX A4. Internal data checks

Checks were performed to gauge consistency within a report (A) and between reports (B). Reports are internally consistent, but there are apparent inconsistencies in the ways that the extreme values are calculated.

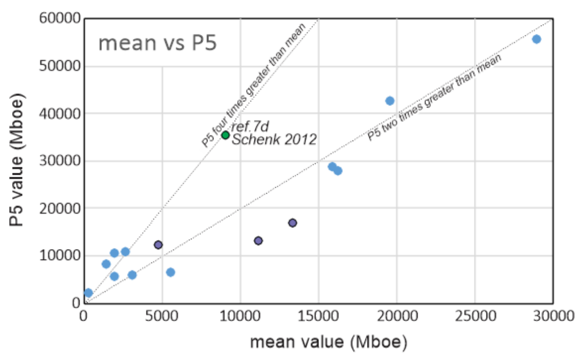
A) Benford's Laws predicts that in a complex, derived dataset, the leading digit "1" should occur more frequently than "2", which is more frequent than "3" etc. The digital files from two assessments (ref.2j; NEB 2014 and ref.2f; Sproule 2005) were parsed to isolate the leading digit. In both cases, the actual distribution is very close to the predicted.

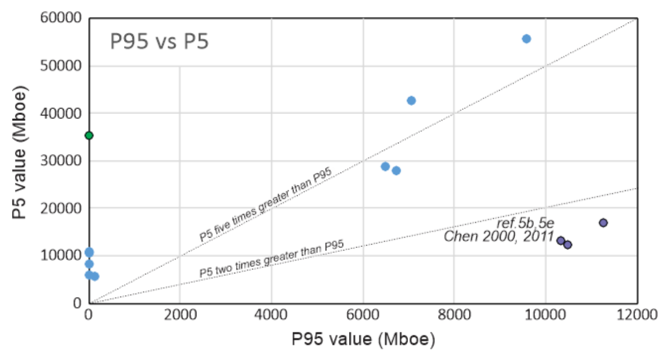




B) Cross correlation of Mean vs. P5 shows that the P5 values predicted by Schenk (ref. 7d; 2012) for the Baffin Margin are much higher than other reports. This seems to be due to the choice of a much higher maximum possible field size in the probability distribution (5000 Mboe) than other reports from rifted margins (1000-2000 Mboe). Note that the aggregate value for Schenk was summed arithmetically, but will be within a few percentage of the value derived from a new Monte Carlo simulation of all plays.

Cross correlation of P95 vs P5 shows the assessments of Chen (refs.5b, 5e; 2000, 2011) have a much lower overall range between P95 and P5 than other reports. See discussion in Haryott and Otis (2009).





APPENDIX B. Summary of Historical Resource Assessments

Definitions, constraints, & mathematical / statistical factors

i) Distinction of oil, gas, natural liquid gas, and total reservoirs (conventional only)

- Only conventional resources are considered. This report does not include gas hydrates, unconventional/coal bed/tight oil or tight gas.
- Reporting is standardized to a common mean recoverable resource in millions of barrels (Mbbls) or trillions of cubic feet (Tcf). In many ways, an *in situ* Oil-in-Place (OIP) or Gas-in-Place (GIP) is more useful because economic analysts could then apply their own recovery factors. However, recoverable resource is most commonly used in the existing resource assessments and converting to an *in situ* value introduces uncertainty because the recovery factors are generally not reported.
- Double fill problem. Some assessments report Oil <u>or</u> Gas. The oil volume is if all the traps were filled with oil, and the gas volume is if all the traps were filled with gas. These are two end members based on one phase or the other being present.

ii) Demonstrated or assessed cases

- P90-P50-P10. P90 means that there is a 90% chance that a resource of this size is present. P50 is the average expectation where there is a 50% chance that the resource is bigger and 50% that it is smaller, and P10 means that there is a 10% chance of a resource of this size being present. P50, median and mean may not be equal because the distribution may be skewed.
- Because the size distributions are skewed and produced using a Monte Carlo methodology, it is statistically incorrect to add or average values from different areas to produce a total. Totals are established using non-arithmetic statistical calculations.

iii) Conversion factors and definitions

- To convert to barrels of oil (bbls) from cubic metres (m^3), multiply by 6.29
- To convert to cubic feet from cubic metres, multiply by 35.3
- To convert cubic feet of gas to barrel of oil equivalent (BOE), assume 6000:1 ratio
- To estimate *in situ* from recoverable: oil x4; gas x 1.33. This assumes a 25% recovery for oil and 75% recovery for natural gas. Very few assessments explicitly state the recovery factor used, and one can not back calculate the recovery factor used, because of the probabilistic nature of assessments (i.e., a probabilistic distribution of recoveries is used in the Monte Carlo simulation).

Appendix B. Summary of Assessments

There are three distinct eras in which resource assessments and methodologies have been performed in the Canadian Arctic: pre-1980 assessments that relied on rudimentary software and computing power and limited geological data; the 1984 national assessment that relied on statistically robust software and had access to much of the data produced in the 1968-1986 exploration boom in the North; and post-1984 assessments that use increasingly sophisticated software and geological knowledge.

B.1 Pre-1980 Industry Assessments

A number of hydrocarbon resource assessments were performed in the early phases of exploration of the Canadian Arctic regions. In 1969, the Canadian Petroleum Association (CPA) used a volumetric yield method to estimate 43.45 Bbbls and 261.7 Tcf for the Arctic Islands. The National Energy Board held hearings in 1974 and reported on Canadian natural gas, supply, and requirements in 1975 (NEB, 1975 Table 18, p. 44). At this time, CPA submitted high, average, and low estimates of 240, 186, 86 Tcf gas for the Arctic Islands; Foothills Pipelines estimated 113 Tcf and Gulf Oil Canada estimated 100 to 200 Tcf (see Stuart Smith and Wennekers, 1977).

Scientific articles at this time were either focused on the reserves associated with individual discoveries (e.g., Stuart Smith and Wennekers, 1977; Rayer, 1981), used Discovery Process (Waylett, 1979), or Volumetric Yield methods (Drummond, 1973; Lerand, 1973; Rudkin, 1973). The best documented is "The Future Petroleum Provinces of Canada - their Geology and Potential" (Canadian Society of Petroleum Geologists, Memoir 1, 1973) which included papers on the Beaufort region by Lerand (p. 315-386) and the Arctic Islands by Drummond (p. 443-472).

Comparisons of the 1973 volumetric methods to modern reported recoverable millions of barrels of oil equivalent are grossly under- (ref. Lerand, 1973) or over- (ref. Drummond, 1973; Rudkin, 1973) estimated at 70-85% less and 200-400% more for similar assessment areas. This is due to a simplified volumetric yield with three parameters: basinal area extent, gross volume of formation, and the Canadian Petroleum Association's standard volumetric yield. Estimated values for these parameters were appropriate at the time based on geological understanding and limited data, but these volumetric yield values are coarse and do not accurately represent the complexity of an assessment area.

Assessment Area(s): Defined by figures in text showing sediment thickness (isopachs) at basin scale.

Input parameters: Volumes of strata for different basins are given by ages and sediment type. Note, Drummond included continental shelf and slope in area calculations, but not in the volume estimates. Ranges of potential hydrocarbon yield are given for each basin, but not by age or rock type.

Assessed Resource: Lerand and Drummond do not give resource estimates despite providing most of the data to do so. Rudkin provided a resource estimate, but no shapes for the assessment areas and no input parameters. Reported values are for recoverable oil and gas. We take Lerand's value of 46,000 bbls/mile^3 as equivalent to P50.

Assessment Quality: Volumetric yield method is not linked to geology. No rationale or analogues are given for yield factors. The assessments were made prior to most drilling, seismic, and geological research. This means that there was a poor knowledge of stratigraphy, thermal maturity, and reservoirs compared to today.

Normalized Resource in Place – Reported recoverable for oil was based on a recoverable yield of 46,000 bbls/cubic mile (Canadian Petroleum Association (CPA), 1969). There is no reference to define recovery factor associated with 46,000 bbls/cubic mile. To calculate in-situ would require a range of appropriate values for that time; oil (10-30%) and gas (50-80%).

B.2 Pre-1984 Geological Survey of Canada Assessments

The GSC started to produce hydrocarbon resource estimates for the entire country in 1973. The results of these assessments were circulated within government every few years as the models were updated using new information from drilling and field studies. The GSC has retained files that contain fairly complete summaries of the 1973, 1974, 1976, and 1979 assessments, as well as panel reports on the Beaufort Mackenzie Delta and the Arctic Islands. GSC Paper 83-21 by Proctor et al. supersedes these assessments.

Assessment Area(s): By basin. The 1976 assessment has a map showing assessment areas (their Fig. 3) but other reports have no record of assessment area boundaries. Given that it was a single team producing these reports, it is likely that the area enclosed by each assessment area remained the same from 1973-1979.

Methodology: Monte Carlo / Probabilistic for pool size and play potential using Hydrocarbon Assessment System Processor (HASP) software. Future discovery rates were modelled using a Markov Chain and sampling without replacement from the population of hypothetical pools. This data can be combined with data on discovered pools for a discovery process (rarefaction) model.

Input parameters and play definitions: The assessment method used area of closure, reservoir thickness, porosity, net pay, trap fill, recovery factor, depth and saturation as input parameters. Only summary documents remain in the files so the actual input parameters for each play cannot be determined.

By 1979, the Mackenzie Delta-Beaufort region considered four regions (Richards Island/Beaufort Sea; West Beaufort; South Delta; Tuk Peninsula) with a total of 18 plays. Four areas in the Arctic Islands were considered (Arctic Stable Platform; Arctic Fold Belt; Sverdrup Basin; Arctic Coastal Plain) with up to 28 plays. The Baffin Shelf assessment considered 8 plays, but there is no documentation on play definitions.

Constraints and/or Filters: Resource assessments considered plays to 25,000 feet? (7.6 km) and reported as ultimate recoverable oil and gas. The 1973 summary reported P50 values. The 1974 report introduced an economic cutoff whereby oil and gas in pools considered to be too small to be economic were excluded. The cutoffs are between 2 and 5 Tcf and 150 to 500 Mbbls depending on the area. The details for each area are in the original report. No economic cutoffs seem to have been applied to the 1976 or 1979 reports.

Quality: These assessments used a Monte Carlo method, which improved on the older volumetric yield assessments by producing a range and probability curve for the total resource. The analogue database, software, and computing power were limited compared to later assessments and the regional geological knowledge improved rapidly during this time as the 1970s-1980s exploration boom provided more drilling and seismic data.

B.3 Relevant Publications

1. All regions

1a. Procter, Taylor and Wade, 1984. GSC Paper 83-21

This was the first published comprehensive national hydrocarbon resource assessment for Canada using a common method. It built on the reports produced between 1973 and 1979 as well as two internal Panel Reports on separate basins.

Year	Synonymous Publications and Reports	Author (s)
1984	Oil and Natural Gas Resources of Canada, GSC Paper 83-31	Procter, R.M., Taylor, G.C., and Wade, J.A.
1983	Petroleum Resources of the Mackenzie Delta – Beaufort Sea, Panel Report 83-03	Dietrich et al.
1983	Petroleum Resources of the Arctic Islands, Panel Report 83-01	Embry et al.

Assessment Area(s): Basins were divided into plays, each of which was assessed separately and the results compiled into a basin total. Play areas and definitions are not included in the final publication. Panel Reports exist for the Arctic Islands and Beaufort Mackenzie regions. These list the assessed resources for 20 plays in the Mackenzie-Beaufort region, and 28 plays in the Arctic Islands. The totals of these plays are the values reported in Procter et al. (1984). Note that the Banks and Eglinton Basins are included as part of the lower Paleozoic Stable Platform.

Methodology: Monte Carlo / Probabilistic using Hydrocarbon Assessment System Processor (HASP) software.

Input parameters and play definitions: The Mackenzie Delta-Beaufort region considered four regions (Richards Island/Beaufort Sea; West Beaufort; South Delta; Tuk Peninsula) with a total of 20 plays. Four areas in the Arctic Islands were considered (Arctic Stable Platform; Arctic Fold Belt; Sverdrup Basin Paleozoic; Sverdrup Basin Mesozoic) with a total of 28 plays. Eighteen of the 28 plays in the Arctic Islands have a file on the inputs and play definitions stored at the Geological Survey of Canada. Files for the other areas are presumed to have been destroyed.

The assessment method considered area of closure, reservoir thickness, porosity, net pay, trap fill, recovery factor, depth, and saturation as input parameters based on data available to 1982. The panel report on the Arctic Islands (Embry et al. 1983) contains some play definitions and pool size distribution curves. The Mackenzie-Beaufort region panel report (Dietrich et al., 1983) contains fewer examples of input parameter.

Constraints and/or Filters: No economic filter was applied. A recovery factor was applied as part of each Monte Carlo run. Because of this, no ‘average’ value exists that can be used for back calculation.

Quality: The quality of the assessment was very high for its day. The inputs were based, in part, on exploration data and the software was statistically robust, however, the lower number of Monte Carlo runs may not have accurately modelled the tails of the distribution. The assessment lacks transparency in that the original files are largely missing so the assessed areas, play definitions and input parameters are often unknown.

Improvements in knowledge of source rocks and thermal maturity have rendered some of the plays considered in Proctor et al. (1984) invalid. For instance, Hare Fiord Formation was considered as the source rock for 6 of the 11 upper Paleozoic plays in the Arctic Islands. The models were run with a source chance-of-success of 100%, and a combined maturation, migration and preservation chance-of-success of 80%. These Hare Fiord sourced plays account for about 32 Tcf of the assessed 40 Tcf in the upper Paleozoic. However, modern data show that the Hare Fiord contains little organic carbon and is a poor source rock (CGPC, 2001; Galloway et al., 2018). This illustrates how a poor choice of input parameters can lead to inaccurate assessments. Roughly a third of the gas assessed in the Arctic Islands by Proctor et al. (1984) is now considered unrealistic.

Later evaluation by the Canadian Gas Potential Committee (2001) identified the GSC/NEB approach as having:

- A high number of plays defined in each basin.
- A high probability is assigned that each play is present.
- Plays are given a very small chance of failure.
- A large number of prospects is predicted.
- The assessment for an area is the sum of the potential for each play involved. The resulting mean assessment is too high and the probability of finding more than the mean is too high.
- No peer review with industry was conducted.

Collectively these characteristics will result in larger resource assessments for Procter et al. (1983); Dixon et al. (1994) and the NEB assessment (1998) compared to the Canadian Gas Potential Committee (1997, 2001, 2005).

1b. Petroleum Exploration in northern Canada: A guide to oil and gas exploration and potential. 1995, Northern Oil and Gas Directorate

Assessment Area(s): All sedimentary basins in northern Canada including the mainland NWT and Yukon, Mackenzie Delta and Beaufort Sea, Canadian Arctic Islands, and eastern Arctic including Baffin Bay and Foxe Basin. The document does not include information on the Canada Basin.

Methodology: Descriptive summary of petroleum system elements, exploration history, and discovered resources. No new resource assessments were undertaken.

Quality: The document provides a concise summary of the petroleum system elements and regional geology of each area. While it has been superseded by improvements in regional geological and geochemical understanding, it remains a useful reference for understanding the regional and historical context.

1c. Canadian Gas Potential Committee (CGPC). Natural Gas Potential in Canada; 1997, 2001, and 2005.

Year	Synonymous Publications	Author (s)
2005	Natural Gas Potential in Canada	CGPC
2001	Natural Gas Potential in Canada	CGPC
1997	Natural Gas Potential in Canada	CGPC

i. Natural Gas Potential in Canada 1997

Assessment Area(s): Regional study of natural gas potential of Canada.

Methodology: Quantitative using PETRIMES software, including the Discovery Process and Match Modules for mature exploration plays, and a probabilistic method for poorly explored plays. Assessment sequence including detailed steps is provided.

Input parameters and play definitions: Assessments were performed if discoveries were made in an area.

Beaufort Basin – Bulletin 474 and Procter et al. (1984) were used to provide regional geology settings and play definitions. CGPC simplified by dividing into only 2 major play groups, Cretaceous wedge base and Paleozoic subcrop, and Tertiary wedge top reservoirs.

Arctic Islands – Focussed efforts were made strictly for Sverdrup Basin as this was the only area where gas discoveries had been made at the time. Only preliminary and qualitative assessments were made for the rest of the Arctic Islands.

Constraints and/or Filters: Only assesses natural gas. Also considers Nominal Marketable Gas based on economic filters.

Assessed Resource: The assessment reports number of pools, initial gas in place, initial recoverable gas, and initial marketable gas for both discovered pools and undiscovered plays.

Quality: Compared to NEB and GSC methods, CGPC views risk in frontier areas as higher than the NEB so assesses lower volumes. See discussion under Procter et al. (1983). The higher risk was due to lack of information; they believed that frontier areas weren't as well understood as the GSC thought at the time.

ii. Natural Gas Potential in Canada 2001

Assessment Area(s): Regional study of natural gas potential of Canada. The document includes page-sized maps showing the assessment areas. Note that the Eglinton Basin is included as part of the Sverdrup assessment area.

Methodology: Quantitative using PETRIMES software, including the Discovery Process and Match Modules for mature exploration plays, and a probabilistic method for poorly explored plays. There is extensive documentation of the method used.

Input parameters and play definitions: Input data includes information available to year end 1998. The Mackenzie-Beaufort assessment considers 4 plays (Basin Margin Parson Group zone; Listric Fault zone;

Shale Cored anticline structural and stratigraphic trap zone; tilted fault block zone). In the Arctic Islands Play Group, one established and three conceptual plays are discussed (Mesozoic discoveries in folds; Upper Paleozoic clastic and carbonate; Lower Paleozoic Arctic Fold Belt plays in the Parry Islands Fold Belt on Melville and Bathurst Islands and in the Cornwallis Fold Belt on eastern Bathurst Island; Arctic Stable Platform). Baffin Bay was not assessed. Compared to the 1997 assessment, the 2001 assessment makes a more complete assessment of frontier basins using all established and documented conceptual plays.

Input parameters are provided in separate documents. Input parameters for the Mackenzie-Beaufort assessment were extracted from the NEB deterministic files. The NEB's "possible" areas (P20) were used for the pool areas, based on information in the operator’s submissions and/or from interpretations of seismic and borehole data by NEB technical staff. Plays are described in detail in Chapter 12.

Constraints and/or Filters: Only assesses natural gas. Also considers Nominal Marketable Gas based on economic filters.

Assessed Resource: The assessment reports number of pools, initial gas in place, initial recoverable gas, initial marketable gas for both discovered pools and undiscovered plays. Total predicted field count for each play was based on seismic anomaly maps provided by the Geological Survey of Canada, modified by the Committee. No assessments were made for high risk conceptual plays in the Arctic Islands.

Quality: Compared to NEB and GSC methods, CGPC views risk in frontier areas as higher than the NEB so assesses lower volumes. See discussion under Procter et al. (1983), and above under (i).

iii. Natural Gas Potential in Canada 2005

Assessment Area(s): Regional study of natural gas potential of Canada. The document includes page-sized maps showing the assessment areas.

Methodology: Quantitative using Truncated Discovery Process Model (TDPM). For assessments where no new data was provided, 2001 values using PETRIMES were carried over.

Input parameters and play definitions: Assessments were updated to include 2002-2003 year end data.

Constraints and/or Filters: Only assess natural gas. Also considers Nominal Marketable Gas based on economic filters.

Assessed Resource: The assessment reports number of pools, initial gas in place, initial recoverable gas, and initial marketable gas for both discovered pools and undiscovered plays. Total predicted field count for each play was based on seismic anomaly maps provided by the Geological Survey of Canada, modified by the Committee. Some large undiscovered fields predicted by the software were removed at the discretion of the committee, but the logic and justification behind this decision is unclear. This is likely the reason that this assessment has the lowest predicted gas resource. No assessments were made for high risk conceptual plays in the Arctic Islands.

Quality: Compared to NEB and GSC methods, CGPC views risk in frontier areas as higher than the NEB so assesses lower volumes. See discussion under Procter et al. (1983).

1d. United States Geological Survey (USGS) Circum-Arctic Resource Appraisal, 2008.

Assessment Area(s): The USGS Circum-Arctic appraisal was part of the USGS Global assessment of hydrocarbon resources. Assessment units (AUs) were based on the map of Arctic sedimentary basins subsequently published by Grantz et al. (2011). Four assessment units were considered in the Canadian Arctic: Amerasia Basin, Sverdrup Basin, Franklinian Shelf, and West-Greenland-East Canada. The assessment units do not follow political boundaries; for instance, West-Greenland-East Canada aggregates resources on the Greenland and Baffin sides of Baffin Bay. The Amerasia Basin assessment unit includes Mackenzie-Beaufort regions as well as the Canada Basin. The Sverdrup Basin assessment unit includes Banks Island and the continental margin. Note that the Banks and Eglinton basins are included as part of the Arctic Margin assessment unit, in contrast to the detailed USGS assessment of the western Arctic region (ref.3a. USGS, 2012) that includes the Banks and Eglinton basins as part of the Sverdrup assessment unit.

The document has a number of associated publications. The publications that post- date the 2008 release provide more detailed input parameters, methods, and model results (F5-F50-F95 cases).

Year	Synonymous Publications	Author (s)
2020	Geology and Assessment of Undiscovered Oil and Gas Resources of the Sverdrup Basin Province, Arctic Canada, 2008	Tennyson, M.E. and Pitman, J.K.
2020	Geology and Assessment of Undiscovered Oil and Gas Resources of the Amerasia Basin Province, 2008	Houseknecht, D.W., Bird, K.J., and Garrity C.P.
2019	Geology and Assessment of Undiscovered Oil and Gas Resources of the Lomonosov-Makarov Province, 2008	Moore, T.E., Bird, K.J., and Pitman, J.K.
2017	Geology and Assessment of Undiscovered Oil and Gas Resources of the West Greenland-East Canada Province, 2008	Schenk, C.J.
2012	Assessment of Undiscovered Petroleum Resources of the Amerasia Basin Petroleum Province, 2008	Houseknecht, D.W., Bird, K.J., and Garrity C.P.
2008	Circum-Arctic Resource Appraisal, 2008	USGS
2006	Assessment of Undiscovered Oil and Gas Resources of the Mackenzie Delta Province, North America, 2004	USGS Fact Sheet

Methodology: Quantitative probabilistic assessment. The evaluation considers three conditional probability distributions for: i) number of fields, ii) field size, and iii) oil/gas ratio. These probability distributions are based either on data from the basin or on analogues from the USGS World Analogue Database (Charpentier et al. 2007). Assessment units from the USGS World Analogue Database are classified by tectonic setting, source rock age, structural style, etc, then populated with oil and gas data available from a commercial supplier (IHS). Each Arctic AU is matched to analogues from the Global Analogue Database having similar geological properties. The number of fields is estimated from fields-per-unit area in analogues. Field size distribution assumes a lognormal distribution. The minimum field size is used as the lower boundary, the median of the field size distribution is estimated from the analogues, whereas the upper bound is estimated using (1) the discovery history, (2) the largest structures on seismic images, and (3) maximum field size in the analog set.

Each assessment unit is assigned an Assessment Unit Probability (i.e., geological risk), consisting of the product of: i) charge (source and maturity), ii) rocks (reservoir, trap and seal), and iii) timing (relative timing of trap formation and hydrocarbon migration and preservation). If the Assessment Unit Probability is less than 10%, then the area is not further assessed because the chance of finding a 50 Mbbl field is small.

The three distributions (number of fields, field size, oil/gas ratio) are sampled using a Monte Carlo simulation 50 000 times to predict a size distribution. The predicted size distribution is then multiplied by the Assessment Unit Probability to make a geologically risked size distribution. Methodology is presented in detail in Charpentier (2008) and Schuenemeyer and Gautier (2010).

<u>Input parameters and play definitions</u>: The input parameters included as appendices to the reports that came out subsequent to 2008.

<u>Constraints and/or Filters</u>: Only assessed geologic units considered to have at least a 10% chance of one or more 50 Mbbl or 50 Mboe conventional oil or gas accumulations, and sedimentary basins with at least 3 km of sediment. Recoveries were based on using existing technology, but without restrictions of sea ice, water depth, or economics.

<u>Assessed Resource</u>: The Franklinian Shelf was not assessed because it is considered to have less than a 10% chance of a 50 Mbbl field. The USGS reports F (fractile) rather than P (percentile) probabilities, hence F5 rather than P5 in their reporting.

<u>Quality</u>: Inputs based on one or two boreholes in a basin, and published data. The assessment units are large and relatively little local data were considered.

1e. Petroleum and minerals management directorate, Indigenous and Northern Affairs Canada, 2008.

<u>Assessment Areas(s)</u>: All sedimentary basins of northern Canada including onshore and offshore, except for Lancaster Sound and Canada Basin.

<u>Methodology:</u> Qualitative prospectivity map showing areas of high, medium, and low hydrocarbon potential.

<u>Input parameters and play definitions:</u> None given.

<u>Constraints and/or Filters:</u> None given.

<u>Assessed Resource</u>: None cited. This a geographic assessment of petroleum potential.

<u>Quality</u>: No method given, the meanings of high, medium and low potential not given. Some choices seem anomalous, for instance, central Hudson Bay is given the same medium potential as offshore Banks Island, and the Whitehorse Trough is given a high potential, a category otherwise reserved for areas with significant discovery licences. The map does not offer much beyond that available from a generalized geological map, or map of significant discoveries.

1f. Drummond, K.J., 2009. Northern Canada distribution of ultimate oil and gas resources.

Assessment Area(s): Canada north of 60°, including some offshore areas. Of relevance to this report are estimates for the Sverdrup Basin, Mackenzie Delta, Beaufort Sea, Arctic Coastal Plain, Lancaster Basin, Baffin Shelf, Franklinian Margin, as well as Hudson and Foxe basins. Each assessment area is partitioned into onshore and offshore areas.

Methodology: Quantitative assessment using @Risk software, which performs probabilistic Monte Carlo simulations of oil and gas resource potential. No details of methodology are provided.

Foxe Basin resource was estimated by using 7% of Proctor's (ref.1a; 1984) assessment for the Hudson Platform. Drummond states that Proctor assessed both Foxe and Hudson basins, but the original files from that assessment could not be found and the final publication of Proctor makes no mention of Foxe Basin as part of the Hudson Basin assessment.

Drummond (ref.1f; 2009) apportioned the resource by onshore/offshore and by percentage in Nunavut and the percentage in NWT. The method for apportioning is based on area in each jurisdiction, and percentage of discoveries onshore vs percentage of discoveries offshore, but with adjustments for areas of each jurisdiction that Drummond considered unlikely to contain hydrocarbons (e.g., northern Ellesmere Island). Without a map showing the areal distribution of hydrocarbon prospectivity (e.g., type 4 qualitative assessment) it is likely unreliable to apportion the resource simply by area.

Input parameters and play definitions: The study is an update of a 2002 report that the author prepared for Indian and Northern Affairs. No copy of the 2002 report is available. It is also similar in many regards to Sproule Associates (2005), of which Drummond was an author. The main change in the Beaufort-Mackenzie region is an increase in the fraction of oil versus gas. This reflects the Paktoa oil discovery that was made between the dates of the two reports.

Constraints and/or Filters: None listed

Assessed Resource: Reported cases include summaries by territory, sedimentary basin, and onshore/offshore, for discovered in place and recoverable oil and gas; undiscovered recoverable oil (risked and unrisked), recoverable and marketable gas (risked and unrisked),

Quality: The report is similar in many results to Sproule Associates (2005), yet the size of some gas fields is lower. In several cases, the difference seems to be the partitioning between oil and gas (i.e., Drummond allocates more oil at the expense of gas), but in the cases of Parsons and Taglu, Drummond's assessed gas resource is 25-35% smaller than the estimate in the Sproule Associates report but without explanation.

For Foxe Basin, Drummond (Table 10) re-ran the distributions reported in Proctor et al. (ref.1a; 1984) using @Risk software. Drummond recalculated the recoverable resource for Hudson Platform as 1186 Mbbls (Proctor et al. reported 817 Mbbls for Hudson Platform). Drummond allocated 7% of the total resource to Foxe Basin, but offers no explanation for using 7%. It would appear from Proctor et al. that Foxe Basin was not assessed as part of Hudson Platform. The more recent analysis of hydrocarbon potential for Foxe Basin and Hudson Bay by Fustic et al., (ref.8a; 2018) and Hanna et al. (2018) would indicate that Foxe Basin has low potential compared to large areas of medium potential in Hudson Bay. The assessment for Foxe Basin is therefore considered unreliable.

1g. Chen et al., 2013. Assessment of yet-to-find petroleum resources of the Canadian Arctic, AAPG.

Assessment Area(s): Regional study of six Arctic offshore basins. Assessment areas shown in map view.

Methodology: Quantitative assessment using either feature counting probabilistic method where real measurements of prospect details are available; or global analogy probabilistic method was applied to regions where data are limited to regional geological information. In this case analogous areas were chosen based on having similar geological criteria, and areal yields from analogous regions were then applied to the target area.

Input parameters and play definitions: The global analogue method was applied to the Banks-Sverdrup Margin, Canada Basin, and Canadian Baffin Bay and margin. Feature counting method was applied to Beaufort-Mackenzie, Sverdrup, and Lancaster Sound basins. Inputs for the Banks-Sverdrup Margin and Canada Basin summarized.

Feature counting method uses reservoir equations for volumetric estimation. Variable dependencies were handled with copulas, and future reservoir growth was integrated into the assessment.

Constraints and/or Filters: No economic overlay. Recovery factors not given.

Assessed Resource: Mean recoverable.

Quality: The reference is a conference presentation so lacks details on inputs. The Banks-Sverdrup Margin and Canada Basin assessments are presented in more detail. Only summary numbers are given for Baffin, Lancaster Sound, and Beaufort-Mackenzie.

The Banks-Sverdrup Margin analogies and burial history models are largely based on assessing the Cretaceous to Cenozoic succession and not the underlying Paleozoic succession. The southeastern boundary of the assessment area is landward of hinge (i.e., includes areas of thin Cretaceous-Cenozoic cover) which may not be prospective for oil or gas, and which may not be representative of the analogous areas. The Sverdrup assessment area includes some, but not all, of the heavily intruded areas in the NE Arctic Islands where petroleum systems may be heavily impacted by igneous activity. The Sverdrup assessment area also includes the deeply eroded Sverdrup Rim on the NW side of the basement where Schei Point source rock are very near surface.

This report calculates substantially larger values for the resource potential of the Beaufort-Mackenzie, Sverdrup, Canada Basin, and Banks Margin regions when compared to previous GSC assessments (Proctor et al. 1984; Dixon et al., 1994; Dietrich et al., 2018), the National Energy Board (1989), Sproule Associates (2005), Drummond (2009) or the USGS (2012). This is due to a methodological change. Chen recognizes that supposedly independent input parameters are sometimes positively correlated. This concept is described in detail in a separate paper (Chen et al. 2012) in which cupolas are used to address the interdependencies. The result of using cupolas in the examples from Chen et al. (2012) is an approximately 1.6 times increase in oil resource.

1i. Dewing et al., 2022. Hydrocarbon potential map of the Canadian Arctic Archipelago and northern offshore areas, GSC Open File 8884.

Assessment Area(s): Regional qualitative assessment of hydrocarbon potential in map view. Assessment areas shown.

Methodology: Qualitative assessment based on existing qualitative assessments where available, and best judgement of GSC staff in other area.

Input parameters and play definitions: Based on published qualitative maps, extent of discoveries, seismic density, and potential field maps.+

Constraints and/or Filters: No economic overlay.

Assessed Resource: None.

Quality: Only three categories of resource potential (low, medium, high), no detailed input parameters given.

2. Beaufort-Mackenzie Delta

2d. Dixon et al., 1994. Petroleum resources of the Mackenzie Delta and Beaufort Sea.

Year	Synonymous Publications	Author (s)
2005	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 et al.
1994	Petroleum Resources of the Mackenzie Delta and Beaufort Sea, Bulletin 474	Dixon et al.
1988	Petroleum Resources of the Mackenzie Delta and Beaufort Sea, Open File 1926	Dixon et al.
1983	Petroleum Resources of the Mackenzie Delta – Beaufort Sea, Panel Report 83-03	Dietrich et al.

Assessment Area(s): Mackenzie Delta Beaufort region including the onshore Mackenzie Delta, the Tuktoyaktuk Peninsula, and offshore regions to the Yukon-Alaska border and out into the Canada Basin. The region was grouped into four geographic areas, each having distinct geological and development criteria. The document shows polygons for each play.

Methodology: Quantitative. Monte Carlo / Probabilistic using PRIMES software. GSC Bulletin 474 superseded an earlier report, GSC Open File 1926.

Input parameters and play definitions: The document provides a fairly comprehensive basin analysis based on data from 247 boreholes and 48 significant discoveries drilled to 1992. Twenty plays were considered in four geographically based play groups. These are described in detail, with probable source rock identified, ranges for reservoir parameters given, description of the structures, and exploration history. The size of significant discoveries were poorly known at the time because they had not been tested by production. Their size was estimated from probabilistic estimates using confidence levels provided by the authors, as well as published industry estimates.

Constraints and/or Filters: Part III of the publication includes an economic analysis.

Quality: Dixon et al. 1994 was a very high quality report in its day. It includes an excellent regional geological summary, as well as detailed descriptions of the plays and distributions of expected resource endowment for each play group. The weaknesses of the assessment are that is was based on older, lower quality seismic. Since that time, an extensive 2D seismic marine grid has been shot and two 3D surveys have been shot over deep water structures in compressional structures in the toe of the delta.

Dixon et al. (1994) did not include a number of conceptual plays such as natural gas in the West Beaufort Play Group or oil potential below the Tertiary in the West Beaufort Play Group. There have also been discoveries since publication of this paper, including Ellice I-48, Ellice J-27, Olivier H-01, Langley K-30, Langley E-07, and the Paktoa discovery in 2006 (240 Mbbls of oil). Paktoa oil is hosted in a trap created by a shale diapir, which was not a play type considered in the Dixon report.

2c. National Energy Board (NEB). Reasons for Decision GH-10-88 (1989); &

2e. Probabilistic estimate of hydrocarbon volumes in the Mackenzie Delta and Beaufort Sea discoveries (1998).

Assessment Area(s): Assesses the size of discovered resources in the Mackenzie Delta – Beaufort Sea region between 69°-71°N. The 1998 report expands on the resource figures given in National Energy Board "Reason for Decision GH-10-88".

Year	Related Publications and Reports	Author (s)
1998	Probabilistic Estimate of Hydrocarbon Volumes in the Mackenzie Delta and Beaufort Sea Discoveries	NEB
1989	Reasons for Decision GH-10-88	NEB

Methodology: No methodology is presented for the 1989 report. The 1998 report uses probabilistic estimates from stochastic risk analysis using @Risk add in functions in Excel using a Monte Carlo simulation.

Input parameters and play definitions: Net pay and area, porosity, and water saturation were determined from seismic or from industry information files at the NEB, and described with triangular distributions. Document contains details of the methodology, but not all the input parameters. Discoveries that were not flow tested were given an 80% chance of success. Pools within undrilled fault blocks were assigned a 50% chance of success.

Constraints and/or Filters: No Economic overlays. Porosity cut offs of 10% (sandstone) and 3% (carbonate) were used.

Assessed Resource: The 1989 report gives industry and NEB estimates for the established reserves in 15 gas fields. Discovered oil and gas resources with P95-median-mean-P5 given.

Quality: Estimates of discovered resources are uncertain because the discovery well is the only borehole in 75% of the fields; portions of discovered fields remain undrilled, and not all zones in a pool (or pools) in a field have a drillstem test. This leads to uncertainty in the exact volume of hydrocarbon that was discovered. Does not include more recent discoveries. The tables were repeated in GSC Bulletin 585 (Chapter 3, Osadetz et al., 2015).

2f. Hannigan, P.K., 2001. Petroleum Resource Assessment of the Yukon North Coast, Yukon Territory, Canada.

Assessment Areas(s): The 2001 report assessed both onshore (South Delta Mesozoic and Paleozoic, Yukon Coastal Plain) and offshore (Herschel) plays to a total of 6 conceptual and immature plays. The Coastal Plain play straddle the coast line but all wells are onshore.

Methodology: Quantitative. Hydrocarbon potential was assessed using GSC's PETRIMES assessment methodology using a lognormal approach.

Input parameters and play definitions: Play definition given, but no input parameters listed.

Constraints and/or Filters: None give.

Assessed Resource: The 2001 report gives Median estimates for undiscovered in place reserves. Diagrams show the P95-P1 probability distribution for in-place oil and gas.

Quality: The work is likely high quality given the author's access to data from the Beaufort-Mackenzie region and access to geological expertise at the Geological Survey of Canada. Petrimes software was the standard and well tested assessment software used at the GSC at the time of publication. Lack of input parameters make it impossible to assess the reliability of the tails of the distribution.

2g. Sproule Associates, 2005. Natural gas resource assessments and deliverability forecasts, Beaufort-Mackenzie and selected northern Canadian basins.

Assessment Areas(s): Regional study of basins north of 60°N. Includes Mackenzie Delta - Beaufort Sea. Previous assessments for the Canadian Arctic Islands are summarized.

Methodology: Quantitative using @Risk software. Input parameters for undiscovered resources are hydrocarbon volume (untested play area, fraction of untested play area in trap, areal fill of traps, average net pay); the yield (porosity, hydrocarbon saturation, recovery factor), and risk (probability of hydrocarbons). These input variables were given triangular distributions and sampled randomly then multiplied to generate a probabilistic estimate of undiscovered resources. Distribution of hydrocarbon volumes were predicted using a log-normal distribution of field sizes within each play and based on a cumulative frequency distribution of field sizes. Details of the methods are in the report.

Input parameters and play definitions: The 2005 report by Sproule assessed Mackenzie Delta onshore and offshore plays. Each play type is described for location and some details of the reservoir, but not linked to source rocks or other petroleum systems elements, though they are documented in Dixon et al. (Bulletin 474). Discovered resources are from operator or NEB estimates. Reservoir parameters for the Beaufort-Mackenzie Basin fields were derived from the input sheets of the NEB 1998 "Probabilistic Estimate of Hydrocarbon Volumes in the Mackenzie Delta and Beaufort Sea Discoveries". Tables of the input data are listed in appendices.

Constraints and/or Filters: The assumptions for marketable gas are extensively documented.

Assessed Resource: Reported cases are gas in place, recoverable gas, marketable gas and liquids. The size distribution for fields are documented for each play and the probabilities reported by 5% increments. Number of undiscovered fields and marketable gas are reported for bins of field sizes

Quality: High quality assessment, though input parameters were the same as NEB report and not independently assessed. Triangular distributions are defined with minimum, mode and maximum values. Triangular distributions are not observed in natural processes and most research suggests either lognormal or normal distributions of various geologic phenomena. Triangular distributions were implemented as computational and development short-cuts. They should be used with caution since right-skewed triangular distributions predict large values far more frequently than the underlying lognormal distribution and will tend to overstate the mean. Conversely, left-skewed triangular distributions will tend to understate the mean.

2h. United States Geological Survey, Assessment of Undiscovered Oil and Gas Resources of the Mackenzie Delta Province, North America, 2004.

Year	Synonymous Publications	Author (s)
2008	Circum-Arctic Resource Appraisal, 2008	USGS
2006	Assessment of Undiscovered Oil and Gas Resources of the Mackenzie Delta Province, North America, 2004	USGS Fact Sheet

Assessment Area(s): Shown in map view, bounded by the 3000 m isobaths and basin geometry related to Cenozoic delta systems. Deep-water delta not assessed.

Methodology: Quantitative as described for the 2008 Circum-Arctic Assessment above.

Input parameters and play definitions: Two total petroleum systems are recognized: Jurassic-Lower Cretaceous (one assessment unit), and Upper Cretaceous-Tertiary (four assessment units). Probable source rocks are identified. The assessment was based on information available up to 2002. No input parameters are given.

Constraints and/or Filters: Resource listed as fully risked, but no details given.

Assessed Resource: Fully risked conventional undiscovered resources for oil, gas and natural gas liquids, reported on P95, P50, P5, and mean.

Quality: The methodology used in this report is limited by the amount of input data from within the basin, and lack of transparency on inputs.

2i. Osadetz et al., 2005. 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.

Assessment Area(s): Three proposed marine protected areas were assessed in the Mackenzie Bay, Kendall Island and Kugmallit Bay areas covering 1792 km^2.

Methodology: The protected areas were assessed quantitatively based on previous published resource assessments by Dixon et al. (1994), CGPC (2001), and the NEB (1998). The protected areas are small relative to the previous assessment areas, and there is no information on the geographic distribution of resources in Dixon et al. (1994) or CGPC (2001). Osadetz et al. did not attempt to apportion the previously assessed resource into the marine protected areas. The report is mainly a summary of previous assessments and a qualitative discussion of the hydrocarbon potential in each proposed protected area.

2j. A27695-3 NEB - Reasons for Decision - Mackenzie Gas Project - GH-1-2004, Volume 2 appendix D. &

2k. National Energy Board, 2014. Assessment of Discovered Conventional Petroleum Resources in the Northwest Territories and Beaufort Sea

Year	Related Publications and Reports	Author (s)
2019	Discovered Conventional Petroleum Resources in the Northwest Territories and Beaufort Sea, NWT Open Report 2019-015	Irwin, D. and Fiess, K.M.
2014	Assessment of Discovered Conventional Petroleum Resources in the Northwest Territories and Beaufort Sea	NEB
2004	A27695-3 NEB Reasons for Decision – Mackenzie Gas Project – GH-1-2004	NEB

Assessment Area(s): The report provides estimates of discovered conventional natural gas, natural gas liquids, and crude oil within the discoveries of the Mackenzie Delta – Beaufort Sea and the Hecla gas field on Melville Island. Wells are assessed on an individual basis.

Methodology: Quantitative assessment of discovered resources based on information acquired from wells that encountered hydrocarbons. Statistical distributions were constructed using @Risk software and applied to drilled lands and adjacent undrilled lands. Symmetrical triangular distributions were assigned to all reservoir parameters. Drainage areas were based on internal mapping of pools or, where mapping was not feasible, an area of 130 hectares (644 m radius from the well) was used where a pool was penetrated by a single well outside of significant discovery lands. For oil accumulations, an area of 64 hectares was used. In faulted terrain, fault blocks adjacent to a drilled block were included with a probability of occurrence of hydrocarbons set at less than one. 5000 iterations were run.

Input parameters and play definitions: Appendix B gives gas and oil reservoir input data.

Constraints and/or Filters: Recovery factors listed in Appendix B. No economic assessment was done. Marketable refers to technically recoverable gas at surface pressures.

Assessed Resource: Reported cases are P10-P50-P90 for in-place and recoverable natural gas, natural gas liquids, and crude oil. Mackenzie Delta: P50 estimate of technically recoverable natural gas 5.7 Tcf; natural gas liquids 52.0 Mbbl; and oil 181.0 Mbbl. Beaufort Sea: technically recoverable natural gas 6.3 Tcf; NGL 1.2 Mbbl; oil 667.4 Mbbl; In-place 9.2 Tcf gas and 4917.9 Mbbl oil.

In the NWT part of the Arctic Islands, the Hecla discovery is assigned technically recoverable 2.6 Tcf of gas and 31 Mmbls of marketable oil; in place 3.8 Tcf of gas and 51.4 Mmbls oil.

Quality: The NEB assessment makes several shortcuts compared to other assessments; it uses a lower number of runs in simulations, and assumes a triangular distribution. The total discovered gas and oil estimates for a region appear to be a numerical summing of P50 values rather than mean. Summing probabilistic estimates is not statistically correct.

The estimates produced by the NEB are substantially different than operator estimates. For example, the Taglu field has different values reported by the operator (Imperial) compared to the NEB estimate (Table 4). The Imperial estimate (ref.2i; NEB report of decision GH-1-2004 p. 229) is 2.8 Tcf of recoverable gas; and 30.0 Mbbls of recoverable natural gas liquids, whereas the NEB estimate is recoverable gas of 2.1 Tcf (ref.2j, NEB 2014). The number of discovery and delineation wells is 7 according to the operator, but the NEB (ref.2j, NEB 2014) assessed 2 wells. The area of SDL063 is 6096 ha, but the maximum area assessed for the two wells by the NEB appears to be 3166 ha (i.e., the sum of the largest areas assessed in the two wells). The NEB report does not address the difference between their estimate and the operator estimate.

2l. Irwin, D. and Fiess, K.M., 2019. NWT Open Report 2019-015. Discovered conventional petroleum resources in the Northwest Territories and Beaufort Sea.

Assessment Areas(s): Northwest Territories, primarily Beaufort Sea.

Methodology: Map depiction of P50 distributions in the assessment area based on conventional discoveries.

Input parameters and play definitions: Based on NEB 2014 Appendix B reservoir data.

Constraints and/or Filters: Recovery factors listed in NEB 2014 Appendix B. No economic assessment was done.

Assessed Resource: Reports P50 ranges for initial marketable gas, initial recoverable oil, and recoverable condensate.

Quality: Refer to 2j.

3. Canada Basin

3a. Houseknecht, Bird, and Garrity, 2020. Geology and Assessment of Undiscovered Oil and Gas Resources of the Amerasia Basin Province, 2008.

Year	Synonymous Publications	Author (s)
2020	Geology and Assessment of Undiscovered Oil and Gas Resources of the Amerasia Basin Province, 2008	Houseknecht, D.W., Bird, K.J., and Garrity C.P.
2012	Assessment of Undiscovered Petroleum Resources of the Amerasia Basin Petroleum Province, 2008	Houseknecht, D.W., Bird, K.J., and Garrity C.P.
2008	Circum-Arctic Resource Appraisal, 2008	USGS

Assessment Area(s): USGS assessment of the sedimentary basins underlying the Amerasia Basin, including the deep Canada Basin, the basins along the continental margins of Alaska and Canada, and the deformed strata of the Mackenzie Delta and western Beaufort shelf. Assessment areas are shown in detailed map view and the reasons for boundary choices are explained in detail. Note that the Banks and Eglinton Basins are included as part of the Sverdrup assessment unit.

Methodology: Quantitative assessment using the basin scale global analogue USGS methodology as described in the USGS Circum-Arctic Resource Appraisal.

Input parameters: Potential source rocks are identified. Pseudowells run and presented for each basin. Risking of charge, reservoir, and timing are described in detail and quantified, the list of analogue basins given. The ranges of values for number of accumulations, oil-to-gas mix, and size distribution are given as is the reasoning for the choices.

Constraints and/or Filters: Only areas with a greater than 10% chance of a 50 Mboe field were assessed.

Assessed Resource: The Canada Basin was not assessed as it was given a less than 10% chance of hosting a 50 Mboe field. Reported cases for the other three basins are recoverable oil, associated gas, natural gas liquids, non-associated gas, and liquids at the F95-F50-F5 and mean estimates.

Quality: The USGS assessments are based on an extensive analogue database and robust methodology. This assessment is quite complete in its reporting of input parameters and why those choices were made. However, given the huge number of regional assessments that the USGS makes, they cannot assess all the available data. Some assumptions made in this report can be questioned. In particular, the assessment of the Canada Passive Margin invokes four potential source rocks based on a comparison with the Alaska Passive Margin and the Beaufort-Mackenzie Delta, and chose the location of the pseudowell at the shelf break, where the Cenozoic succession is thickest. Because the pseudowell is located where the Cenozoic is thickest, older potential source rocks (i.e., equivalents to the Jurassic Husky Formation or Ringnes-Deer Bay formations) are discounted as overmature. This would not be the case closer to the shore where Jurassic strata in synrift grabens may have some oil or gas generation potential. The USGS source rock 1 (Early Cretaceous) is a proven source rock in Alaska, but is unlikely to be present in the western Arctic where the Lower Cretaceous Isachsen Formation is dominated by sandstone and rapid sedimentation rates. Source rock 3 (Paleocene – Eureka Sound Formation) is based on the presence of Cenozoic biomarkers in oils within the Beaufort-Mackenzie Delta, however no Paleocene source has been identified in boreholes. These Cenozoic biomarkers have subsequently been attributed to leaching of biomarkers from Cenozoic coals during the upward migration of oils from source rock 2 (Turonian – Kanguk/Smoking Hills Formation; Li et al. 2010). Source rock 4 is attributed to organic rich units deposited during the Azolla Event in the Eocene. The extent of Azolla into the deeper basin has been questioned by Neville et al. (2019), so the extent of source rock 4 is unclear.

The Canada Basin was not assessed by the USGS because the high risk for reservoir associated with fine-grained basinal sediments reduced the chance of a field greater than 50 Mboe to less than 10%. This is in contrast with the assessment of Dietrich et al. (2018) who used data from a deep water boreholes in the Beaufort Sea to demonstrate that sandstone sheets have effective porosity.

3b. Dietrich et al., GSC Open File 8355 (revised), 2018. Oil and gas resource potential in the deep-water Canada Basin, Arctic Ocean.

Assessment Area(s): Canada Basin.

Methodology: Quantitative assessment using GSC play-based volumetric probability and basin-scale global analogue methods

Input parameters and play definitions: Incorporated UNCLOS seismic data and deep water boreholes. Five conceptual plays defined, of which four had sufficient data for a volumetric probability assessment (Mesozoic synrift did not have sufficient data). Four post-rift Cenozoic plays were assessed and the input parameters are listed in Appendix A. The Cenozoic plays are divided geographically to reflect different sediment thickness and the extent of the High Arctic Large Igneous Province. Plays were modelled using 1D burial history models. Ten global analogues were chosen for a global analogue assessment. Triangle distributions of areal yields for the analogue basins were generated as was a Pareto field size distribution.

Constraints and/or Filters: No economic filter was applied. Recovery factors are listed in Appendix A.

Assessed Resource: Total recoverable oil, solution gas, free gas, and combined oil equivalent at the P90, P50 and P10 levels, and probability distribution graphs are shown.

Quality: This publication postdates the USGS (Houseknecht et al., 2012) assessment of the Amerasia Basin which considered that the Canada Basin had less than a 10% chance of having a 50 Mboe field, largely due to the lack of reservoir facies. Dietrich et al. had access to UNCLOS seismic, which contained evidence that led the GSC to make a larger estimate of hydrocarbon resources. The seismic reflection data showed evidence of repeated lowstands that resulted in turbidite deposition with fan lobe and sheet deposits extending for tens to hundreds of kilometres. The authors tied these turbidites to deep water boreholes in the Beaufort Sea to establish that viable reservoir quality exists and is capable of producing oil and gas. The seismic also showed amplitude anomalies which the authors interpret as direct hydrocarbon indicators, supportive of an active petroleum system. Dietrich's P5 is about the same as Chen's (ref.1g; 2013) mean estimate.

4. Arctic Margin

4a. Chen et al. 2011. Petroleum resource potential of the rifted margin of the Beaufort Mackenzie Basin, Arctic Canada.

Assessment Area(s): Local study of the rifted margin between the Tuktoyaktuk Peninsula and the middle of Amundsen Gulf.

Methodology: Presented at the AAPG sponsored Polar Petroleum Potential conference in Halifax, 2011. The analysis is quantitative.

Input parameters and play definitions – Three plays were assessed: 1. Tertiary Structural Play; 2. Tertiary Stratigraphic Play; 3. Mesozoic Paleozoic Structural Play. Analysis was based on 122 mapped prospects. Discoveries in the Beaufort-Mackenzie Delta were used as analogues for volumetric parameters such as area, net pay, porosity etc. 1D burial history and expulsion model(s) were generated and field size probability distributions were estimated from Monte Carlo simulations.

Constraints and/or Filters: None documented.

Assessed Resource: Recoverable and In Place estimates, along with field size rank are given for the oil and gas potential of the Tertiary Structural Play. P90-P50-P10 and mean estimates are given for recoverable oil and gas for each of the three play types.

Quality: This was a conference presentation, so many details of input parameters and methodology are not reported.

5. Sverdrup Basin

5a. Panarctic Oils. Annual Report 1983; Reserve estimate sheets, 1985.

Assessment Area(s): Significant discovery licences, Sverdrup Basin.

Methodology: Quantitative volumetric, based on drill data (net pay, porosity, pressure, water saturation) and estimates of area from seismic.

Input parameters and play definitions: Porosity values are similar to the mean value reported by Hu et al. (2011) for Jurassic sands. Other input parameters are area, net pay, porosity, water saturation, and pressure and volume formation factors.

Constraints and/or Filters: Recovery for oil, gas vary slightly from well to well. Gas recovery is generally 0.8 and oil recovery 0.3.

Assessed Resource: Volumetric estimate of gas in place and oil in place, and recoverable. Several wells have a reported 'upside' potential based on uncertainty on the location of the gas/water or oil/water contact.

Quality: The largest unknowns are area, which is based on estimates from seismic mapping, and the gas/water contact. The seismic grid is widely spaced and there is no information on how the lines were migrated. The data sheets in the collections at the GSC were the basis for the discovery sizes reported in Chen et al. (2000), however these values are sometimes very different than those reported in Panarctic's 1983 annual report. For instance, the Drake fields in the data sheets have a reported total recoverable resource of 3.711 Tcf and an in place resource of 4.382 Tcf, whereas the 1983 annual report and Waylett (1990) report 5.144 Tcf and 5.305 Tcf of recoverable respectively. The difference seems to come from the location of the gas/water contact. The data sheets report an assumed g/w interface at -3930', which was the base of the productive interval in wells, whereas analysis of pressure gradients in Waylett (1990) indicate a g/w contact 56 feet lower at -3986'. The 56' down-dip extension of the reservoir applied over the area of the structure is presumably the reason for the difference in estimated resource.

The size of MacLean discovery changed over the 1980s. 1982 estimate for MacLean were 165.7 Bcf recoverable gas whereas the 1985 estimate was 450 Bcf recoverable natural gas.

Appendix 3B. Table 1. Discovered recoverable resource at each significant discovery in the Sverdrup Basin.

		1983 Panarctic Annual report			5a. Panarctic/NEB files			Waylett, 1990
Field	**Stratigraphy**	**Proved and probable Marketable gas (Bcf)**	**Possible Marketable gas (Bcf)**	**Recoverable NGL (Mbbl)**	**Recoverable Oil (Mbbls)**	**Recoverable gas (Bcf)**	**Upside recoverable gas (Bcf)**	**Ultimate recoverable (Bcf)**
Balaena	Isachsen				30.2			
Cape Allison	Heiberg				102.5	646.1		
Cape Macmillan	Awingak	76				60.8	207.0	
Cape Macmillan	Heiberg				4.7	40.1		
Char	Awingak	369	8	3.1	10.3			
Char	Heiberg					164.2		
Cisco	Awingak	452		8.6	198.8			
Cisco	Heiberg				11.7	99.4		
Drake Point E	Heiberg	5144				374.5		5305
Drake Point W	Heiberg					3105.9		
East Drake	Heiberg					230.8		
East Hecla	Heiberg	3575	145			41.0		
West Hecla	Heiberg					2977.0		
Jackson Bay	Heiberg	1074				985.5	1136.0	
King Christian	Heiberg	588				699.4		
Kristoffer Bay	Heiberg	653	454			1386.6		
Maclean	Skybattle	530		8		41.4		
Maclean	Heiberg					165.7*		
Roche Point	Upper Schei Point	427		4.3		20.9		
Roche Point	Lower Schei Point					32.0		
Sculpin	Heiberg	58				76.0		
Skate B-80	Heiberg	304		0.5	21.5	61.1		
Skate C-59	Heiberg				27.0	379.9		

Thor	Heiberg	715				394.1		
Wallis	Heiberg	98				99.4		
Whitefish	Isachsen	2404	327	36.1		114.7		
Whitefish	Awingak					748.0	1318.2	
Whitefish	Heiberg					1141.0	2256.8	

* MacLean field. 1982 estimates ‘Established’ 10.1 Bcf; ‘B.C.E. (best case estimate?) 165.7 Bcf.. 1985 estimates 450 Bcf

Appendix 3B. Table 1. (continued)

5b. Chen et al., 2000. Petroleum potential in Western Sverdrup Basin.

Year	Related Publications	Author (s)
2013	Geological risk evaluation using the Support Vector Machine with examples from the late Triassic-early Jurassic structural play western Sverdrup Basin, Canadian Arctic Archipelago	Chen et al.
2011	Using discovery process and accumulation volumetric models to improve petroleum resource assessment in Sverdrup Basin, Canadian Arctic Archipelago	Chen, Z. and Osadetz, K.G.
2004	An object-based model for predicting the locations of undiscovered oil and gas resources, Western Sverdrup Basin	Chen et al.
2000	Petroleum potential in Western Sverdrup Basin	Chen et al.

Assessment Area(s): Western Sverdrup Basin

Methodology: Discovery process model and a multivariate discovery process model that considers reservoir observations and seismic data. Measured reservoir parameters (e.g., pool area, net pay, porosity, and saturation) are then sampled probabilistically to produce field size distributions and a volumetric assessment. The results from the two methods are then compared.

Input parameters and play definitions: Only assessed Mesozoic structural plays. Inputs for discovery sizes are from Panarctic data sheets (ref.5a).

Constraints and/or Filters: Uses in place values of proven reserves, which takes the base of the productive zone as the gas/water interface. One set of reported results uses pool size restrictions.

Assessed Resource: Reported in place values at the 5, 25, 50, 75, and 95 percentiles for both methods

Quality: Chen et al. used the conservative size estimate for the size of the gas fields. For instance, their discovery process model (2011) used 3.7 Tcf of gas for the Drake field, rather than the 5.3 Tcf value reported by Waylett (1990). This will affect their final resource estimate. It is also possible that the low amplitude gas fields (Drake, Hecla, Whitefish, Cisco) have a different structural history than fields hosted in high amplitude folds such as Jackson Bay or Kristoffer Bay (Dewing et al. 2016 a, b). This would limit the integrity of the discovery process model. Chen uses 566 Bcf in-place gas for MacLean, or 453 Bcf of recoverable gas, similar to the 1985 Panarctic estimate.

5c. Chen et al., 2004. An object-based model for predicting the locations of undiscovered oil and gas resources, western Sverdrup Basin, Canada.

Assessment Area(s): Central and western Sverdrup Basin.

Methodology: Qualitative prospectivity map. Method uses an object-based stochastic model that simulates the likely locations of undiscovered petroleum accumulations by simultaneously considering geoscience information related to pool formation and the spatial correlation among petroleum accumulations. The method is described in detail in the paper.

Input parameters and play definitions: Only evaluated the Mesozoic structural play. Inputs the same as those used in Chen (2000).

Constraints and/or Filters: Only Mesozoic structural plays.

Assessed Resource: No assessed resource. Prospectivity map only.

Quality: Primarily a methodological paper that relies on statistical treatment of available data. No direct link to petroleum systems elements.

5d. Northern Oil and Gas Branch, 2010. High Arctic Hydrocarbon Potential.

Assessment Area(s): Sverdrup Basin and parts of the Franklinian Basin, area shown graphically

Methodology: Qualitative prospectivity map. Five bins are used, from Very Low to Very High. A short description of the meaning of each bin is given.

Input parameters and play definitions: No underlying data or reasons for boundaries are given, but the areas of high potential are very similar to those predicted by Chen et al., (ref.5e; 2011).

Constraints and/or Filters: None

Assessed Resource: No assessed resource. Prospectivity map only.

Quality: Lacks transparency for inputs. Does not say what plays are assessed.

5e. Chen, Z. and Osadetz, K.G., 2011. Using discovery process and accumulation volumetric models to improve petroleum resource assessment in Sverdrup Basin, Canadian Arctic Archipelago, Chapter 39.

Assessment Area(s): Central and western Sverdrup Basin

Methodology: Quantitative assessment using volumetric and discovery processes, similar to Chen et al., (2000) but with improved and updated methodology, especially for cross validation between discovery and volumetric methods.

Input parameters and play definitions: Same as in Chen et al. (2000)

Constraints and/or Filters: None

Assessed Resource: In situ resource estimates for both methods, reported at P95, P75, P50, P25 and P5 levels, as well as numbers of pools and resource potentials in size classes as estimated from the discovery process model. The discovery process predicts 112 petroleum fields, containing 29 crude oil and 110 natural gas pools. Uses the conservative size estimate for the size of the gas fields. This will affect their final resource estimate.

Quality: Uses the Panarctic data sheets, which present a conservative in place resource.

5f. Chen et al., 2013. Geological risk evaluation using the Support Vector Machine with examples from the late Triassic-early Jurassic structural play western Sverdrup Basin, Canadian Arctic Archipelago.

Assessment Area(s): Central and western Sverdrup Basin

Methodology: Qualitative prospectivity maps for differing reservoir parameters. These are incorporated into probability (heat) maps for petroleum occurrences. The method is described in detail in the paper. The Support Vector Machine approach transforms Bayesian statistics into conditional probabilities.

Input parameters and play definitions: Assessed data include porosity, net and gross ratios, source rocks, pressure, salinity, and structure.

Constraints and/or Filters: Only assessed Heiberg Group structural plays in the western Sverdrup Basin.

Assessed Resource: No assessed resource. Prospectivity map only.

Quality: The method and inputs are illustrated and clearly defined. Uses the Panarctic data sheets which present a conservative in place resource.

5g. Tennyson, M.E and Pitman, J.K., 2020. Geology and Assessment of Undiscovered Oil and Gas Resources of the Sverdrup Basin Province, Arctic Canada, 2008.

Year	Synonymous Publications	Author (s)
2020	Geology and Assessment of Undiscovered Oil and Gas Resources of the Sverdrup Basin Province, Arctic Canada, 2008	Tennyson, M.E. and Pitman, J.K.
2008	Circum-Arctic Resource Appraisal, 2008	USGS

Assessment Area(s): Sverdrup Basin. Banks and Eglinton Basins and the shallow offshore are included as part of the Sverdrup assessment unit.

Methodology: Quantitative assessment using the basin scale global analogue USGS methodology as described in the USGS Circum-Arctic Resource Appraisal.

Input parameters: Potential source rocks are identified, pseudowells run and presented for each basin. Risking of charge, reservoir, and timing are described in detail and quantified, the list of analogue basins given. The ranges of values for number of accumulations, oil-to-gas mix, size distribution are given and the reasoning for the choices given.

Constraints and/or Filters: Only areas with a greater than 10% chance of a 50 Mboe field were assessed.

Assessed Resource: Reported cases for the other three basins are recoverable oil, associated gas, natural gas liquids, non-associated gas, and liquids at the F95-F50-F5 and mean estimates.

Quality: The USGS assessments are based on an extensive analogue database and robust methodology. The largest possible undiscovered field size for the Sverdrup Basin was set at 800 Mboe and the maximum size for an undiscovered gas field was set at 1.5 Tcf. For the Sverdrup Rim-Banks Island area, the median number of undiscovered accumulations is set at 20, much lower than the analogue database would indicate (58-70). This was based on comparison with discoveries on the Barrow Arch of Alaska, but prior to the recent oil discoveries in that area. The estimated thermal maturity for the upper Paleozoic succession is much smaller than reported recently by Galloway et al. (2018).

6. High Arctic Basins

6a. Sørensen et al., 2011. Geology and petroleum potential of the Lincoln Sea Basin offshore North Greenland.

Assessment Area(s): Sedimentary basin recognized on magnetic and refraction data north of Ellesmere Island and north Greenland. Assessment area shown in map view in Sørensen et al. (Fig. 44.11, 2011), bounded to the south by the coast of Greenland, to the east by the magnetic signature of the Morris Jesup Rise and to the west where the shelf narrows north of Ellesmere Island. Part of the assessment area is in Canada.

Assumes that the three refraction seismic units correspond with the young continental terrace units of the rifted Arctic Margin; Paleozoic to Mesozoic stratigraphy correlative and lithologically similar to the Sverdrup Basin; and metasedimentary strata of the Franklinian Margin. Strata equivalent to the Sverdrup Basin are ~10 km thick.

Input parameters and play definitions: Assumes petroleum system similar to the Sverdrup Basin with Middle Triassic and Upper Jurassic source rocks and Triassic, Jurassic and Cretaceous reservoirs. One dimensional burial history models were constructed for two pseudowells. Charge is given a probability of 0.9, reservoir 1.0 and timing and preservation 0.6. A higher density of fields (15) is expected compared to the Sverdrup Basin (10) because the low level of exploration in the Sverdrup Basin is not expected to have found all pools. Field sizes are from USGS analogue database, with a maximum field size equivalent to the largest field in the Sverdrup Basin. This assessment assumes an oil:gas ratio of 1:1.

Constraints and/or Filters: Assess fields larger than 50 Mboe.

Assessed Resource: Reported cases are "mean risked resources" for oil, associated gas, non-associated gas, natural gas liquids and largest oil and gas fields. The assumption is that these are recoverable values because the comparison to Sverdrup uses recoverable values. Assessment area probability is 0.54

Quality: The assessment of 2130 million recoverable barrels of oil equivalent is within the range of 25% of Sverdrup Basin assessments, in line with the roughly one-quarter size of the Lincoln Sea basin compared to the Sverdrup. The Sørensen assessment makes a number of assumptions that remain untested:

- Assumes the presence of salt and salt structures on the basis of sediment thickness and an analogy with the Sverdrup Basin and Barents Sea. Salt in the Sverdrup basin was deposited as a broad sheet that migrated into diapirs whereas salt in the Barents Sea basins was limited to half grabens, and forms pillows rather than diapirs. There is no independent evidence of salt structures in the Lincoln Sea from aeromagnetic or gravity surveys.
- Assumptions about oil:gas ratio are based on the assumed loss of gas and oil in the Sverdrup Basin. Leaking seal at Balaena, described by Waylett and Embry (1993) are atypical in the Sverdrup Basin and should not taken as widespread evidence of hydrocarbon loss, and there is no evidence of oil loss due to expansion (i.e., the fields are not filled to spill). Sørensen's assumption of 1:1 gas:oil ratio is highly speculative.

- Thicker preserved young (Cretaceous and younger) strata inferred for the Lincoln Sea compared to Sverdrup Basin implies less denudation in Cenozoic time.
- Both Oakey and Stephenson (2008) and Funck et al. (2011) show a basement high between the north and south sides of the Lincoln Sea. Sverdrup-like stratigraphy is missing over the high. This could reduce the area of effective petroleum systems.
- Maximum field density used by Sørensen is 50% higher than is demonstrated for the Sverdrup Basin.
- The Lincoln Sea is on the margin of HALIP so it might be expected to be at least locally intruded, affecting both charge (possible destruction of source due to local igneous heat sources, or possible creation of local maturation) and reservoir (due to cementation associated with circulating fluids). The effect of igneous intrusions on the hydrocarbon potential of the Sverdrup Basin is complex (Goodarzi et al. 2019), but igneous activity should be reflected in a lower chance of success for charge and reservoir.

6b. Moore et al. 2011. Lomonosov Ridge microcontinent.

Assessment Area(s): The Lomonosov Ridge assessment area is underlain by continental crust and associated continental slope successions that lie on a bathymetric high between the oceanic Eurasia and Amerasia basins. The limits of the Lomonosov Ridge is based on bathymetric, magnetic, and gravity data. The details of each boundary are discussed in detail. The assessment area is shown in map view.

Methodology: Quantitative probabilistic assessment based on USGS methodology documented in Charpentier and Gautier (2011).

Input parameters and play definitions: 0.5 to 2 km of low velocity sediments are interpreted as Cenozoic. Faulted and tilted strata with higher velocities below the unconformity are interpreted as 0.5-0.8 km of Mesozoic strata, and underlain by 0.8-1.6 km of older Mesozoic or Paleozoic strata. Regional facies trends indicate the possibility of Triassic-Jurassic source rocks in the central and Canadian parts of the Lomonosov Ridge. Maps of inferred source rock distribution are presented in their Fig. 49.8. Three burial history models are presented for pseudowells. The main plays are in the Mesozoic shelf succession and the deep water Jurassic-Cretaceous passive margin succession along the Amerasian side of the Lomonosov Ridge. Two assessment areas are defined, passive-margin sequence and the Lomonosov Ridge. The assessment of the passive-margin sequence used probabilities of 0.4, 0.5, and 0.7 for charge, reservoirs, and timing. The assessment of the Lomonosov Ridge area used probabilities of 0.5, 0.7 and 0.2 for charge, reservoirs and timing. The Lomonosov Ridge assessment area was not quantitatively assessed because it was considered to have <10% chance of having a field larger than 50 Mboe.

Constraints and/or Filters: Assess fields larger than 50 Mboe or 300 Bcf of gas only.

Assessed Resource: Risked mean undiscovered resource along with P5 and P95 estimates.

Quality: There is very little geological data from the region, making stratigraphy uncertain. The reporting is inconsistent. The abstract reports risked mean values of 123 Mbbls of oil and 740 Bcf of gas, whereas the text (p. 766) reports 123 Mmbls of oil and 193 Bcf of non-associated gas. This appears to be an error;

the subsequent publication on the Makarov Basin by Moore et al. (2019; see next entry) lists 123 Mbbl oil, 193 Bcf of associated gas and 741 Bcf of non-associated gas.

6c. Moore et al. (2019) Geology and assessment of undiscovered oil and gas resources of the Lomonosov-Makarov Province.

Year	Related Publications	Author (s)
2019	Geology and Assessment of Undiscovered Oil and Gas Resources of the Lomonosov-Makarov Province, 2008	Moore, T.E., Bird, K.J., and Pitman, J.K.
2011	Lomonosov Ridge microcontinent	Moore et al.
2008	Circum-Arctic Resource Appraisal, 2008	USGS

Assessment Area(s): The Lomonosov Ridge assessment unit is underlain by continental crust and associated continental slope successions that lie on a bathymetric high between the oceanic Eurasia and Amerasia basins. The limits of the Lomonosov assessment area is based on bathymetric, magnetic, and gravity data. The details of each boundary are discussed in detail.

Methodology: Quantitative probabilistic assessment based on USGS methodology documented in Charpentier and Gautier (2011). This paper is an update of Moore et al. (2011; see previous entry) with additional details and diagrams. While it is not clearly stated, the resource numbers appear to include oil and gas rather than oil or gas, as shown by the calculation of total mean estimate of undiscovered resource expressed as oil equivalent. This value is the (sum of mean gas)/6 + mean oil (bbls) + natural gas liquids (bbls), implying that both oil and gas are present at the same time.

Input parameters and play definitions: Inputs listed in a separate appendix 2.

Constraints and/or Filters: Assess fields larger than 50 Mboe only.

Assessed Resource: Risked mean undiscovered resource along with P5, P50, and P95 estimates and largest expected mean field size.

Quality: There is very little geological data from the region, making stratigraphy uncertain. Note the difference in values between Moore et al. (2019) and Moore et al. (2011); the values reported in 2011 are internally inconsistent. Therefore the 2019 values are taken as an accurate representation of the assessment.

6d. Lister et al., 2022. High Arctic basins petroleum potential. GSC Open File 8897

Assessment Area(s): The High Arctic Basins, including parts of the Lincoln Sea, Lomonosov Ridge, Alpha Ridge, Rifted Arctic Margin, the igneous-affect portion of the Sverdrup Basin, and deformed part of the Franklinian margin on Ellesmere Island..

Methodology: Qualitative prospectivity map. Each play has four mapped petroleum systems elements (source, reservoir, trap, and seal) with an assigned probability. The probabilities are multiplied to produce a chance of success map for each play. Play (COS) maps are then summed to produce a final chance of success map. The method is described fully in Lister et al. (2018).

Input parameters and play definitions: Lists of supporting data are provided in appendices, including literature reviewed, seismic lines, and play definitions. Fifteen plays were evaluated and these are listed in document.

Constraints and/or Filters: None

Assessed Resource: No assessed resource. Prospectivity map only.

Quality: Comprehensive report based on modern data, with the inputs fully documented as shapefiles.

7. Baffin Margin

7a. Lancaster Sound Regional Study - Map 4.1 (1981).

Assessment Area(s): The assessment area is the eastern Arctic from 73° to 99°W and 72° to 75.75°N, including north Baffin, Bylot, Somerset, Cornwallis and parts of Devon islands, plus Lancaster Sound and adjoining waterways.

Methodology: Qualitative prospectivity map with 5 bins from "No Known Hydrocarbons" to "Areas where Oil and Gas Anomalies have been Mapped". Prepared by the Non-Renewable Resources Branch of DIAND.

Input parameters and play definitions: Confidential geological and geophysical reports and maps submitted by industry under the COGLA regulations were used to generate the map, including structural and seismic data.

Constraints and/or Filters: None

Assessed Resource: No assessed resource. Prospectivity map only.

Quality: No description of input parameters because they were confidential at the time of publishing. The results are similar to the prospectivity map generated during the Marine Conservation Target Initiative (7d below).

7b. Klose et al., 1982. Petroleum exploration offshore southern Baffin Island, northern Labrador Sea, Canada.

Assessment Area(s): Significant discovery licence at Hekja O-71

Methodology: The paper describes the geology of offshore Baffin Island. The reserve estimate for the Hekja O-71 discovery is stated without explanation.

Input parameters and play definitions: None given

Constraints and/or Filters: None listed.

Assessed Resource: Minimum recoverable reserves are 2.3 Tcf.

Quality: Unknown.

7c. United States Geological Survey, 2012. Geology and Assessment of Undiscovered Oil and Gas Resources of the West Greenland-East Canada Province.

Year	Synonymous Publications	Author (s)
2017	Geology and Assessment of Undiscovered Oil and Gas Resources of the West Greenland-East Canada Province, 2008	Schenk, C.J.
2008	Circum-Arctic Resource Appraisal, 2008	USGS

Assessment Area(s): Shown in map view, includes Davis Strait, Baffin Bay, Lancaster Sound, and Nares Strait, including most of Kane Basin. Includes sedimentary rocks between the Greenland and Canadian cratons. The northern boundary is at the edge of Eurekan deformation, the southwest boundary at the northern edge of the Saglek Basin. Shown in map view.

Methodology: Quantitative as described for the 2008 Circum-Arctic Assessment above. The report contains details of petroleum systems.

Input parameters and play definitions: Five assessment areas (termed Assessment Units by the USGS) were defined within a Mesozoic-Cenozoic petroleum system. Eurekan Structures Assessment Unit includes structures affected by Paleogene compression in the northern part of the province; Northwest Greenland Rifted Margin AU includes extensional structures that developed on the West Greenland continental margin during Cretaceous and early Paleogene rifting; Northeastern Canada Rifted Margin AU includes extensional structures margin of northeastern Canada. Baffin Bay Basin AU includes the thick sedimentary section deposited on Baffin Bay Basin crust during the late Paleogene and Neogene. The Greater Ungava Fault Zone AU includes structural traps developed within the Ungava transform fault zone. Each AU with potential reservoirs and source rocks is described. A brief description of the input parameters and why they were chosen is presented, with details in an appendix

Constraints and/or Filters: Only oil or gas fields greater than 50 Mboe were considered.

Assessed Resource: Fully risked conventional undiscovered resources for oil, gas, and natural gas liquids, reported on F95, F50, F5, and mean.

Quality: Very high, with a comprehensive summary of the geological history, petroleum systems elements, sources of data, and inputs available to about 2010. The F5 value is anomalously high compared to other assessments. This appears to be due to the choice of the highest possible field size. This assessment uses 5000 Mbbls as a maximum for the field size distribution, compared to 1000 Mbbls for the USGS assessment of the Alaska Rifted Margin and 2000 Mbbls for the Canada Rifted Margin (ref.3a; USGS 2020), despite the overall similar geological settings of the Baffin and western Arctic margin. The choice of the much larger maximum size the likely cause of the much higher F5 value.

To estimate the P5 for the Canadian portion of the Baffin Margin, runs for aggradation of half of Baffin Bay, Eurekan Structure, and Ungava fault zone (i.e., half of these areas are within Canada and the is no reason to consider the Greenland or Canadian sides particularly favourable), and all of NE Canada Rifted margin were performed using Rose and Associates software. The summed P5 of all cases summed to 43 442 million barrels of oil equivalent.

Knowledge about the eastern margin of Canada from Labrador to Ellesmere Island has evolved since the publication of Schenk, with a major paper on the Baffin Fan (a large deltaic system at the mouth of Lancaster Sound; Harrison et al., 2011), on-going seismic reinterpretation as part of the Geoscience for Energy and Mineral program (Bingham-Koslowski et al., 2018), and seismic interpretation on the Greenland shelf (Gregersen et al., 2013). Schenk considered graben systems as the only geological element that would result in effective petroleum systems. Recognition of a large, post-Cretaceous delta system on the Canadian side of Baffin Bay could result in a much large resource potential than is recognized in any of the available assessments.

7d. Brent et al., 2013. Assessment of the conventional petroleum resource potential of Mesozoic and younger structural plays within the proposed national marine conservation area, Lancaster Sound, Nunavut.

Assessment Area(s): Assessment area shown in map view. Boundaries of the assessment area based on proposed marine protected area rather than geological boundaries.

Methodology: Quantitative probabilistic assessment using a "revised Geological Survey of Canada play-based subjective probability assessment method". The methods are described in detail. The probabilistic method is supported by prospect level mapping and volumetric estimates.

Input parameters and play definitions: Petroleum generation models for the deepest parts of the basin confirmed that source rock temperatures were sufficient to generate oil and gas. Seismic interpretation provided data on the size and number of mapped prospects for 16 structural closures at the basement level and 22 at Cretaceous and younger levels. These mapped prospects were used to determine size distributions. Recovery factors were based on global averages for primary and enhanced recovery. Risk in 'basement' and 'Cretaceous and younger' structural plays were assigned 16% and 20% for the chance of discovering hydrocarbons for any prospect within each of the plays. Input parameters are given and described in detail.

Stratigraphic plays within the Cretaceous and younger, and Paleozoic plays were not assessed.

Constraints and/or Filters: Oil and gas recovery factors are 60-90% for gas and 18-45% for oil. Expected (mean) volumes were calculated with recovery factors of 75% for gas and 35% for oil.

Assessed Resource: Reported oil and gas in place and recoverable at the P10-P50-P90 levels for each of the plays, along with predicted in-place size of individual pools, and how many pools are expected to exist. The largest predicted oil and gas accumulations have mean sizes of 1.26 Bbbls and 4.3 Tcf of gas. Because the Dundas structure is very large, it could hold both the oil and gas components without spilling.

Quality: This modern assessment was based on interpretation of extensive seismic grid, modern geological knowledge, and assessment of direct hydrocarbon indicators on seismic and seafloor. No local information on distribution or maturity of possible source rocks is given due to the lack of drilling, but the geological inferences on source rock distribution seem logical. The methodology and input parameters are described in detail.

7e. Atkinson et al., 2017. Qualitative assessment of petroleum potential in Lancaster Sound region, Nunavut.

Assessment Area(s): Regional study, extent shown in map view. The western extent is as far as Bathurst and Prince of Wales islands, south of Somerset Island and Admiralty Inlet, north to southern Ellesmere Island and as far east as the Canada-Greenland border.

Methodology: Qualitative prospectivity map. Each play has four mapped petroleum systems elements (source, reservoir, trap, and seal) with an assigned probability. The probabilities are multiplied to produce a chance of success map for each play. Play (COS) maps are then summed to produce a final chance of success map. The method is described fully in Lister et al. (2018).

Input parameters and play definitions: Lists of supporting data are provided in appendices, including literature reviewed, seismic lines, and play definitions. Fifteen plays were evaluated and these are listed in document.

Constraints and/or Filters: None

Assessed Resource: No assessed resource. Prospectivity map only.

Quality: Comprehensive report based on modern data, with the inputs fully documented as shapefiles.

8. Foxe Basin

8a. Fustic et al., 2018. Qualitative petroleum resource assessment of Peel Sound, Bellot Strait, Gulf of Boothia, Fury and Hecla Strait, and Foxe Basin, Nunavut.

Assessment Area(s): Regional study, extent shown in map view. The western extent is as far as Prince of Wales and northern Somerset islands, Prince Regent Inlet, Gulf of Boothia, northwestern Baffin Island, and the Foxe Basin.

Methodology: Qualitative prospectivity map. Each play has four mapped petroleum systems elements (source, reservoir, trap, and seal) with an assigned probability. The probabilities are multiplied to produce a chance of success map for each play. Play COS maps are then summed to produce a final chance of success map. The method is described fully in Lister et al. (2018).

Input parameters and play definitions: Lists of supporting data are provided in appendices, including literature reviewed, seismic lines, and play definitions. Three plays were evaluated and these are listed in document.

Constraints and/or Filters: None

Assessed Resource: No assessed resource. Prospectivity map only.

Quality: Comprehensive report based on modern data, with the inputs fully documented as shapefiles

9. Franklinian Margin

9a. Hannigan et al., 1999. F. Energy Resources and Assessment.

Assessment Area(s): Bathurst Island, Nunavut.

Methodology: Quantitative. Monte Carlo / Probabilistic using PETRIMES (Lee and Tzeng, 1993).

Input parameters and play definitions: Nine conceptual plays were identified within the Parry Islands Fold Belt and Cornwallis Fold Belt. Tables are provided for inputs used for the quantitative assessment. Probabilities and distribution curves are given for each structural and stratigraphic oil and gas plays. Includes summary discussion on Ordovician and Devonian reservoirs, seals, traps, source rocks, source rock maturation, fluid migration, and coal. Lists of supporting data are provided including interpreted reflection seismic acquired by Panarctic between 1973 and 1979 and 21 exploratory wells.

Constraints and/or Filters: None

Assessed Resource: Reports in-place P10-P50-P90 cases and mean estimates. Reported recoverable resource based on applying 30% recovery for oil and 80% for gas. Also considers and assigns a low to very high potential rating based on favourable thermal maturity, presence of proven source rocks, number of probably reservoirs, favourable trap and seal integrity, timing, presence or absence of trapped closures, and number of locally-stacked plays.

Quality: The inputs were based on industry exploration data and GSC field mapping projects on Bathurst Island in the late 1990s. The software was statistically robust, however, the lower number of Monte Carlo runs may not have accurately modelled the tails of the distribution. The assessment lacks transparency in that the original files are largely missing so the assessed areas, play definitions and input parameters are often unknown.

Acknowledgments

Thanks to Chris Lister, Sonya Dehler, Elizabeth Atkinson, and Jim Dietrich from GSC-Calgary, Nikole Bingham-Koslowski from GSC-Atlantic, and Kathy Fiess of the Northwest Territories Geological Survey for their advice, input, and comments.

References

Bingham-Koslowski, N., Dafoe, L.T., St-Onge, M.R., Haggart, J.W., and Campbell, C., 2018. Report of activities for the Baffin geological synthesis (2018), GEM-2 Baffin Project; Geological Survey of Canada, Open File 8483, 11 p.

Charpentier, R.R., 2008. Methodology for Assessment of Undiscovered Oil and Gas Resources for the 2008 Circum-Arctic Resource Appraisal; Chapter B of The 2008 Circum-Arctic Resource Appraisal, (ed.) T.E. Moore and D.L. Gautier; United States Geological Survey, Professional Paper 1824, 7 p.

Charpentier, R.R. and Gautier, D.L, 2011. US Geological Survey Circum-Arctic Resource Appraisal (CARA): introduction and summary of organization and methods; *in* Arctic Petroleum Geology, (ed.) A. M., Spencer, A. F., Embry, D.L., Gautier, A.V., Stoupakova, and K. Sørensen; Geological Society, London, Memoirs 35, p. 145-150.

Charpentier, R.R., Klett, T.R., and Attanasi, E.D, 2007. Database for Assessment Unit-Scale Analogs (Exclusive of the United States). United States Geological Survey, Open File Report 2007-1404, 61 p.

Chen, Z., Osadetz, K.G., Dixon, J., and Dietrich, J. 2012, Using copulas for implementation of variable dependencies in petroleum resource assessment: example from Beaufort-Mackenzie Basin, Canada; American Association of Petroleum Geology, v. 96, p. 439-457.

Dewing, K., Brake, V., Duchesne, M.J., Brent, T.A., and Joyce, N, 2016a. Stratigraphy and structure of the Drake Point Anticline, Sabine Peninsula Canadian Arctic Islands; Canadian Journal of Earth Sciences, v. 53, no. 12, p. 1484-1500.

Dewing, K., Springer, A., Guest, B., and Hadlari, T, 2016b. Geological evolution and hydrocarbon potential of the salt-cored Hoodoo Dome, Sverdrup Basin, Arctic Canada; Marine and Petroleum Geology, v. 71, p. 134-148.

Funck, T., Jackson, H. R., and Shimeld, J., 2011. The crustal structure of the Alpha Ridge at the transition to the Canadian Polar margin - results from a seismic refraction experiment. Journal of Geophysical Research v. 116, issue B12, B12101, p. 1-26.

Galloway, B.J., Dewing, K., and Beauchamp, B, 2018. Upper Paleozoic Hydrocarbon Systems in the Sverdrup Basin, Canadian Arctic Islands; Marine and Petroleum Geology, v. 92, p. 809-821.

Goodarzi, F., Gentzis, T., and Dewing, K., 2019. Influence of igneous intrusions on the thermal maturity of organic matter in the Sverdrup Basin, Arctic Canada; International Journal of Coal Petrology, v. 213, 103280.

Grantz, A., Scott, R.A., Drachev, S. S., Moore, T.E., and Valin, Z.C., 2011. Sedimentary successions of the Arctic Region (58–648 to 908N) that may be prospective for hydrocarbons; *in* Arctic Petroleum Geology, (ed.) A.M., Spencer, A. F., Embry, D.L., Gautier, A.V., Stoupakova, and K. Sørensen, K.; Geological Society London, Memoirs 35, p. 17–37.

Gregersen, U., Hopper, J.R., and Knutz, P.C., 2013. Basin seismic stratigraphy and aspects of prospectivity in the NE Baffin Bay, northwest Greenland; Marine and Petroleum Geology, v. 46, p. 1-18.

Hanna, M.C., Lister, C.J., Kublik, K., King, H.M., Kung, L.E., McCarthy, W.M., McDannell, K.T., and Jassim, Y, 2018. Qualitative petroleum resource potential of western Hudson Bay, Foxe Channel, and Repulse Bay, Manitoba, Nunavut, Ontario and Quebec; Geological Survey of Canada, Open File 8434, 31 p.

Harrison, J.C., Brent, T.A., and Oakey, G.N., 2011. Baffin Fan and its inverted rift system of Arctic eastern Canada: stratigraphy, tectonics and petroleum resource potential; *in* Arctic Petroleum Geology, (ed.) A.M. Spencer, D. Gautier, A. Stoupakova., A.F. Embry, and K. Sørensen; Geological Society of London, Memoir 35, p. 595-626.

Haryott, P. M. and R. M. Otis, 2009, P10/P90 – A Useful Calibration Check for Estimation of Resource Parameter Ranges, presented at the Mexican Petroleum Congress (EXPETRO 2009), Veracruz, Mexico, June 10-14, 2009.

Hu, K., and Dewing, K., 2011. Geological and geochemical data from the Canadian Arctic Islands. Part X: Core petrophysical data from petroleum exploration boreholes. Geological Survey of Canada, Open File 6669.

Jauer, C.D., 2009. Hekja O-71, a major stranded gas discovery offshore Baffin Island with seismic examples of probable gas vents. Geological Survey of Canada, Open File 6432.

Jauer, C.D., Oakey, G.N., Li, Q., 2019. Western Davis Strait, a volcanic transform margin with petroliferous features. Marine and Petroleum Geology, v. 107, p. 59-80.

Jauer, C.D., Oakey, G.N. Williams, G., and Wielens, J.B.W, 2014. Saglek Basin in the Labrador Sea, east coast Canada; stratigraphy, structure and petroleum systems. Bulletin of Canadian Petroleum Geology, v. 62, p. 232-260.

Lee P.J., and Tzeng, H.P., 1993. The petroleum exploration and evaluation system (PETRIMES) – working reference guide, version 3.0 (PC version). Geological Survey of Canada, Open File 2703.

Li, M., Chen, Z., Issler, D., Achal, S., Milovic, M., Robinson, R., 2010. New insights in the effective petroleum source rocks in the the Beaufort-Mackenzie Basin from an integrated molecular and isotope approach. AAPG International Conference and Exhibition, Calgary. Search and Discovery article 40669, 32 p.

Lister, C.J., King, H.M., Atkinson, E.A., Kung, L.E., and Nairn, R, 2018. A probability-based method to generate qualitative petroleum potential maps: adapted for and illustrated using ArcGIS; Geological Survey of Canada, Open File 8404, 50 p.

Meneley, R. 2006. Exploration in the Parry Islands and Cornwallis Fold Belts: Canadian Arctic. 2006 CSPG-CSEG-CWLS Annual Convention, Calgary AB, abstract 185S0131, p. 104-111.

Neville, L.A., Grasby, S .E. and McNeil, D.H., 2019. Limited freshwater cap in the Eocene Arctic Ocean; Scientific Reports, v. 9, no. 1, p. 1-6.

Oakey, G. N., and Stephenson, R., 2008. Crustal structure of the Innuitian region of the Arctic Canada and Greenland from gravity modelling: implication for the Palaeogene Eurekan orogen. Geophysical Journal International v. 173, p. 1039–1063.

Osadetz, K.R., Morrell, G.R., Dixon, J., Dietrich, J., Snowdon, L.R., Dallimore, S.R., and Majorowicz, J.A., 2015. Beaufort Sea-Mackenzie Delta basin: a review of conventional and nonconventional (gas hydrate) petroleum reserves and undiscovered resources; Geological Survey of Canada, Bulletin 585, 19 p.

Panarctic (1983). Corporate Annual Report. Panarctic Oils Ltd.

Rayer, F.G., 1981. Exploration prospects and future petroleum potential of the Canadian Arctic Islands; Journal of Petroleum Geology, v. 3, p. 367-412.

Schuenemeyer, J.H. and Gautier, D.L., 2010. Aggregation methodology for the circum-Arctic resource appraisal; Mathematical Geosciences, v. 42, p. 583-594.

Stuart Smith, J.H. and Wennekers, J.H.N. 1977. Geology and hydrocarbon discoveries of Canadian Arctic Islands; American Association of Petroleum Geologists Bulletin, v. 61, p. 1-27.

Waylett, D.C., 1979. Natural gas in the Arctic Islands: Discovered reserves and future potential; Journal of Petroleum Geology, v. 1, p. 21-34.

Waylett, D.C., 1990. Drake Point gas field, Canadian Arctic Islands; *in* Atlas of oil and gas fields: Structural Traps I – tectonic fold traps, (ed.) E.A. Beaumont and N.H. Foster; American Association of Petroleum Geologists Treatise of Petroleum Geology, p. 77-102.

Waylett, D.C. and Embry, A.F., 1993. Hydrocarbon loss from oil and gas fields of the Sverdrup Basin, Canadian Arctic Islands; *in* Arctic Geology and Petroleum Potential, (ed.) T.O. Vorren, E. Bergsager, O.A. Dahl-Stamnes, E. Holter, B. Johansen, E. Lie, and T.B. Lund; Norwegian Petroleum Society, Publication 2, p. 195-204.