Geology and Assessment of Undiscovered Oil and Gas Resources of the West Greenland-East Canada Province, 2008

Chapter J of
The 2008 Circum-Arctic Resource Appraisal

Professional Paper 1824

U.S. Department of the Interior
U.S. Geological Survey

Cover. Fishing boat in the Ilulissat Icefjord, Disko Bay, West Greenland, which is about 250 kilometers north of the Arctic Circle. The fjord is notable for its prolific iceberg production; the fast-moving tidal glacier Sermeq Kujalleq (also called Jakobshavn Isbrae) is a major outlet of the Greenland ice sheet. Photo by Flemming G. Christiansen, Geological Survey of Denmark and Greenland.

Geology and Assessment of Undiscovered Oil and Gas Resources of the West Greenland-East Canada Province, 2008

By Christopher J. Schenk

Chapter J of
The 2008 Circum-Arctic Resource Appraisal
Edited by T.E. Moore and D.L. Gautier

Professional Paper 1824

U.S. Department of the Interior
U.S. Geological Survey

U.S. Department of the Interior
RYAN K. ZINKE, Secretary

U.S. Geological Survey
William H. Werkheiser, Acting Director

U.S. Geological Survey, Reston, Virginia: 2017

For more information on the USGS—the Federal source for science about the Earth, its natural and living resources, natural hazards, and the environment—visit https://www.usgs.gov or call 1–888–ASK–USGS.

For an overview of USGS information products, including maps, imagery, and publications, visit https://store.usgs.gov.

Suggested citation:
Schenk, C.J., 2017, Geology and assessment of undiscovered oil and gas resources of the West Greenland-East Canada Province, 2008, chap. J *of* Moore, T.E., and Gautier, D.L., eds., The 2008 Circum-Arctic Resource Appraisal: U.S. Geological Survey Professional Paper 1824, 31 p., https://doi.org/10.3133/pp1824J.

ISSN 2330-7102 (online)

The 2008 Circum-Arctic Resource Appraisal

Chapters

North Atlantic Ocean

Eurasia

Arctic Ocean

Contents

Appendixes

[Available for download at https://doi.org/10.3133/pp1824J]

Figures

Table

Chapter J

Geology and Assessment of Undiscovered Oil and Gas Resources of the West Greenland-East Canada Province, 2008

By Christopher J. Schenk

Abstract

The U.S. Geological Survey (USGS) recently assessed the potential for undiscovered oil and gas resources of the West Greenland-East Canada Province as part of the USGS Circum-Arctic Resource Appraisal program. The province lies in the offshore area between western Greenland and eastern Canada and includes Baffin Bay, Davis Strait, Lancaster Sound, and Nares Strait west of, and including, part of Kane Basin. A series of major tectonic events led to the formation of several distinct structural domains that are the geologic basis for defining five assessment units (AU) in the province, all of which are within the Mesozoic-Cenozoic Composite Total Petroleum System (TPS). Potential petroleum source rocks within the TPS include strata of Ordovician, Lower and Upper Cretaceous, and Paleogene ages. The five AUs defined for this study—the Eurekan Structures AU, Northwest Greenland Rifted Margin AU, Northeast Canada Rifted Margin AU, Baffin Bay Basin AU, and the Greater Ungava Fault Zone AU—encompass the entire province and were assessed for undiscovered, technically recoverable resources. The estimated mean volumes of undiscovered resources for the West Greenland-East Canada Province are 10.7 billion barrels of oil, 75 trillion cubic feet of gas, and 1.7 billion barrels of natural gas liquids. For the part of the province that is north of the Arctic Circle, the estimated mean volumes of these undiscovered resources are 7.3 billion barrels of oil, 52 trillion cubic feet of natural gas, and 1.1 billion barrels of natural-gas liquids.

West Greenland-East Canada Province Description

Province Boundary Definition

The West Greenland-East Canada Province, as defined for this study, encompasses an area of about 940,000 km^2 and includes Davis Strait, Baffin Bay, Lancaster Sound, and Nares Strait west of, and including, most of Kane Basin (fig. 1). The province includes the area of sedimentary rock between the Greenland craton on the east and the Canadian craton on the west. The boundary was drawn to include all areas having potential for undiscovered petroleum resources, as follows: (1) the north boundary was drawn at the edge of the tectonic zone marked by the mostly onshore fold and thrust belt of Eurekan age; (2) the southwest boundary was drawn for this study at the northern edge of the Saglek Basin that delimits the north boundary of the Labrador continental margin; (3) the southern boundary was drawn at the northern boundary of transitional crust associated with the Labrador Sea; and (5) the southeastern boundary was an arbitrary line separating a southwestern Greenland continental margin from the northwestern Greenland continental margin. As drawn, portions of the province, Total Petroleum System, and assessment units extend south of the Arctic Circle (fig. 1). The province boundary was drawn to include the area being assessed and has no political significance.

Tectonic Evolution of the West Greenland-East Canada Province

The tectonic evolution of the West Greenland-East Canada Province is complex (fig. 2) and includes multiple phases of rifting, transpressional and transtensional movement along regional transform faults, opening of Baffin Bay Basin, counterclockwise movement of Greenland away from eastern Canada as the Labrador Sea and Norwegian Sea opened along spreading ridges (fig. 3), and compression and inversion of extensional structures in the northern part of the province as Greenland rotated into Arctic Canada during the Eurekan orogeny (Grant, 1982; Reideger and others, 1984; Grant and others, 1986; Balkwill, 1987; Rowley and Lottes, 1988; DePaor and others, 1989; Roest and Srivastava, 1989; Chalmers, 1991; Chalmers and others, 1993; Chian and Louden, 1994; Jackson and Reid, 1994; Chian and others, 1995; Chalmers and Holt-Laursen, 1995; Arne and others, 1998; Chalmers and Pulvertaft, 2001; Funck and others, 2006, 2007; Geoffroy, 2001; Geoffroy and others, 2001; Saalmann and others, 2005; Wilson and others, 2006) . The kinematics of

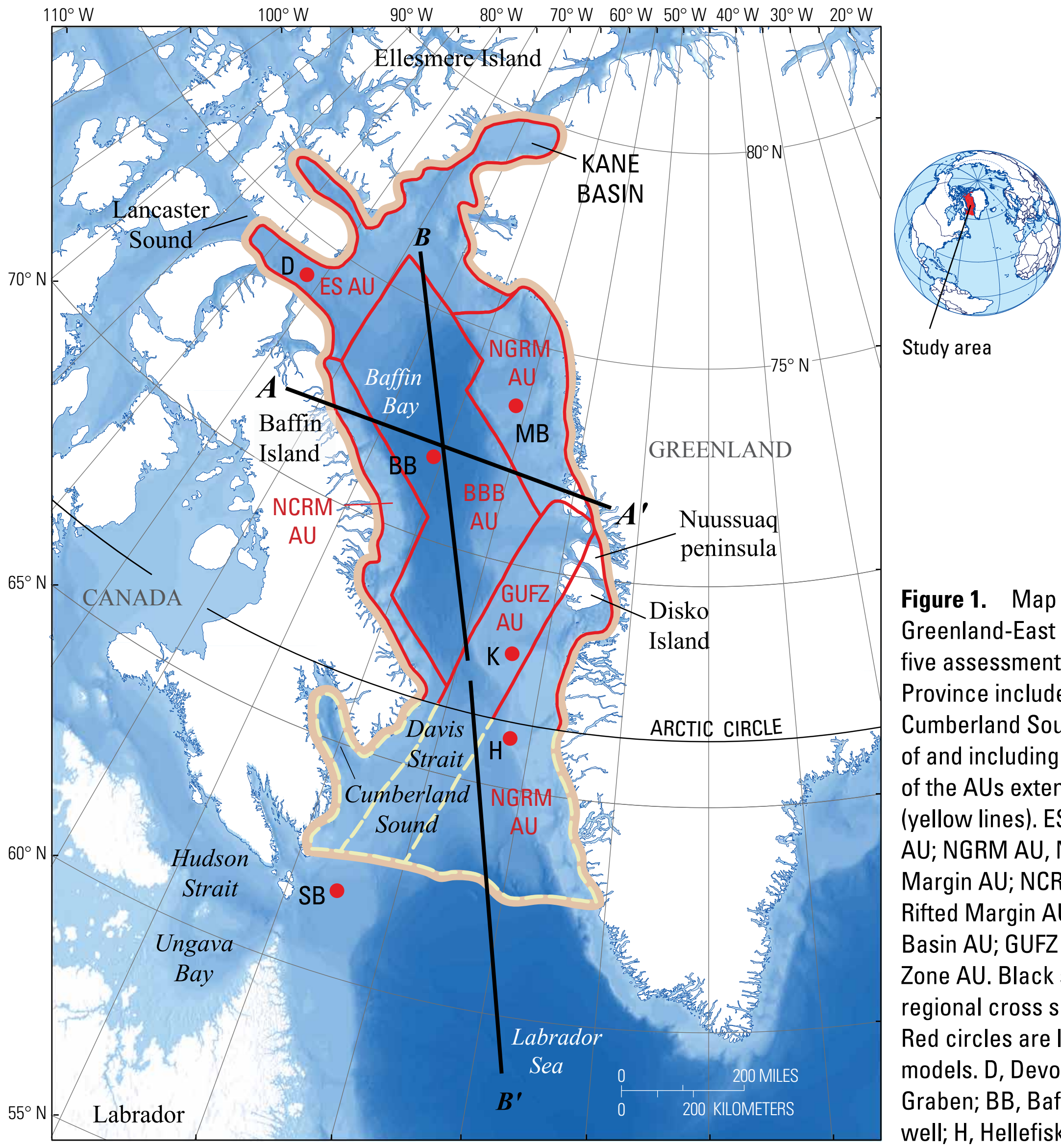

Figure 1. Map showing locations of West Greenland-East Canada Province and its five assessment units (AUs; red lines). Province includes Baffin Bay, Davis Strait, Cumberland Sound, and Nares Strait west of and including Kane Basin. Note that three of the AUs extend south of the Arctic Circle (yellow lines). ES AU, Eurekan Structures AU; NGRM AU, Northwest Greenland Rifted Margin AU; NCRM AU, Northeast Canada Rifted Margin AU; BBB AU, Baffin Bay Basin AU; GUFZ AU, Greater Ungava Fault Zone AU. Black solid lines are locations of regional cross sections shown in figure 3. Red circles are locations of burial history models. D, Devon Basin; MB, Melville Basin Graben; BB, Baffin Bay Basin; K, Kermuit well; H, Hellefisk well; SB, Saglek Basin.

the Greenland and Canada cratons were, according to Harrison and others (1999), strongly influenced by the migration and impingement of a mantle plume that caused thermal uplift and subsequent plate movements during the Neogene.

The area between Greenland and Canada might have been a zone of crustal weakness in the Precambrian, although there is no evidence of weakness at present. Paleozoic sedimentary rocks most likely were deposited across this area prior to rifting, and have been speculated as forming the deep sequence observed on seismic sections along the West Greenland margin (Chalmers and others, 1999). The significance of a possible Paleozoic section in the province is that Ordovician strata might contain petroleum source rocks and reservoir rocks.

Jurassic rifting is known from the southern Labrador Shelf in Labrador, such as the rifting event that formed the Jeanne d'Arc Basin. However, there is no evidence of Jurassic rifting in the margin of West Greenland and eastern Canada, although such rifting has been suggested (J.C. Olsen, oral comm., 2007). Rifting between Greenland and Canada first occurred in the Early Cretaceous (~140 to 130 Ma), based on synrift sedimentary sequences interpreted from the southern West Greenland and Labrador Shelf margins. Rifting was apparently related to the extension between Africa and North America to the south, and may also be related to the Thulean mantle plume (the ancestral Icelandic plume) that came into existence at that time; thermal doming associated with this mantle plume may have caused uplift and subsequent rifting between West Greenland and eastern Canada. The early Late Cretaceous was characterized by a period of thermal relaxation and subsidence (sag) and by the deposition of widespread stratigraphic units, including potential Cenomanian-Turonian and Campanian petroleum source rocks. This sag event was followed by another phase of rifting in the Late Cretaceous

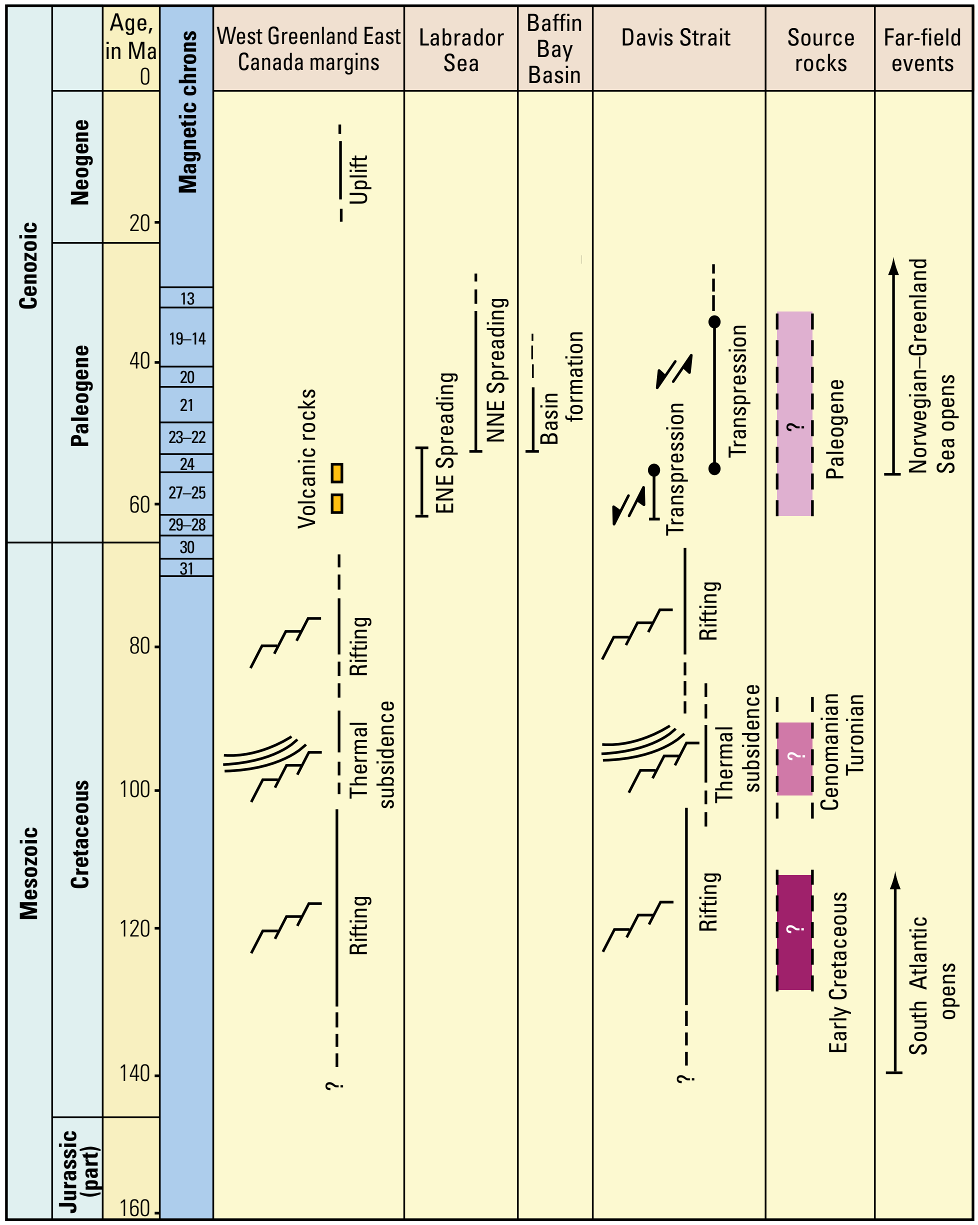

Figure 2. Diagram of the main tectonic events affecting the West Greenland-East Canada Province. Modified from Saalmann and others (2005).

and early Paleogene (Dam and others, 2000; Larsen and Pulvertaft, 2000), then again by thermal subsidence and passive margin sedimentation. The first evidence of seafloor spreading, in an east-northeast direction, was identified in Paleogene sediments (about magnetic chron 27, ~ 60 Ma) from the Labrador Sea. Seafloor spreading was followed by a change in spreading direction to north-northeast, concomitant with the development of the Ungava transform fault and the development of the postulated oceanic basin that forms the floor of Baffin Bay (between magnetic chrons 24 and 13, ~ 56–33 Ma). There is some indication that much of the tectonic evolution of this province was the result of the timing, location, and movement of the Thulean mantle plume that caused uplift, extension, and cratonic movement in the Late Cretaceous and Paleogene (Harrison and others, 1999; Funck and others, 2007). As Greenland progressively drifted north and northwest during the Paleogene and collided with northern Canada, compressional structures formed during the Eurekan orogeny. The northern part of the province is characterized by these late compressional structures, which served to invert earlier extensional structures formed during rifting (Jackson and others, 1992).

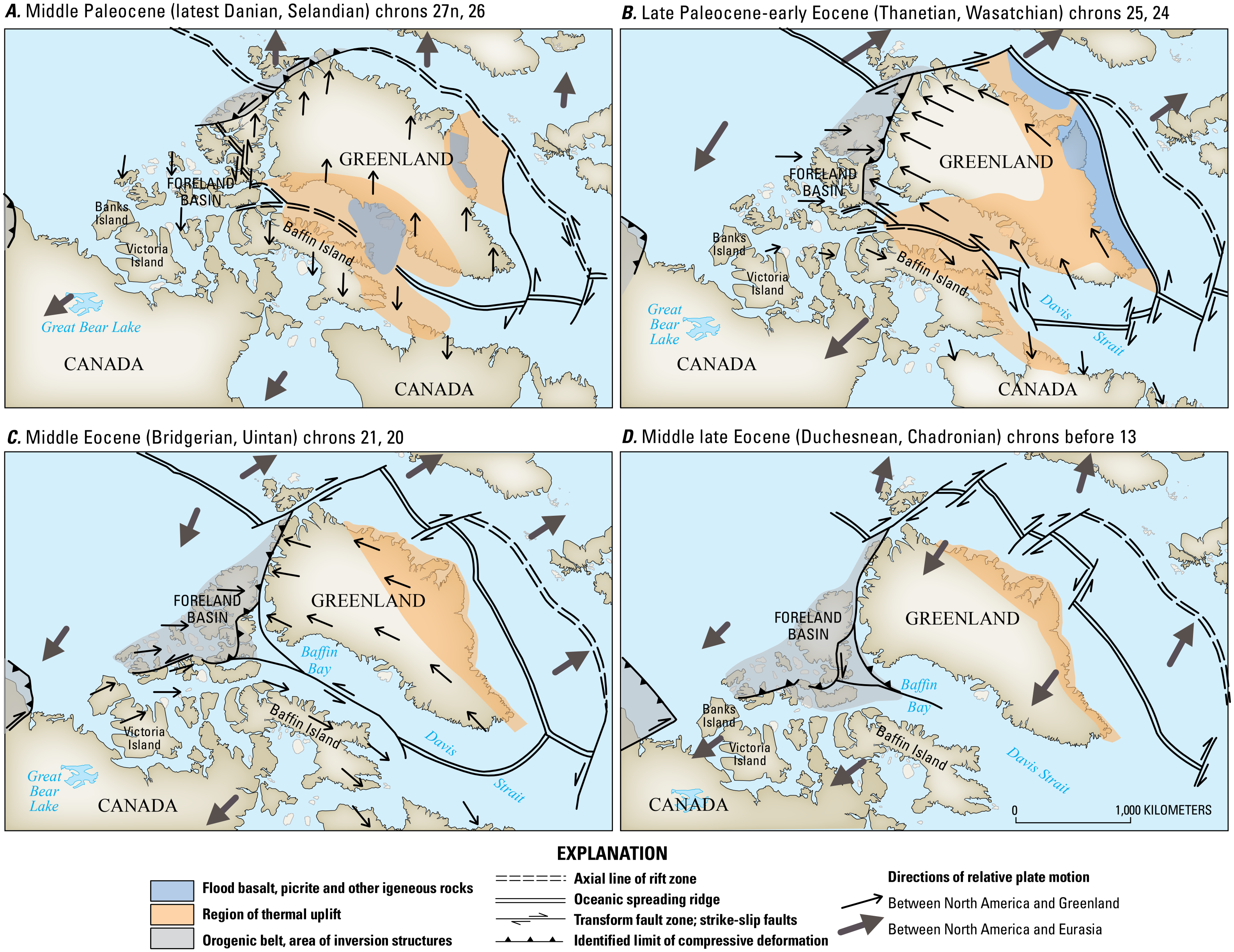

Figure 3. Schematic maps showing stages in the tectonic evolution of the West Greenland-East Canada Province. *A*, Mid-Paleocene; *B*, late Paleocene-early Eocene; *C*, middle Eocene; *D*, middle late Eocene. From Harrison and others (1999).

For this study, the West Greenland-East Canada Province was divided into five broadly defined structural domains related to important tectonic features: (1) the northern part of the province is dominated by Eurekan compressional structures; (2) the West Greenland and (3) Eastern Canada conjugate margins are dominated by rift-related extensional structures and sag-related and passive margin sediments (fig. 4); (4) the central, deeper part of Baffin Bay represents another structural domain that may or may not reflect oceanic crust or extremely thin continental crust (A. Shah, written commun., 2008) overlain by 8–14 km of Paleogene and Neogene sediments; and (5) the Ungava transform fault zone is characterized by complex structures that were initially extensional; these structures were subsequently affected by both transtension and transpression processes as the Ungava fault zone evolved into a transform zone (Sorensen, 2006; Skaarup and others, 2006). These broadly defined structural domains form the basis for the five assessment units defined in this study. The geologic evolution of these structural domains is postulated to have a direct bearing upon the potential for generation, migration, trapping, and preservation of petroleum in this province.

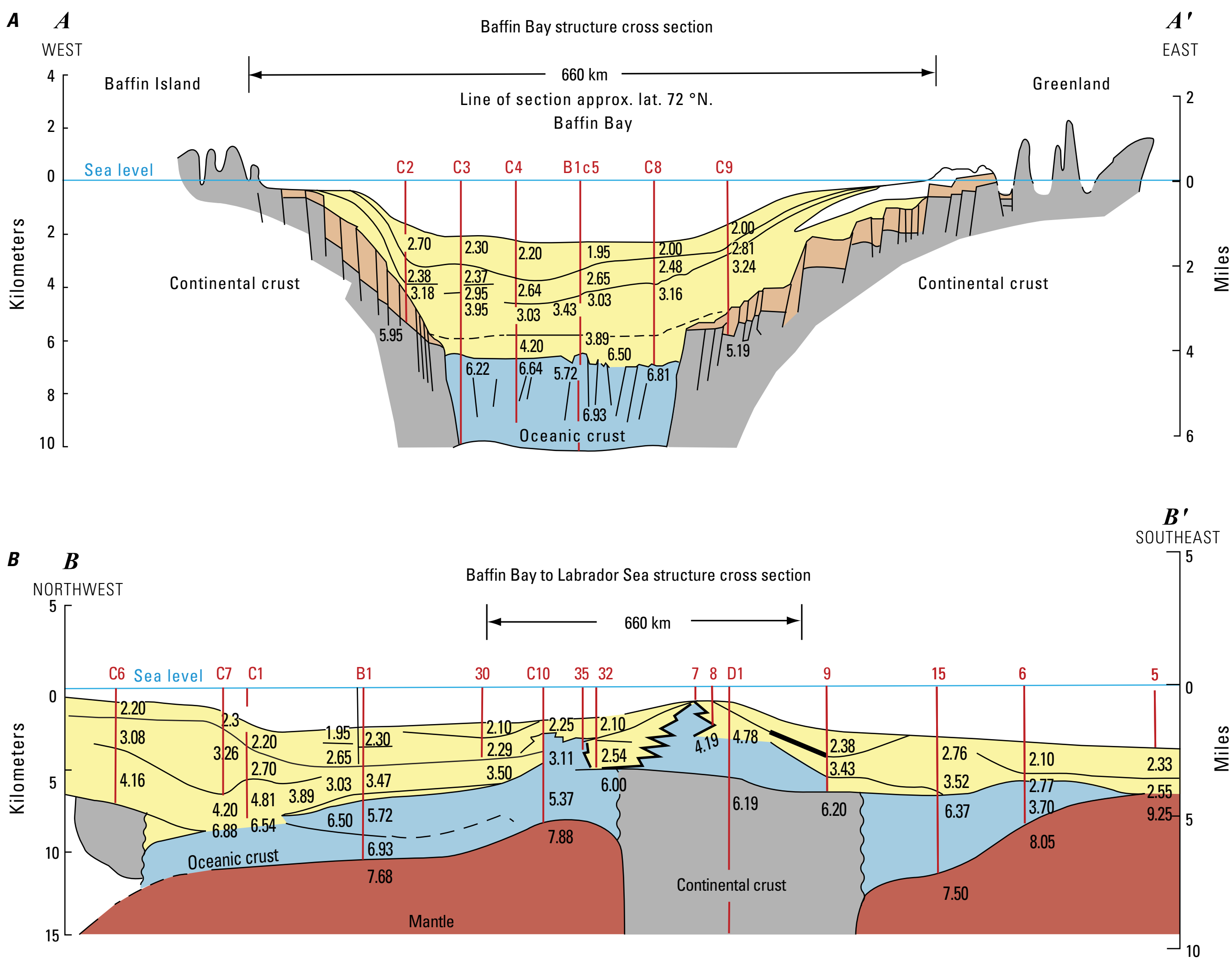

Figure 4. Regional cross sections of the West Greenland-East Canada Province. Numbers within cross sections represent seismic velocities, in kilometers per second. Lines of section shown in figure 1. From Menzies (1982).

West Greenland-East Canada Province Stratigraphy

The Cretaceous through Neogene stratigraphy reflects the tectonic evolution of the West Greenland-East Canada Province (fig. 5). Rifting in the Early Cretaceous is reflected in the lower part of the sedimentary section in which the Kitsissut and Appat sequences on the West Greenland margin and the Bjarni sequences on the southeastern part of the Canada margin reflect clastic deposition in grabens and half grabens developed when Greenland separated from Canada. Facies of this rift sequence most likely include alluvial fan, fluvial, fan-delta, deltaic, and shallow lacustrine sandstones and mudstones. Lacustrine mudstones such as those postulated on the Canada margin and coeval strata on the West Greenland margin are potential source rocks in these settings, although they have not yet been sampled by drilling.

Following rifting, thermal relaxation in the Late Cretaceous led to the sag phase, with deposition more constant and widespread across the conjugate rifted margin. The sequences developed during the sag phase include the Markland Formation on the Canada margin and the Kangeq sequence on the West Greenland margin (fig. 5). Included in these sequences are the postulated Cenomanian-Turonian and Campanian petroleum source rocks that are considered to be the most likely potential source rocks in this province. Coarse-grained clastics in the sag phase include marginal marine sandstones that have been drilled and sampled on the West Greenland margin, the so-called Fylla sandstones (Dalhoff and others, 2003). These marginal marine sandstones have excellent

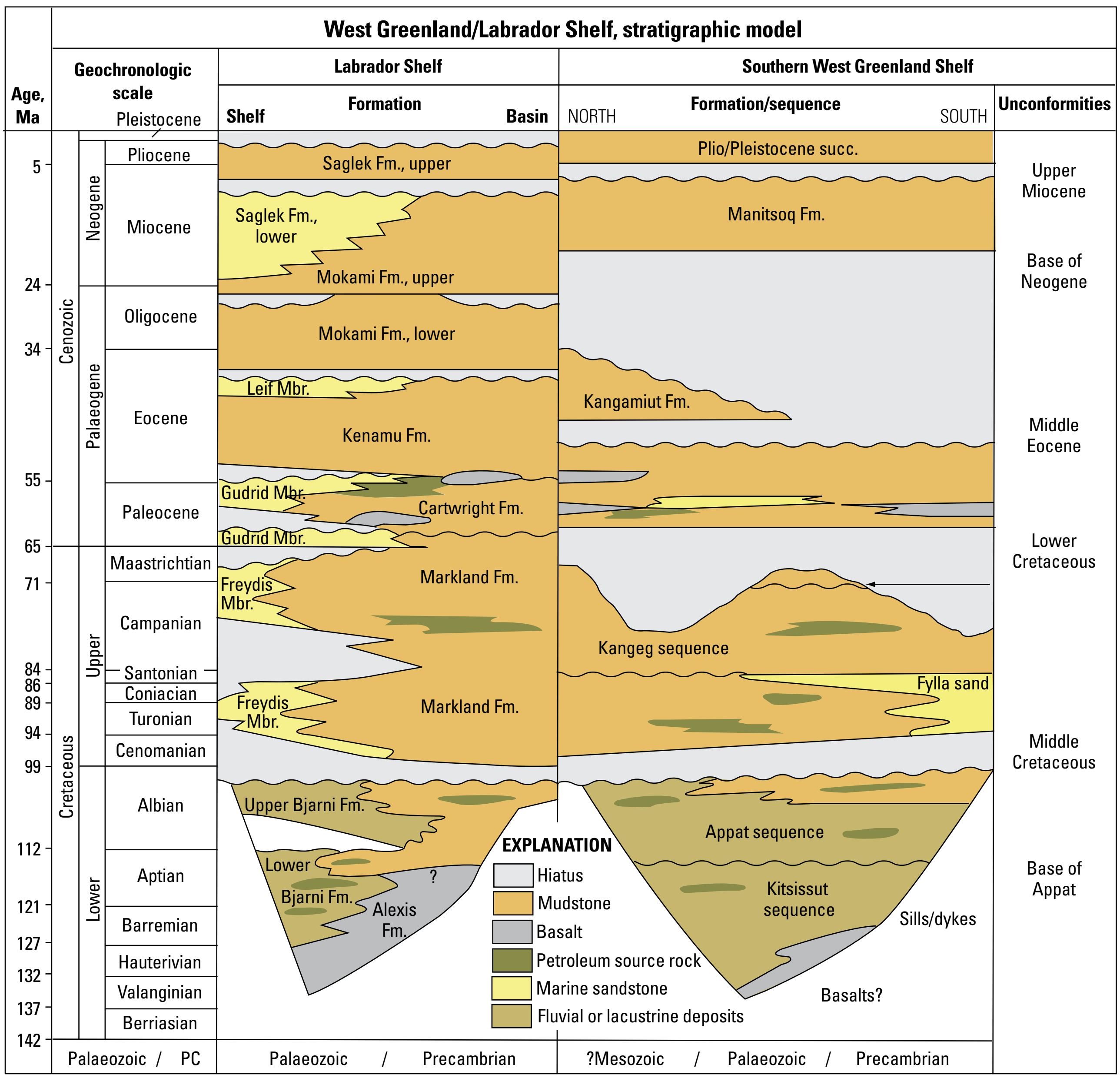

Figure 5. Stratigraphic column for the West Greenland-East Canada Province. Modified from Sorensen (2006).

reservoir properties. Deep-marine slope and fan sandstones, depositionally downdip from the Fylla sandstones, are postulated to be potential reservoirs on the margins (Dam and Sonderholm, 1994).

The Campanian-Maastrichtian sequence is largely fine-grained, and might contain potential petroleum source rocks, as well as potential reservoir rocks represented by marginal marine sandstones to deep marine slope and fan sandstones. Paleogene strata are largely fine-grained, but include several slope and fan sandstones that also might form petroleum reservoirs (Dam, 2002). Mudstones of the Campanian apparently constitute one of the most extensive seal-rock units in the province. The Paleocene was a time of widespread volcanic activity in the central part of the province, when several kilometers of plume-related volcanic rocks were extruded regionally. The Neogene was a time of widespread clastic input along passive margins of the province, indicative of Neogene uplift that has been documented from many onshore locations around the Arctic and North Atlantic (Japsen and Chalmers, 2000; Japsen and others, 2005).

Mesozoic-Cenozoic Composite Total Petroleum System

A petroleum system is defined by the extent of migration of all petroleum from a pod or pods of thermally mature petroleum source rock. With seven wells drilled in the 940,000-km^2 area of the West Greenland-East Canada Province, the definition of petroleum systems in this province is based on limited information (fig. 6). Several possible petroleum source rocks have been suggested or interpreted from geochemical data and geological arguments in the province, including Paleogene, Lower and Upper Cretaceous, and Ordovician rocks.

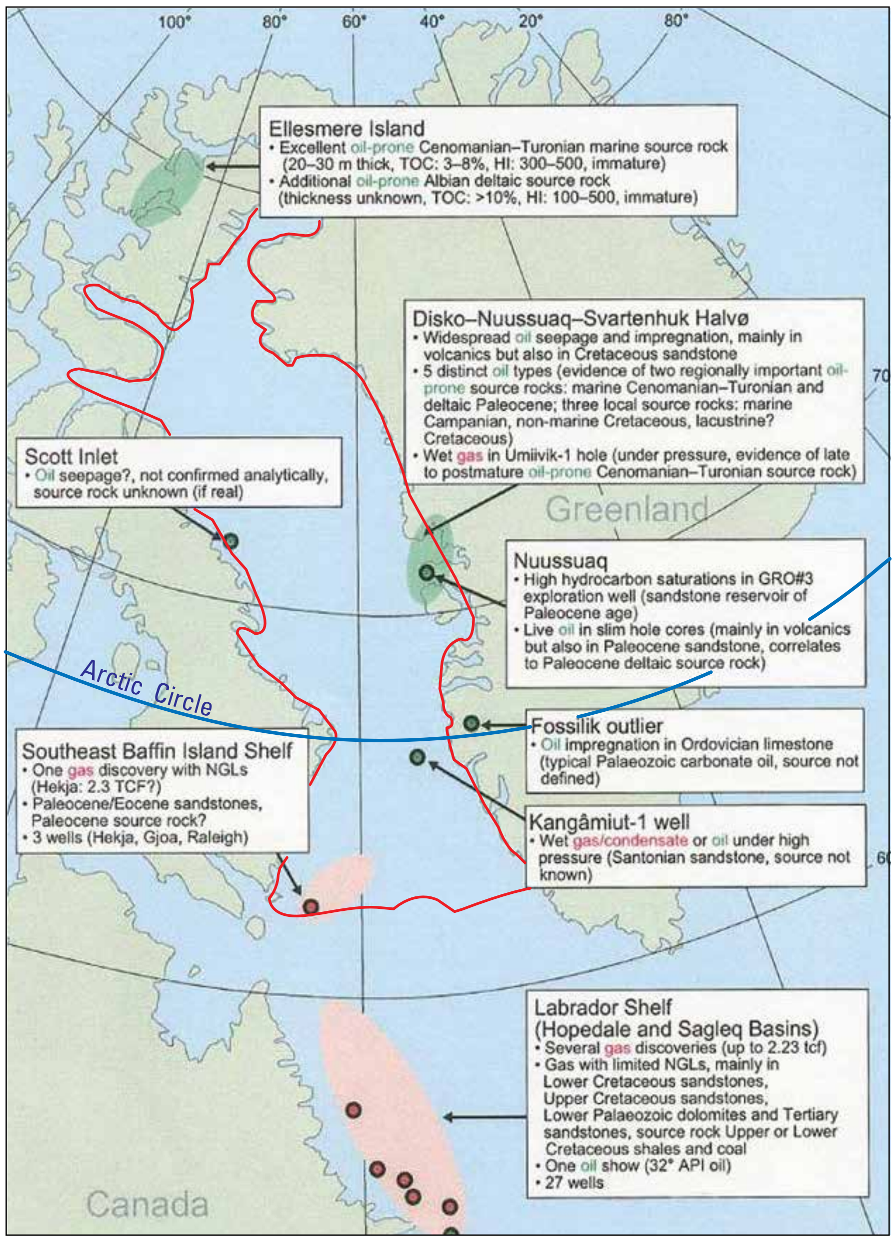

Figure 6. Total Petroleum System map for the West Greenland-East Canada Province. After Bojesen-Koefoed and others (1999).

Oil seeps described from onshore west Greenland and offshore eastern Canada provide excellent evidence that, at least in those areas, a petroleum system is or was active (Christiansen and Pulvertaft, 1994; Christiansen and others, 1996; Bojesen-Koefoed and others, 1998). An oil seep offshore of Scott Inlet in northeastern Canadian waters (Balkwill and others, 1990) has been inferred to most likely have an Upper Cretaceous marine shale source (Fowler and others, 2005), similar to the Upper Cretaceous shales of the Kanguk Formation that are exposed on Ellesmere Island.

Oil seeps and oil-stained rocks that are widely distributed in Albian to Paleogene rocks on Nuussuaq peninsula and Disko Island of West Greenland have been subjected to intensive geochemical analysis, and five oil types have been defined across this area (Bojesen-Koefoed and others, 1998, 1999, 2004, 2007; Pedersen and others, 2006). The first oil, called the Marraat oil, is considered to be the best characterized of the five oils, and is typical high wax oil sourced from a deltaic mudstone with high terrigenous organic matter content. Extracts from thermally immature Paleocene mudstones from Nuussuaq are considered correlative with the oil from the oil seeps. The second oil, the Kuugannguaq oil, is found on Disko Island, and is a high wax oil with a source interpreted to be high in terrigenous organic matter content. Biomarkers show that the oil was sourced by rocks no younger than Santonian, and the oil was interpreted to be sourced by deeply buried coals and carbonaceous mudstones of the Albian-Cenomanian Atane Formation that have been intensively studied in outcrop (Pedersen and others, 2006). The third oil recognized in the seeps, the Itilli oil, is low wax oil, typical of oil from a marine mudstone. No source rocks of this type are known from the outcrops, but the inference was made that the marine source rock might have been shale similar to the Cenomanian-Turonian Kanguk Formation such as those exposed on Ellesmere Island (Bojesen-Koefoed and others, 1998). The remaining two oils were interpreted to have local sources. Mixing of these several oils was also inferred from analyses of the seeps.

Other potential source rocks from the province have been postulated. Synrift lacustrine and (or) marine petroleum source rocks may have been deposited in Early Cretaceous grabens and may have reached thermal maturity and sourced reservoirs in the synrift section. Currently, however, there is no evidence of Early Cretaceous source rocks in this province because of a lack of drilling. It has also been speculated that rifting may have begun in this province as early as the Jurassic, and, if so, petroleum source rocks of that age could be present in these extensional structures. Further, there is the possibility that Ordovician organic-bearing shales might have been a source for petroleum in this province based on a reported dredge sample of a potential Ordovician source rock from the southeastern part of the province (GEUS, Geological Survey of Denmark and Greenland, oral commun., 2007), and a sample from an outcrop in southwest Greenland (fig. 6).

There are sufficient indications, geologically, that the principal elements of a petroleum system do exist, given the oil seeps on the margin of West Greenland. To encompass the possibility that several source rocks could have supplied petroleum to reservoirs and traps in this province, a Mesozoic-Cenozoic composite Total Petroleum System was defined to encompass the possibility that all or some of these sources have reached thermal maturity and contributed petroleum to reservoirs in the five assessment units, described below.

Assessment Unit Definitions

The assessment units defined for this study closely follow the structural domains outlined in the discussion of the tectonic evolution of the West Greenland-East Canada Province (fig. 1). The structural evolution of these areas largely affected the size, number, and timing of formation of potential petroleum traps and petroleum generation and migration. The Eurekan Structures Assessment Unit was defined to encompass all structures in the northern part of the province that were affected by Paleogene compression and inversion as Greenland rotated counterclockwise and progressively collided with Canada. The Northwest Greenland Rifted Margin Assessment Unit includes all extensional structures developed along the West Greenland continental margin during Cretaceous and early Paleogene rifting. Likewise, the Northeastern Canada Rifted Margin Assessment Unit was defined to include extensional structures of the same age along the conjugate margin of northeastern Canada. The Baffin Bay Basin AU includes potential reservoirs within the thick sedimentary section developed on Baffin Bay Basin crust during the late Paleogene and Neogene. The Greater Ungava Fault Zone AU encompasses structural traps developed within the Ungava transform fault zone. The definition of AU boundaries was based partly on a series of gravity and magnetic maps (P. Brown, written comm., 2008).

Eurekan Structures AU Description

The Eurekan Structures AU (ES AU, fig. 1) encompasses all reservoirs in traps in the northern Baffin Bay area that might have been affected by Eurekan compressional deformation. Most structures in the AU began as extensional structures in the Cretaceous and possibly were affected by strike-slip deformation associated with southwest splays of the Nares Fault System in the Paleogene. Finally, these structures were affected by compression associated with the Eurekan orogeny (Jackson and others, 1992) in the Eocene, as Greenland rotated counterclockwise and collided with Canada. The northern and southern limits of the AU are broadly defined as the limit of Eurekan compression. Total area of the Eurekan Structures AU is about 146,000 km^2, and includes most of Kane Basin, Kap York Basin, Glacier Basin, North Water Basin, Lady Ann Basin, Lancaster Sound Basin, and others (Harrison, 2005).

Geologic Model for Assessment

The geologic model for assessment of the Eurekan Structures AU largely involves Early Cretaceous and Late Cretaceous to Paleogene grabens and half-grabens filled with a typical synrift facies, including potential source and reservoir rocks (fig. 7). Upper Cretaceous sag strata may include source rocks of Cenomanian-Turonian and Campanian ages. Modeling indicates that, with burial during the passive margin phase, maturation probably commenced in early Paleogene time, followed by migration into reservoirs within structures and into stratigraphic reservoirs, including slope and fan reservoirs. Eurekan compression in the late Paleogene resulted in the inversion of some of the earlier extensional structures, possibly causing the loss of some petroleum from previous accumulations (Lowell, 1995; MacGregor, 1995). Modeling also indicates that, in addition to oil, gas generation is possible within the deeper extensional structures if source rocks are present. Assessment of geologic risk is necessarily based on the presence of adequate petroleum source rocks and on petroleum being preserved in structural traps following inversion.

Geological Analysis of Assessment Unit Probability

Charge Probability.—Several petroleum source rocks are hypothesized to be present in the West Greenland-East Canada Province (Bojesen-Koefoed and others, 1999, 2004, 2007). Postulated source rocks include organic-bearing Ordovician mudstones (Macauley and others, 1990), Lower Cretaceous synrift mudstones, Upper Cretaceous marine mudstones, and Paleogene mudstones and possibly coals. Oil seeps in West Greenland, on Nuussuaq peninsula and Disko Island, provide excellent evidence of petroleum generation from organic-bearing rocks, and the seeps include what are interpreted to be Cretaceous and Paleogene oils (Bojesen-Koefoed and others, 1999). At present there are no oil and gas discoveries or wells with shows in the Eurekan Structures AU. Outcrops of Upper Cretaceous rocks nearest to this AU that are interpreted as potential source rocks are on Ellesmere Island (fig. 4; Bojesen-Koefoed and others, 1998), and we assume that those rocks extended across this margin. The charge probability was estimated to be 0.5 for a field of minimum size (50 million barrels of oil equivalent, MMBOE) to be present within the AU. This value for charge probability was calibrated with the charge probabilities of all AUs defined within the Circum-Arctic Resource Appraisal Program.

Rocks Probability.—Structural traps have been described from the Eurekan Structures AU (Brent and others, 2006), and there is reason to believe that adequate reservoir rocks and seals are present within these structures based on limited drilling along the West Greenland margin south of this AU. The probability of adequate reservoirs rocks, traps, and seals for the presence of a minimum field size (50 MMBOE) in this AU was estimated at 1.0.

Timing and Preservation Probability.—Burial history modeling indicates that generation from potential Cretaceous source rocks possibly began in the Paleogene, and generation might continue today in some of the deeper grabens within the Eurekan Structures AU (fig. 8). Source rocks in deeper grabens might have generated earlier than indicated by the model. The main geologic risk in this AU is to what degree the compressive phase of deformation related to the Eurekan orogeny in the Paleogene affected petroleum that might have resided in structures in this AU. Compression may have resulted in the inversion of preexisting extensional structures,

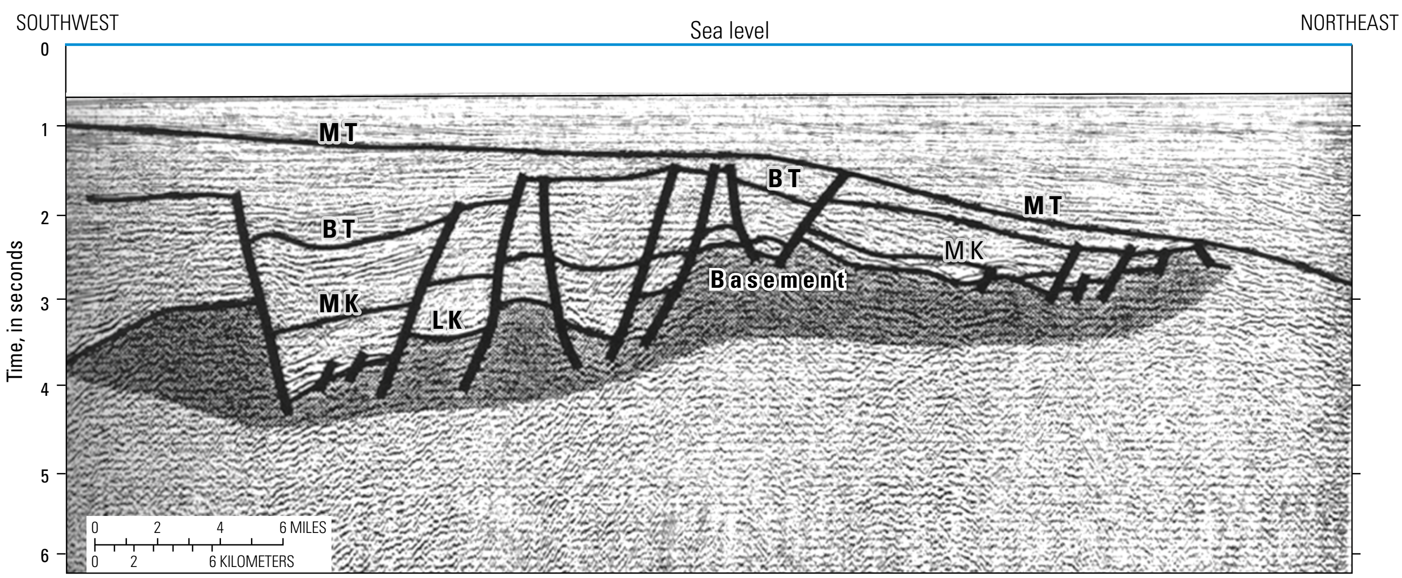

Figure 7. Seismic profile serving as a geologic model for assessment of the Eurekan Structures Assessment Unit (ES AU in fig. 1). LK, Lower Cretaceous unconformity; MK, Middle Cretaceous unconformity; BT, base Cenozoic unconformity; MT, middle Cenozoic unconformity. From Rice and Shade (1982).

thereby possibly causing re-migration of oil and gas updip from traps formed earlier. Published reports (for example, MacGregor, 1995) suggest that structural inversion could have a detrimental effect on trapped petroleum. Given this possibility—although some traps could have remained intact and unaffected—the timing and preservation probability that a field of minimum size is present within the AU was estimated at 0.5.

The geologic probability of the presence of a field of minimum size in the Eurekan Structures AU is the product of the three geologic probabilities discussed above, for an overall geologic probability of 0.25. This suggests that there is a 25 percent chance for the proper geologic conditions to form at least one oil or gas field of minimum size (50 MMBOE recoverable) in this AU. The assessment input data for this AU is summarized in appendix 1, and the basin evolution chart is in appendix 2. The events chart summarizing the elements of the petroleum system is shown in figure 9.

Estimation of Sizes and Numbers of Undiscovered Fields

The *Structural Setting-Compressional Analog Set* of the U. S. Geological Survey analog database (Charpentier and others, 2008) was used as the primary geologic analog set as a guide to the estimation of numbers and sizes of undiscovered oil and gas fields within the Eurekan Structures AU. The *World Averages Analog Set* was used as a guide for the estimation of coproduct ratios and ancillary data (see appendix 2).

Numbers of Undiscovered Oil and Gas Fields.—The median density of oil and gas fields from the *Structural Setting-Compressional Analog Set* is 0.24 fields/1,000 km^2. Given that field density and the total Eurekan Structures AU area of 146,000 km^2, the median number of undiscovered oil and gas fields greater than minimum size is estimated to be 35. The maximum number of undiscovered oil and gas fields was calculated using a field density of 1.0 fields/1,000 km^2, resulting in a maximum number of fields of 150. Using these values, the probability distribution of the number of undiscovered oil and gas fields greater than 50 MMBOE in this AU is a minimum of 1, a median of 35, and a maximum of 150. The oil/gas mix of undiscovered fields is uncertain owing to a lack of data. Limited burial history modeling indicates that oil and gas probably would be generated from the deeper grabens and extensional structures. The median oil/gas mix was estimated to be 50 percent, and the estimated range is from 10 percent at the minimum to 90 percent at the maximum. Given this distribution, the number of undiscovered oil fields was calculated to be 1 at the minimum, 16 at the median, and 135 at the maximum. The same distribution was calculated for undiscovered gas fields. Consideration was made for prospects described from this AU (Brent and others, 2006).

Sizes of Undiscovered Oil and Gas Fields.—The development of the probability distribution for undiscovered oil and gas field sizes was estimated using the *Structural Setting-Compressional Analog Set*. The median oil field size in the *Structural Setting-Compressional Analog Set* was about 120 million barrels of oil (MMBO); accordingly, this size was adopted as the median size of undiscovered oil fields in the Eurekan Structures AU. The largest expected oil field size is

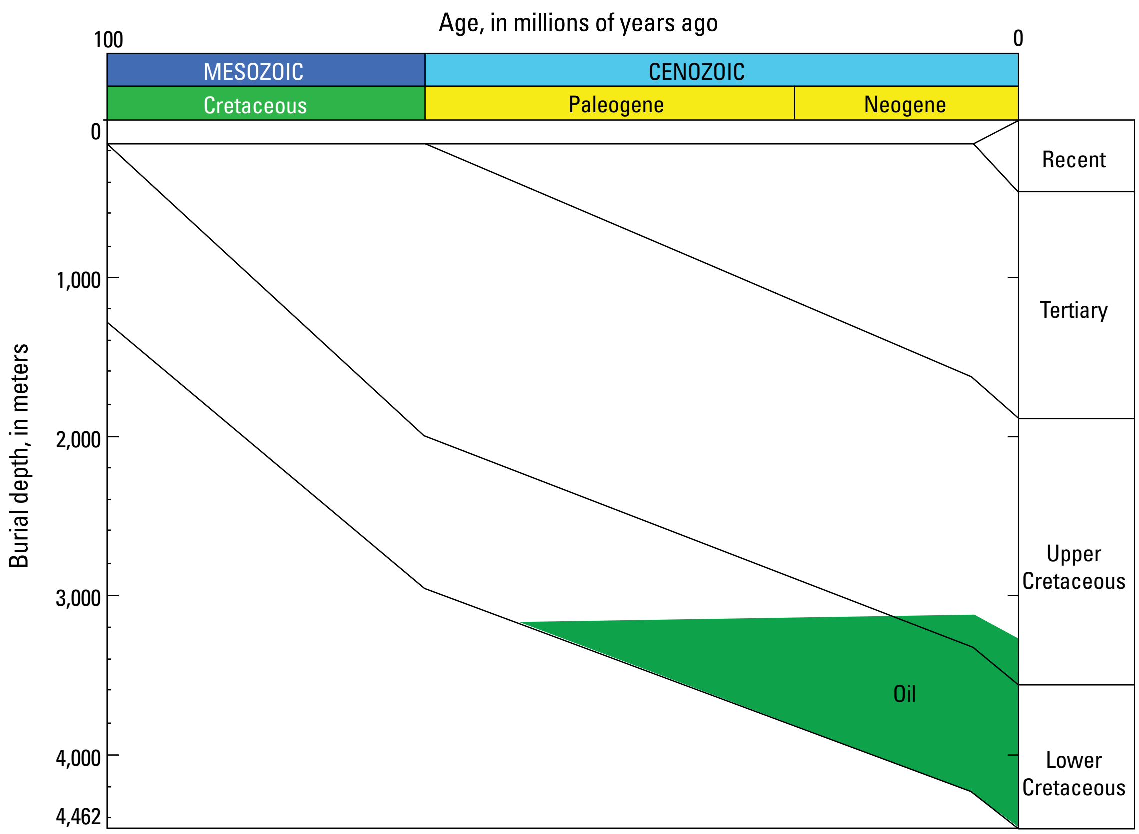

Figure 8. Burial-history diagram for the Eurekan Structures Assessment Unit (ES AU in fig. 1), based on seismic section from Smith and others (1989). Location of model is in Devon Basin, at point D in figure 1.

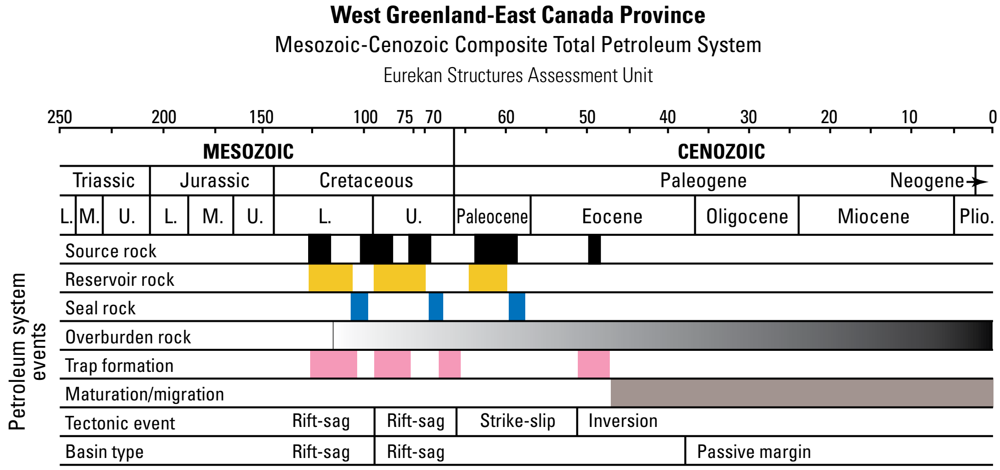

Figure 9. Total Petroleum System events chart for the Eurekan Structures Assessment Unit (ES AU in fig. 1). L., Lower; M., Middle; U., Upper; Plio., Pliocene.

estimated to be about 1 billion barrels of oil (BBO) based on the median size of the largest field sizes given in the *Structural Setting-Compressional Analog Set*. Adopting this figure for the largest expected oil field size leads to a calculated maximum oil field size (at zero probability of occurrence) of about 5 BBO. The probability distribution for undiscovered oil fields is 50 MMBO at the minimum, 120 MMBO at the median and 5 BBO at the maximum. Undiscovered gas field sizes were calculated by multiplying the undiscovered oil field sizes by 6, leading to a minimum of 300 billion cubic feet of gas (BCFG), a median of 720 BCFG, and a maximum of 30 trillion cubic feet of gas (TCFG) for undiscovered gas field sizes.

Coproduct Ratios and Ancillary Data

Estimates of coproduct ratios (gas/oil ratio, natural gas liquids (NGL)/gas ratio, liquids/gas ratio) and ancillary data for the Eurekan Structures AU were made using summaries of these data from the *World Averages Analog Set* in the world analog database (appendix 1). Using this analog set, the median gas/oil ratio was 1,000 cubic feet of gas per barrel of oil (CFG/BO), the median NGL/gas ratio was 25 barrels of natural gas liquids per million cubic feet of gas (BNGL/MMCFG), and the median liquids/gas ratio was 25 barrels of liquids per million cubic feet of gas (BLIQ/MMCFG). Drilling depths for undiscovered fields were estimated from the available seismic data, and water depths within the AU were estimated from publicly available bathymetric maps of northern Baffin Bay. Drilling depths for undiscovered oil fields ranged from a minimum of 500 m, to a median of 2,000 m, to a maximum of 5,000 m. For undiscovered gas fields, drilling depths ranged from a minimum of 500 m, to a median of 2,500 m, to a maximum of 7,000 m. Estimates of water depths for undiscovered oil and gas fields are a minimum of 0 m, a median of 600 m, and a maximum of 1,000 m.

Northwest Greenland Rifted Margin AU Description

The Northwest Greenland Rifted Margin AU (NGRM AU, fig. 1) encompasses all reservoirs in structural and stratigraphic traps along the rifted continental margin of West Greenland that were formed during rifting and post-rift thermal relaxation and sag. The AU is bounded by basement rocks of the Greenland craton to the east, the boundary of the Eurekan Structures AU to the north, the boundary of the Baffin Bay Basin AU to the west, and an arbitrary boundary to the south that is an extension of the northern limit of the Labrador Sea and the southwest Greenland margin (fig. 1). The area of the Northwest Greenland Rifted Margin AU is approximately 286,000 km^2. The AU is divided into two portions, separated by the northern end of the Greater Ungava Fault Zone AU (GUFZ AU). The boundary with the Greater Ungava Fault Zone AU is not well established, as the extent of strike-slip deformation that extends laterally from the Greater Ungava Fault Zone is uncertain.

Geologic Model for Assessment

The geologic model used for the assessment of the Northwest Greenland Rifted Margin AU includes the formation of extensional structures in the Early Cretaceous and in the Late Cretaceous-Paleogene as Greenland progressively rifted from eastern Canada (fig. 10). The numerous grabens and half-grabens mapped along this margin were filled with synrift facies that included potential petroleum source rocks and reservoir rocks. Sag-phase reservoirs of the passive margin include marginal marine to deep marine slope and fan sandstones of Cretaceous and Paleogene age (Skaarup and others, 2000, 2006; Dalhoff and others, 2003; Gregersen and Skaarup, 2007). Most likely source rocks include Cenomanian-Turonian, Campanian, and Paleogene organic-bearing strata. Petroleum generated from the maturation of source rocks during burial

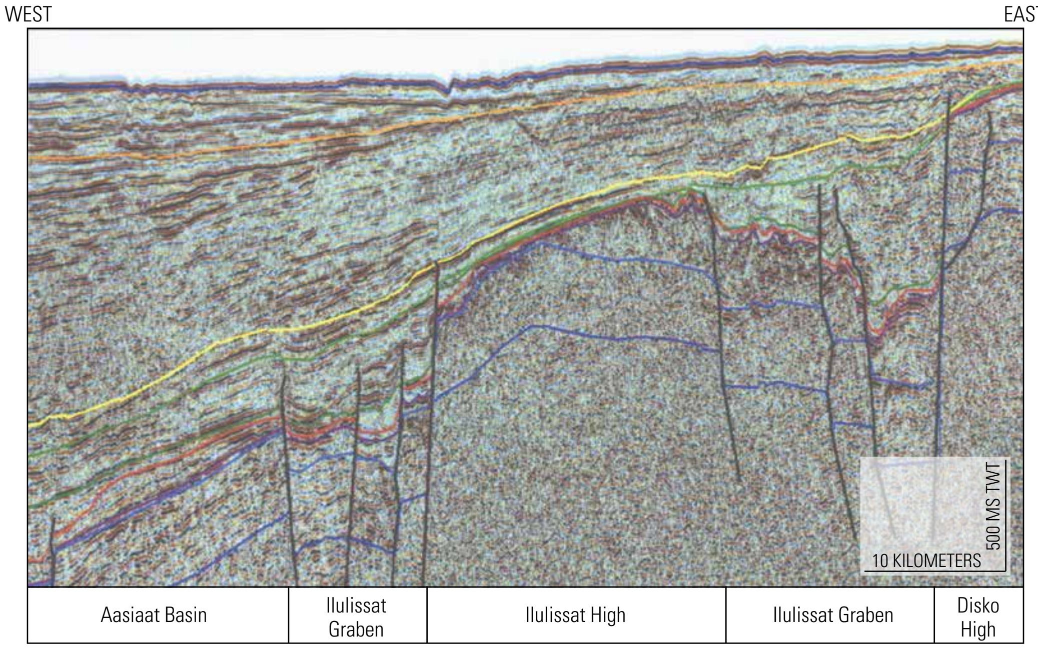

Figure 10. Seismic profile serving as geologic model for the assessment of the Northwest Greenland Rifted Margin Assessment Unit (NGRM AU, fig. 1). From Geological Survey of Denmark and Greenland (GEUS), written commun., 2007.

by synrift and passive margin sediments might have migrated into traps in extensional structures and into stratigraphic traps within the sag section. Because maturation followed trap formation, timing is not a geologic risk in this AU.

Geological Analysis of Assessment Unit Probability

Charge Probability.—Several petroleum source rocks are hypothesized to be present in the West Greenland-East Canada Province. Petroleum source rocks might include organic-bearing Ordovician mudstones, Lower Cretaceous synrift mudstones, Middle and Upper Cretaceous marine mudstones, and Paleogene mudstones. Oil seeps on Nuussuaq peninsula and Disko Island, onshore West Greenland, indicate that, at least locally, a petroleum system was or is active. Several oil types are interpreted from these seeps, including Cretaceous oils and a Paleogene oil. Four wells drilled within the Northwest Greenland Rifted Margin AU were classified as dry holes (Chalmers and Pulvertaft, 1992; Pulvertaft, 1997). The probability of the presence of source rocks to adequately charge a field of minimum size is estimated at 0.5 for this AU. This value for charge probability was calibrated against charge probability for all other AUs defined in the Circum-Arctic Resource Appraisal effort, and reflects the charge risk in AUs defined across the Arctic.

Rocks Probability.—Exploratory drilling in the Northwest Greenland Rifted Margin AU, although limited, has demonstrated that Upper Cretaceous (Santonian) sandstones exhibit excellent reservoir properties (Preuss and Dalhoff, 2001). Other potential reservoirs include nonmarine, deltaic, and shelf sandstones (Pedersen and Pulvertaft, 1992; Midtgaard, 1996; Bojesen-Koefoed and others, 2001; Pedersen and others, 2006), and Paleogene slope and basin-floor fan sandstones (Dam, 2002; Dam and Sonderholm, 1994, 1998a,b; Dam and others, 2000). A small probability also exists that Paleozoic carbonates and Lower Cretaceous sandstones with adequate reservoir properties are preserved in deeper grabens. Seals are present as intraformational mudstones, and also might be formed by the juxaposition of reservoir sandstones against basement and nonreservoir lithologies.

Timing and Preservation Probability.—Timing is not considered to be a source of geologic risk in the Northwest Greenland Rifted Margin AU. Petroleum generated in the deeper, thermally mature grabens could have migrated updip into synrift and postrift reservoirs, with no further tectonic deformation affecting the preservation of petroleum in existing traps. Timing of petroleum generation is indicated by two burial-history models, one representing the Hellefisk well (fig. 11), and the other a pseudowell modeled for the deep part of the Melville Bay graben (fig. 12). The Hellefisk model indicates that generation at the well site occurred in latest Cretaceous time, but generation would have occurred earlier in the adjacent grabens, as the well was drilled on structure. The model from Melville Bay graben indicates that generation might have begun earlier, given the thickness of strata in this graben. In addition, if the deeper part of the Melville graben contains a Paleozoic section, it is possible that Ordovician source rocks, if present, would have matured even earlier. Modeling by GEUS of several grabens in this extensional margin using extensive seismic mapping illustrates the heterogeneous maturation of potential source rocks, as the pods of mature source rocks are restricted to the grabens (fig. 13).

The geologic probability of the presence of a field of minimum size in the Northwest Greenland Rifted Margin AU is the product of the three geologic probabilities discussed above, for an overall geologic probability of 0.5. This suggests that there is a 50 percent chance for the proper geologic conditions to form at least one oil or gas field of minimum size (50 MMBOE recoverable) in this AU. The assessment input data for this AU are summarized in appendix 3, and the basin evolution chart is shown in appendix 4. The events chart summarizing the petroleum system elements in this AU is presented in figure 14.

Figure 11. Burial-history diagram for the Northwest Greenland Rifted Margin Assessment Unit (NGRM AU in fig. 1), based on data from Hellefisk well located at point H in figure 1.

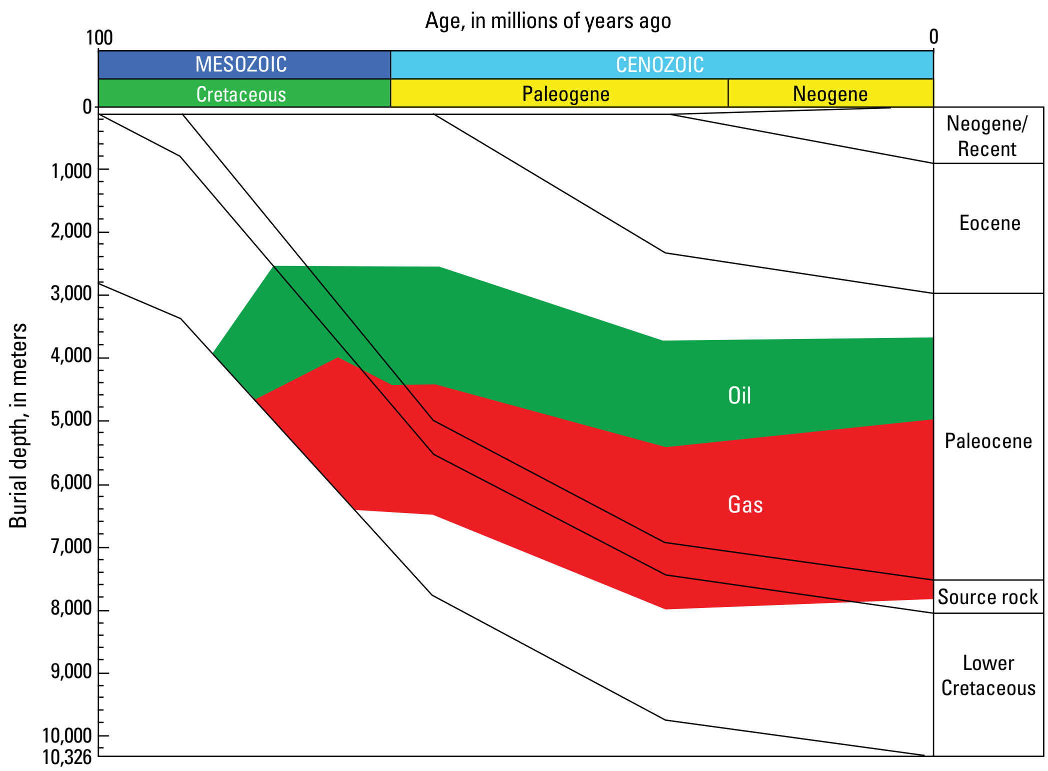

Figure 12. Burial-history diagram for the Northwest Greenland Rifted Margin Assessment Unit (NGRM AU, fig. 1), based on seismic data showing deepest part of Melville Bay Graben. Location of the modeled pseudowell is at point MB in figure 1. Seismic data from Whittaker and others (1997).

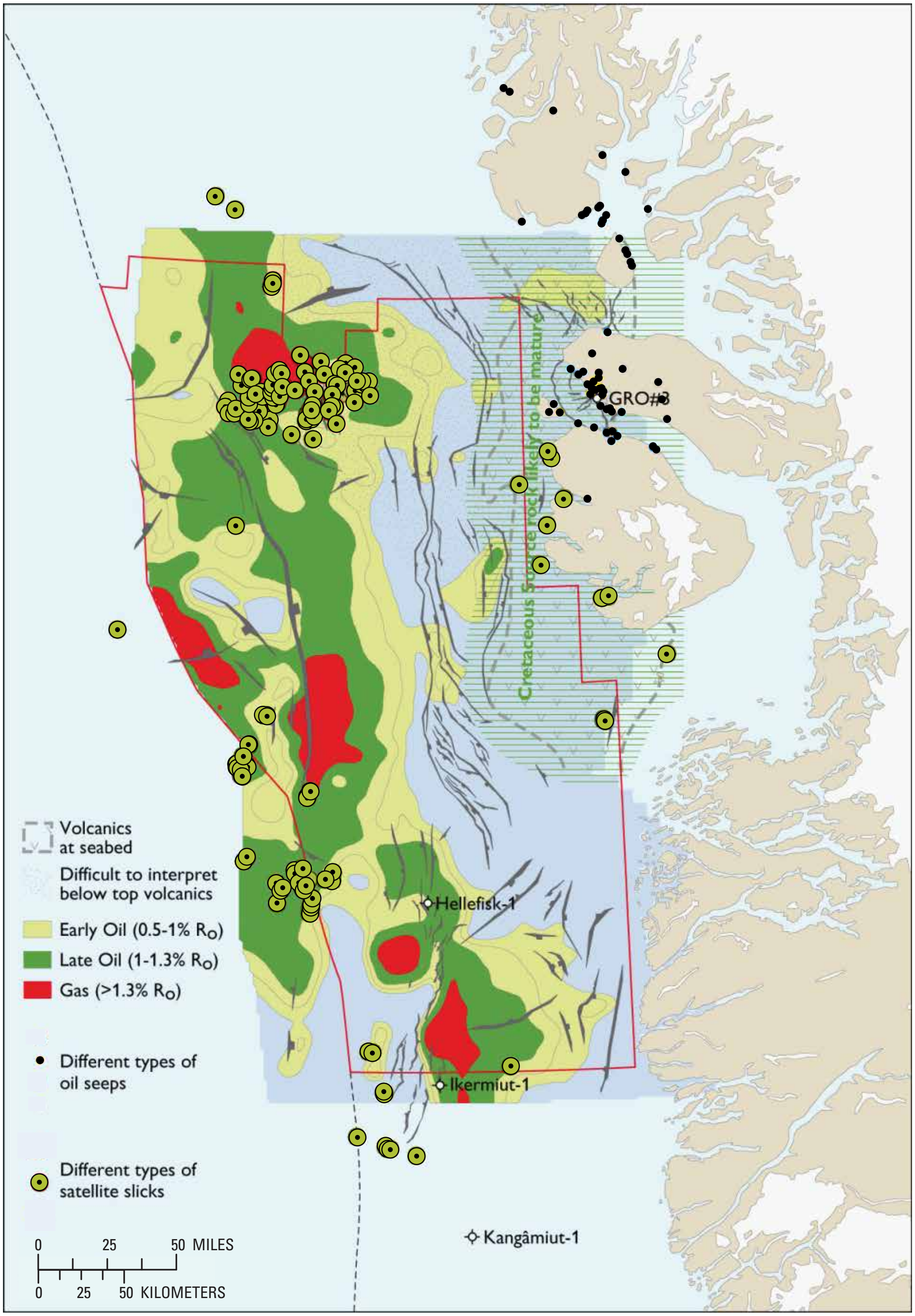

Figure 13. Modeling of thermal maturation of a series of grabens along the central part of the Northwest Greenland margin. Ro, vitrinite reflectance, in percent (%). From Geological Survey of Denmark and Greenland, written. commun., 2007.

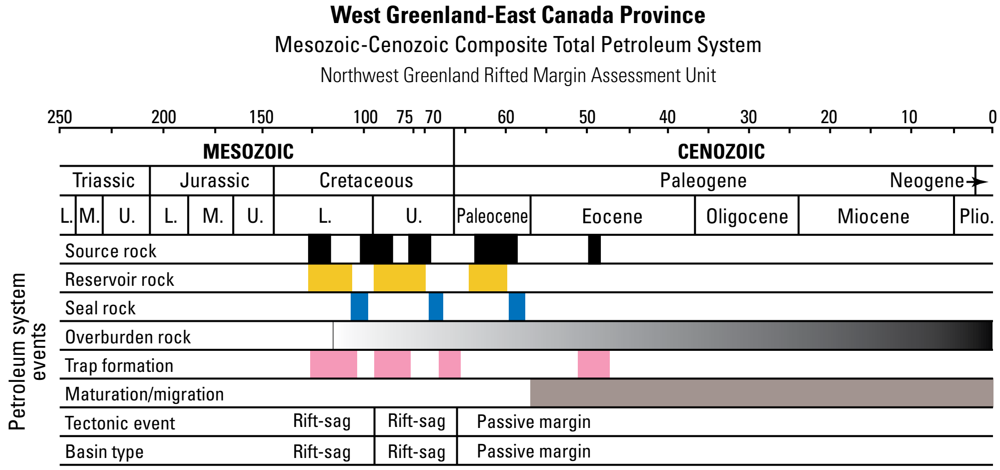

Figure 14. Total Petroleum System events chart for the Northwest Greenland Rifted Margin Assessment Unit (NGRM AU in fig. 1). L., Lower; M., Middle; U., Upper; Plio., Pliocene.

Estimation of Sizes and Numbers of Undiscovered Fields

The assessment of the Northwest Greenland Rifted Margin AU utilized the *Architecture-Rift-Sag Analog Set* from the analog database, because this set of analogs reflects the sizes and numbers of traps associated with rift-sag systems. The *Architecture-Rift-Sag Analog Set* was used to estimate numbers and sizes of undiscovered oil and gas accumulations. The coproduct ratios and the ancillary data were based on data from the *World Averages Analog Set* (see appendix 3).

Numbers of Undiscovered Oil and Gas Fields.— The distribution of numbers of undiscovered oil and gas fields is based on the density of oil and gas fields from the *Architecture-Rift-Sag Analog Set*. The median density of oil and gas fields from the *Architecture-Rift-Sag Analog Set* is 0.21 fields/1,000 km^2. Combining this figure with the Northwest Greenland Rifted Margin AU area of 286,000 km^2, the median estimate is 60 undiscovered oil and gas fields. The maximum number of undiscovered fields was calculated using a density of 0.9 fields/1,000 km^2, which yields a maximum of 250 undiscovered oil and gas fields. The distribution of undiscovered fields was 1 at the minimum, 60 at the median, and 250 at the maximum. Modeling indicates that petroleum in this AU comprises more oil than gas (Mathiesen, 2000; fig. 13), and the mode of the oil/gas mix was estimated at 60, with a minimum of 10 percent and a maximum of 90 percent reflecting the inherent uncertainties. The distribution of oil/gas mix was used to estimate 1 oil field at the minimum, 30 oil fields at the median, and 225 oil fields at the maximum; and 1 gas field at the minimum, 27 gas fields at the median, and 225 gas fields at the maximum.

Sizes of Undiscovered Oil and Gas Fields.–Sizes of undiscovered oil fields were estimated from the *Architecture-Rift-Sag Analog Set*. Median undiscovered oil field size was estimated to be 110 MMBO based on the size distribution in the analog data. The “largest expected oil field size” was estimated to be about 2 BBO, given the structures and prospects that have been mapped on seismic data in this AU and the sizes of potential “mound” prospects within the AU (Dalhoff and others, 2003). Given a “largest expected oil field size” of about 2 BBO, the maximum oil field size at zero probability is calculated to be about 10 BBO. Using an equivalence factor of 6, the corresponding gas field sizes are 300 BCFG at the minimum, 660 BCFG at the median, and 60 TCFG at the maximum.

Coproduct Ratios and Ancillary Data

Coproduct ratios (gas/oil, NGL/oil, liquids/gas) were estimated from the *World Averages Analog Set*. Median gas/oil ratio for undiscovered fields was estimated to be 650 CFG/BO; median NGL/gas ratio was estimated to be 20 BNGL/MMCFG; and median liquids/gas ratio in undiscovered gas fields was estimated to be 20 BLIQ/MMCFG. Drilling depths for undiscovered fields were estimated from the available seismic data, and water depths within the AU were estimated from publically available bathymetric maps of Baffin Bay. Drilling depths for undiscovered oil fields ranged from a minimum of 500 m to a median of 2,000 m and to a maximum of 5,000 m. For undiscovered gas fields, drilling depths ranged from a minimum of 500 m to a median of 2,500 m and to a maximum of 9,000 m. Estimates of water depths range from a minimum of 0 m to a median of 400 m and to a maximum of 800 m.

Northeast Canada Rifted Margin AU Description

The Northeast Canada Rifted Margin AU (NCRM AU, fig. 1) encompasses all reservoirs within the extensional, rifted continental margin of northeast Canada. The AU is bounded to the west by the cratonic rocks of Baffin Island, to the north by the common boundary with the Eurekan Structures AU, to the east by the common boundary with the Baffin Bay Basin AU, and to the south with the province boundary at the northern end of the Labrador Shelf. The area of the Northeast Canada

Rifted Margin AU is about 111,000 km^2. The rifted margin of northeast Canada is narrower than the conjugate rifted margin of West Greenland (fig. 1).

Geologic Model for Assessment

The geologic model for the assessment is for petroleum generated from Cretaceous and possibly Paleogene source rocks within the deeper parts of the grabens and half grabens and from within the sag section to migrate into synrift and post-rift reservoirs (fig. 15). Most likely reservoirs are in the Upper Cretaceous post-rift section and Paleogene marginal marine to slope and fan sandstones, which are thought to be similar to the reservoirs postulated for the Northwest Greenland Rifted Margin AU. Generation is postulated to have begun in the Late Cretaceous–Paleogene in most grabens, and the petroleum would have migrated into synrift and postrift reservoirs. Given the similarity with the margin of West Greenland, the petroleum accumulations in this AU are expected to display a slight preference for oil over gas, except in the deeper grabens. This expectation is similar to the oil/gas mix for the Northwest Greenland Rifted Margin AU.

Geological Analysis of Assessment Unit Probability

Charge Probability.—Several petroleum source rocks are hypothesized in the West Greenland-East Canada Province. Source rocks might include organic-bearing Ordovician mudstones, Lower Cretaceous synrift mudstones, Upper Cretaceous marine mudstones, and Paleogene mudstones. The only evidence for petroleum in the Northeast Canada Rifted Margin AU is the oil seep offshore from Scott Inlet along Baffin Island (Balkwill and others, 1990), which has been interpreted to consist of oil with a likely Cretaceous marine source (Fowler and others, 2005). The probability of the presence of adequate source rocks in this AU was estimated to be 0.5. This value for charge probability was calibrated against charge probabilities for all other AUs defined in the Circum-Arctic Resource Appraisal program.

Rocks Probability.—Using limited drilling results from the West Greenland margin as an analog, the reservoirs and traps should be adequate for the presence of an oil or gas field of minimum size in the Northeast Canada Rifted Margin AU, so the probability is estimated to be 1.0. Given the smaller area of this AU relative to the West Greenland margin, however, there probably are fewer fields and therefore less chance of having larger sizes of fields relative to the West Greenland Rifted Margin AU. Outcrops on the southeast coast of Baffin Island might indicate the types of reservoir and seal lithologies that could be expected in grabens in this AU (Beh, 1974; Burden and Langille, 1990).

Timing and Preservation Probability.—The structures related to the extensional events in the Cretaceous and early Paleogene formed before petroleum source rocks reached the thermal windows necessary for generation. There were no subsequent tectonic events that would have been detrimental to preservation of petroleum. Timing is considered to be favorable in this AU, similar to that for the Northwest Greenland Rifted Margin AU. Additional

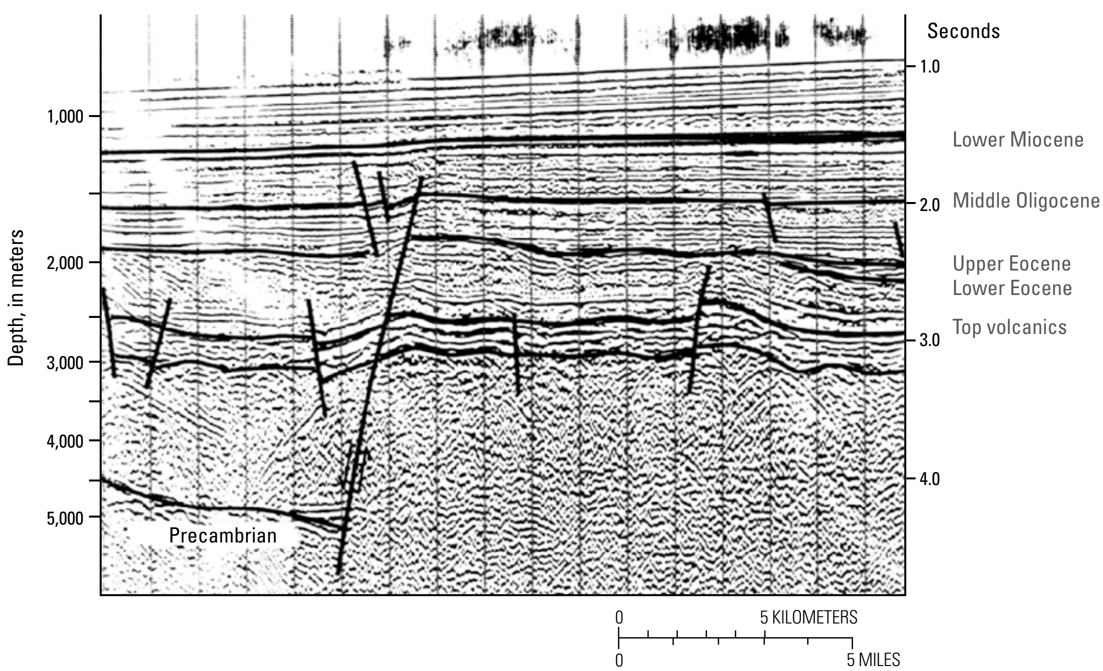

Figure 15. Seismic profile serving as geologic model for the assessment of the Northeast Canada Rifted Margin Assessment Unit (NCRM AU in fig. 1). From Klose and others (1982).

evidence for this comes from the several gas discoveries reported from the Labrador margin immediately south of this AU (Balkwill and others, 1990). From a burial-history model constructed for the Saglek Basin immediately to the south of this AU (Rolle, 1985; Issler and Beaumont, 1987), generation is interpreted have occurred in the Paleogene (fig. 16). The margin of the Baffin Bay represented by this AU has a thinner sedimentary section than the northern Labrador margin, but the Saglek Basin might be a partial analog for the petroleum system possible in the Northeast Canada Rifted Margin AU.

The geologic probability of the presence of a field of minimum size in the Northeast Canada Rifted Margin AU is the product of the three geologic probabilities discussed above, for an overall geologic probability of 0.5. This suggests that there is a 50 percent chance for the proper geologic conditions to form at least one oil or gas field of minimum size (50 MMBOE recoverable) in this AU. The assessment input data are summarized in appendix 5, and the basin evolution chart is in appendix 6. The events chart for the petroleum system elements in the Northeast Canada Rifted Margin AU is shown in figure 17.

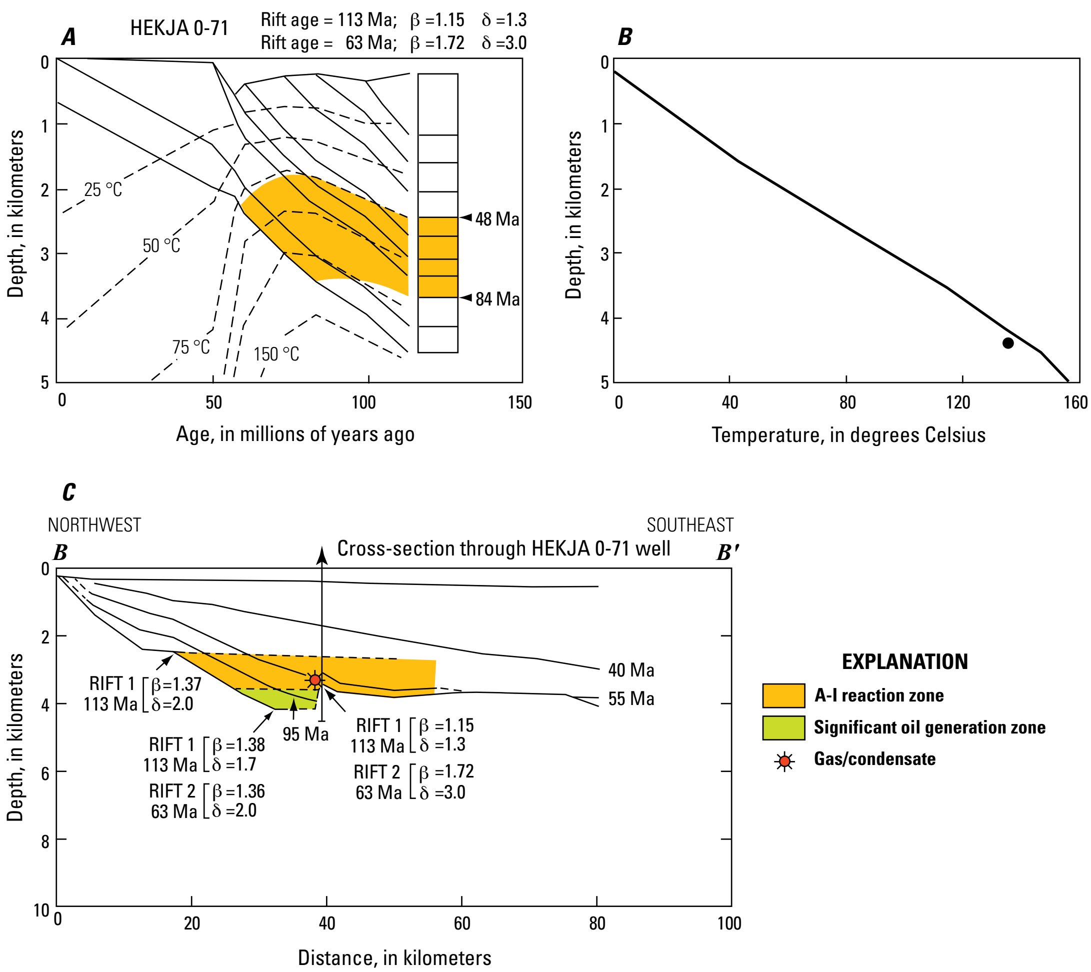

Figure 16. Burial-history diagrams for the Northeast Canada Rifted Margin Assessment Unit (NCRM AU in fig. 1). Data are from location SB in figure 1. *A*, Burial history curve; *B*, temperature model for burial history curve; *C*, cross section through Hekja well area. A-I reaction zone refers to the interval from initial generation to peak generation of oil. From Issler and Beaumont (1987).

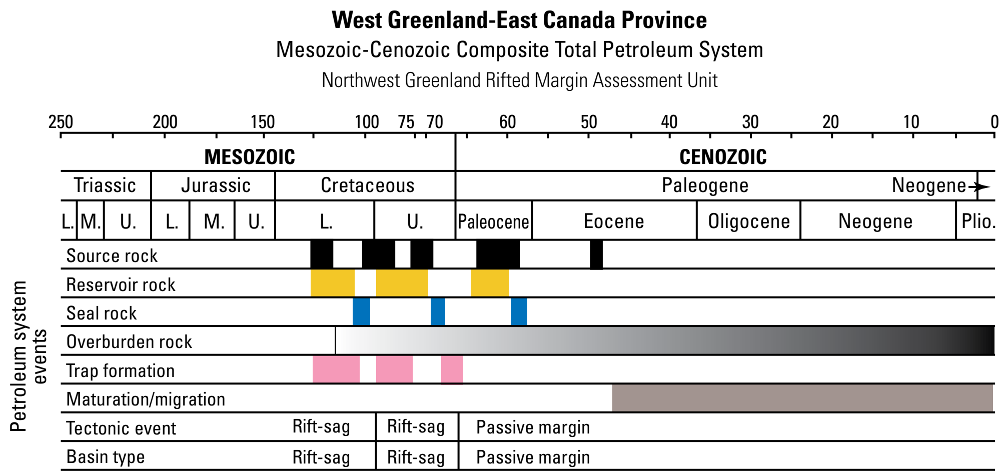

Figure 17. Total Petroleum System events chart for the Northeast Canada Rifted Margin Assessment Unit (NCRM AU in fig. 1). L., Lower; M., Middle; U., Upper; Plio., Pliocene.

Estimation of Sizes and Numbers of Undiscovered Fields

The *Architecture-Rift-Sag Analog Set* was used to estimate numbers and sizes of undiscovered oil and gas fields. The *Architecture-Rift-Sag Analog Set* and the *World Averages Analog Set* were used to estimate co-product ratios and ancillary data. These were the same analog sets used in the assessment of the Northwest Greenland Rifted Margin AU (see appendixes 3, 4).

Numbers of Undiscovered Oil and Gas Fields.—The median oil and gas field density from the *Architecture-Rift-Sag Analog Set* is 0.21 fields/1,000 km^2. This field density, combined with the AU area of 111,000 km^2, was used to calculate a median number of 20 undiscovered oil and gas fields. The maximum number of undiscovered fields was 100, which reflects a density of 0.9 fields/1,000 km^2, the same density used for the maximum number of undiscovered oil and gas fields in the West Greenland Rifted Margin AU. The distribution of numbers of undiscovered oil and gas fields is 1 at the minimum, 20 at the median, and 100 at the maximum. The oil/gas mix was interpreted to be the same as that for the conjugate West Greenland margin, and was estimated to be 60 percent at the median, with a range of uncertainty of 10 percent at the minimum to 90 percent at the maximum. Using these estimates, the distribution of undiscovered oil fields was calculated to be 1 at the minimum, 11 at the median, and 90 at the maximum. For undiscovered gas fields, the minimum was calculated to be 1 field, the median 9 fields, and 90 fields at the maximum.

Sizes of Undiscovered Oil and Gas Fields.—Sizes of undiscovered oil and gas fields were estimated using the *Architecture-Rift-Sag Analog Set*. The median oil accumulation size is estimated at 110 MMBO, as that reflects the median size of the *Architecture-Rift-Sag Analog Set*. The largest expected oil field size was estimated to be about 800–900 MMBO, so the maximum oil field size at zero probability is estimated to be 5 BBO. The distribution of undiscovered oil field sizes is 50 MMBO at the minimum, 110 MMBO at the median, and 5 BBO at the maximum. Given a scale factor of 6, the corresponding undiscovered gas field sizes were 300 BCFG at the minimum, 660 BCFG at the median, and 30 TCFG at the maximum.

Coproduct Ratios and Ancillary Data

Coproduct ratios were estimated using the coproduct ratios within the *Architecture-Rift-Sag Analog Set*. Ancillary data were derived from the *World Averages Analog Set*. Median gas/oil ratio for undiscovered fields was estimated to be 650 CFG/BO; median NGL/gas ratio was estimated to be 20 BNGL/MMCFG; and median liquids/gas ratio in undiscovered gas fields was estimated to be 20 BLIQ/MMCFG. These values are similar to those used in the West Greenland Rifted Margin AU. Estimates of drilling depths for undiscovered fields were based on the available seismic data, and water depths within the AU were estimated from publically available bathymetric maps of northern Baffin Bay and the northeast Canada margin. Drilling depths for undiscovered oil fields ranged from a minimum of 500 m to a median of 2,000 m and to a maximum of 5,000 m. For undiscovered gas fields, drilling depths ranged from a minimum of 500 m to a median of 2,500 m and to a maximum of 7,000 m. Estimates of water depth in the AU for undiscovered oil and gas fields ranged from a minimum of 0 m to a median of 500 m and to a maximum of 1,000 m.

Baffin Bay Basin AU Description

The Baffin Bay Basin AU (BBB AU, fig. 1) was defined to encompass all potential oil and gas reservoirs that could be within the 8 to 14 km–thick wedge of Paleogene and Neogene strata that occupies Baffin Bay Basin. The crust underlying Baffin Bay Basin, which formed between magnetic chrons 24 and 13, or 58 to 33 Ma (Saalmann and others, 2005), is variously thought to be oceanic crust formed in a spreading center or crust that reflects upwelling of mafic mantle material (Reid and Jackson, 1997) or extremely attenuated continental crust. The Baffin Bay Basin AU is bounded on the north by the Eurekan Structures AU, to the east and south by the Northwest Greenland Rifted Margin and Greater Ungava Fault Zone AUs, and to the west by the Northeastern Canada Rifted Margin AU. Magnetic and gravity maps greatly aided in defining these boundaries; the Baffin Bay Basin AU area is about 252,000 km^2.

Geologic Model for Assessment

The geologic model for this AU includes the southward progradation of Paleogene and Neogene clastic sediments into Baffin Bay Basin from a mostly northerly orogenic source, forming the thick clastic wedge. Sea level changes during deposition resulted in sequence boundaries, condensed sections with possible source rocks, and reservoirs in the lowstand, transgressive, and highstand systems tracts. Source rocks might include the *Azolla* horizon of Eocene age (Brinkhuis and others, 2006). Given burial by several kilometers of overburden, petroleum possibly was generated from late Paleogene or Neogene source rocks, and petroleum may have migrated into a wide range of possible reservoirs, including incised valley systems, shelf-edge deltaic systems, shoreline systems, and slope and basin-floor systems (fig. 18). A possible geologic analog might be provided by a similar clastic sequence offshore Kalimantan, Indonesia (Peters and others, 2000). Potential structural traps are related to listric faults soling on mudstones, rollovers along faults, and stratigraphic traps including slope and basin-floor fan sandstones enclosed in mudstones. Both oil and gas might have been generated from petroleum source rocks within this system possibly from condensed sections within several of the sequences.

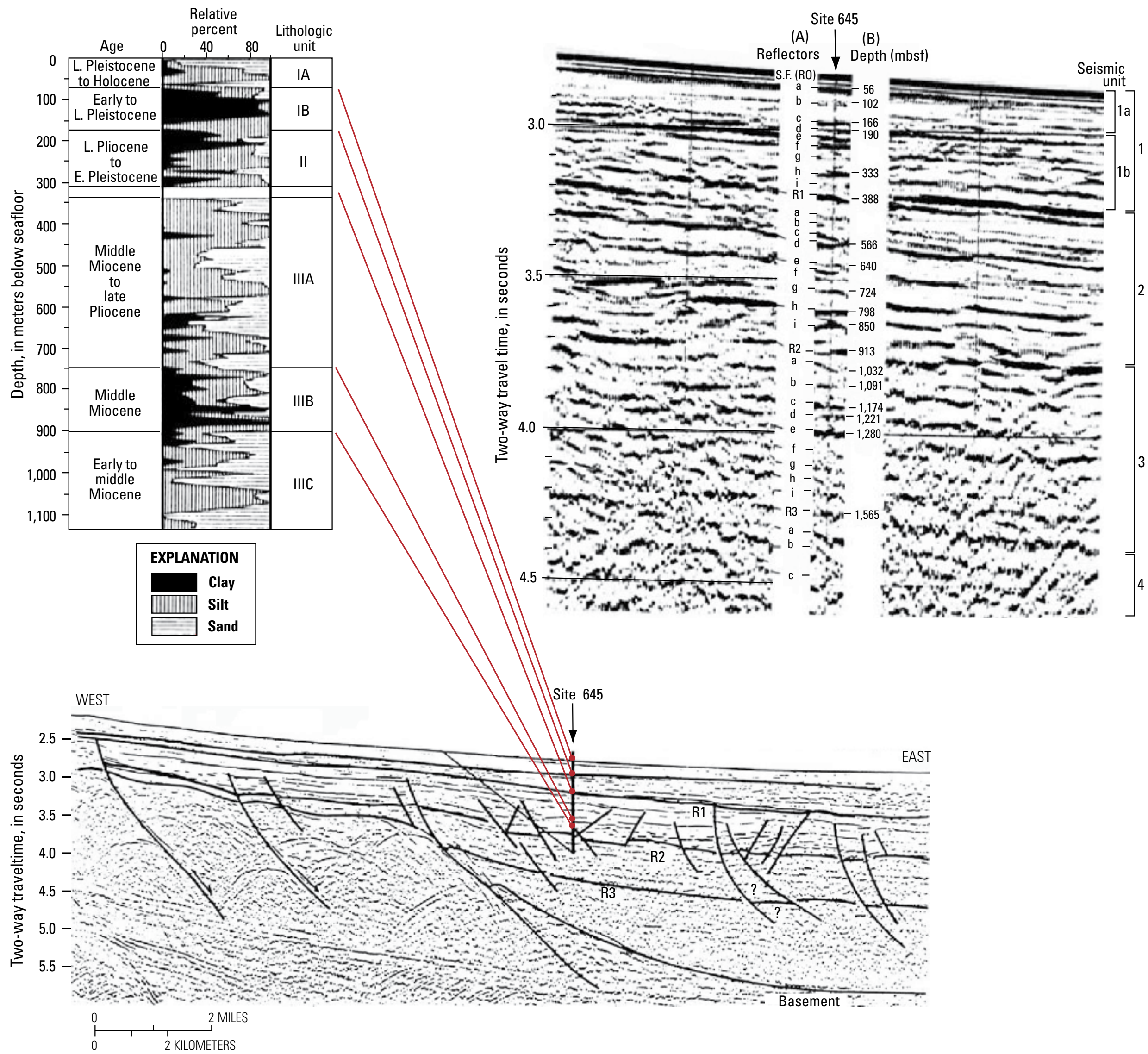

Figure 18. Seismic section and related data used as geologic model for the assessment of the Baffin Bay Basin Assessment Unit (BBB AU in fig. 1). From Arthur and others (1989). E., early; L., late; mbsf, meters below seafloor; R1, R2, and R3 are reflectors used by Arthur and others (1989) in mapping; the lithologic units (IA, IB, and so on) were also defined in the earlier study of this area (Arthur and others, 1989).

Geological Analysis of Assessment Unit Probability

Charge Probability.—The formation of Baffin Bay Basin began in late Paleogene, so the only possible petroleum source rocks possible are late Paleogene or possibly Neogene in age if buried sufficiently for thermal maturation. The organic material is postulated to be both terrestrial (type III) and marine algal oil-prone (type II). The only oil with a possible Paleogene source in the West Greenland-East Canada Province is the Maarrat oil, interpreted from a seep on Nuussuaq peninsula on the West Greenland rifted margin (Bojesen-Koefoed and others, 1999). A similar Paleogene or younger source might be present in Baffin Bay Basin. The charge probability of the Baffin Bay Basin AU was slightly lower (0.4) than the other AUs in the province because of the uncertain presence of a limited number of petroleum source rocks. This value for charge probability was calibrated against charge probability for all other AUs defined in the Circum-Arctic Resource Appraisal program.

Rocks Probability.—The geologic model suggests that the sedimentary wedge in the Baffin Bay Basin is characterized by numerous growth faults that create traps, and that base level changes resulted in coarse-grained sediment being transported across the shelves into deep water locations where the strata could potentially form reservoirs and stratigraphic traps. Seals are largely provided by intraformational mudstones and juxtaposition of reservoirs against listric faults, but uncertainty over the adequacy of such seals constitutes one of the main sources of geologic risk in this AU. Reservoir quality is interpreted to be good, however, assuming that the Eurekan orogeny produced quartzose sediment that was deposited in the sedimentary system in Baffin Bay Basin.

Timing and Preservation Probability.—The geologic model indicates that timing is favorable in the Baffin Bay Basin AU, as the reservoir rock and traps were in place prior to thermal maturation and migration, and the traps have not been subjected to deformation that would have disturbed the fluid-rock system. Petroleum generated during burial and maturation of source rocks would have migrated into traps that already existed. A simple burial-history model of the clastic sequence in Baffin Bay Basin (fig. 19) indicates that maturation of Paleogene strata would have begun in latest Paleogene time.

The overall geologic probability in this AU is the product of the three geologic probabilities, or 0.28, which suggests there is a 28 percent chance of there being at least one oil or gas accumulation of minimum size (50 MMBOE) in the AU. The assessment input data are summarized in appendix 7, and the basin evolution chart is in appendix 8. The events chart summarizing the petroleum system elements in this AU is shown in figure 20.

Estimation of Sizes and Numbers of Undiscovered Fields

The *Revised Deltas Analog Set* (D. Houseknecht, written commun., 2008) was used to estimate numbers and sizes of undiscovered oil and gas fields. This data set included deltaic analogs of the world with the salt-dominated deltas removed from the analog set, making the analog more comparable to the succession postulated to exist in Baffin Bay Basin. The *World Averages Analog Set* was used to estimate coproduct ratios and ancillary data (see appendix 7).

Numbers of Undiscovered Oil and Gas Fields.—Numbers of potential undiscovered oil and gas fields were estimated using the *Revised Deltas Analog Set*. The median density of oil and gas fields in the *Revised Deltas Analog Set* is 0.15 fields/1,000 km^2, and this density was used along with the AU area of 252,000 km^2 to calculate a median number of 40 undiscovered oil and gas fields. The maximum number of 140 undiscovered oil and gas fields was calculated using a density of 0.54 fields/1,000 km^2. The probability distribution for undiscovered oil and gas fields was 1 at the minimum, 40 at the median, and 140 at the maximum. Although subject to much uncertainty, the oil/gas mix in this AU is estimated to range from 10 percent at the minimum to 50 percent at the median and to 90 percent at the maximum. Using these values, the number of oil fields was calculated to be 1 at the minimum, 20 at the median, and 125 at the maximum. This is the same probability distribution used for undiscovered gas fields.

Sizes of Undiscovered Oil and Gas Fields.—Sizes of undiscovered oil and gas fields were estimated using the *Revised Deltas Analog Set*. The median oil accumulation size was estimated to be 120 MMBO, as that size reflected the median of the *Revised Deltas Analog Set*. The "largest expected oil field size" was estimated to be about 1 BBO based on the analog data set, leading to a maximum oil accumulation size at zero probability of 6 BBO. The distribution for undiscovered oil and gas fields is 50 MMBO at the minimum, 120 MMBO at the median, and 6 BBO at the maximum. Given a scale factor of 6, the corresponding undiscovered gas field sizes were 300 BCFG at the minimum, 720 BCFG at the median, and 36 TCFG at the maximum.

Coproduct Ratios and Ancillary Data

Coproduct ratios were estimated using the coproduct ratio summaries within the *Revised Deltas Analog Set*. Ancillary data were derived from the *World Averages Analog Set*. Median gas/oil ratio for undiscovered fields is estimated at 1,600 CFG/BO; median NGL/gas ratio was estimated at 15 BNGL/MMCFG; and median liquids/gas ratio in undiscovered gas fields was estimated

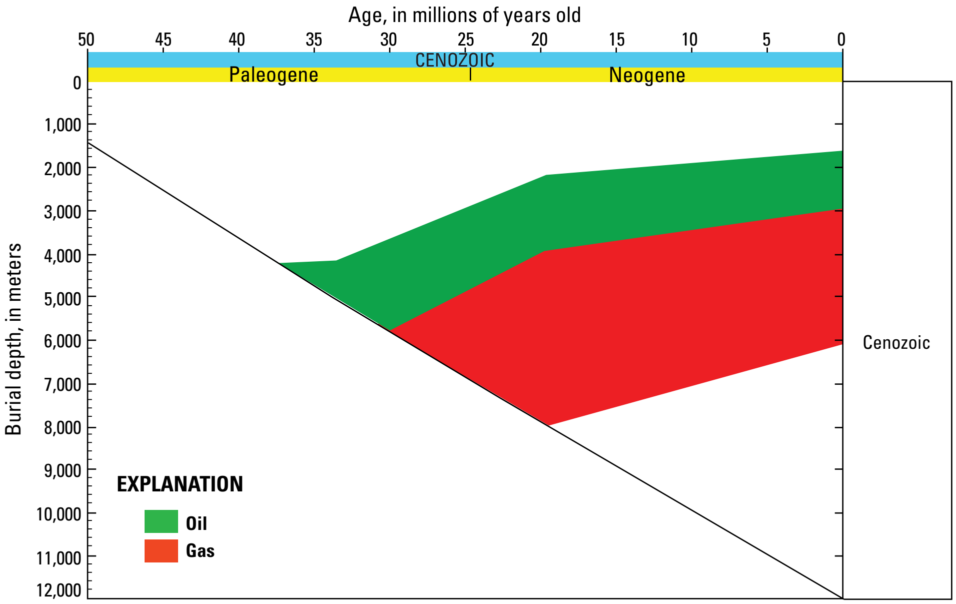

Figure 19. Burial-history diagram for the Baffin Bay Basin Assessment Unit (BBB AU in fig. 1). Location of model is at point BB in figure 1.

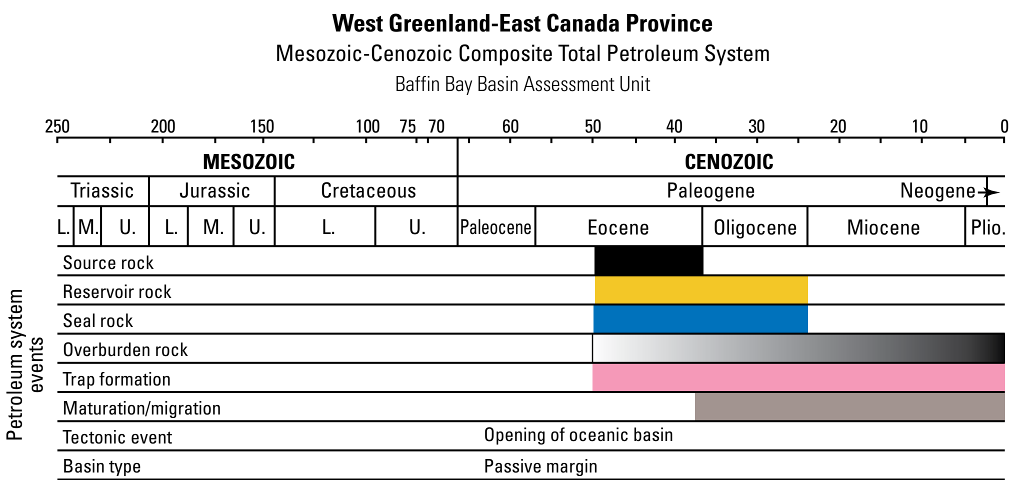

Figure 20. Total Petroleum System events chart for the Baffin Bay Basin Assessment Unit (BBB AU in fig. 1). L., Lower; M., Middle; U., Upper; Plio., Pliocene.

at 20 BLIQ/MMCFG. Drilling depths for undiscovered fields were estimated from the available seismic data, and water depths within the AU were estimated from publicly available bathymetric maps of northern Baffin Bay. Drilling depths for undiscovered oil fields ranged from a minimum of 500 m to a median of 2,000 m and to a maximum of 5,000 m. For undiscovered gas fields, drilling depths ranged from a minimum of 500 m, a median of 2,500 m, and a maximum of 9,000 m. Estimates of water depths for undiscovered oil and gas fields range from a minimum of 0 m, a median of 1,500 m, and to a maximum of 2,200 m.

Greater Ungava Fault Zone AU Description

The Greater Ungava Fault Zone Assessment Unit (GUFZ AU, fig. 1) encompasses all petroleum reservoirs in the Ungava Fault Zone, a complex fault zone with a history of extension, transtension, and transpression (Sorensen, 2006; Skaarup and others, 2006); deformation occurred as the Labrador Sea and Baffin Bay Basin opened and Greenland rotated counterclockwise into northern Canada. The Ungava Fault is part of a regional transform fault system that accommodated continental separation between Greenland and Canada and the formation of Baffin Bay Basin and Labrador Sea. The Greater Ungava Fault Zone AU is bounded to the north by the Baffin Bay Basin AU, to the west by the Northeast Canada Rifted Margin AU, to the east by the West Greenland Rifted Margin AU, and to the south by the province boundary (fig. 1). The area of the Greater Ungava Fault Zone AU is about 145,000 km^2.

Geologic Model for Assessment

The geologic model used in the assessment involves petroleum source rocks within the extensional and transtensional basins that were buried deep enough to reach thermal maturity and the windows for oil and gas generation (fig. 21). Petroleum migrated updip and vertically into synrift fluvial and deltaic sandstones and post-rift marginal marine

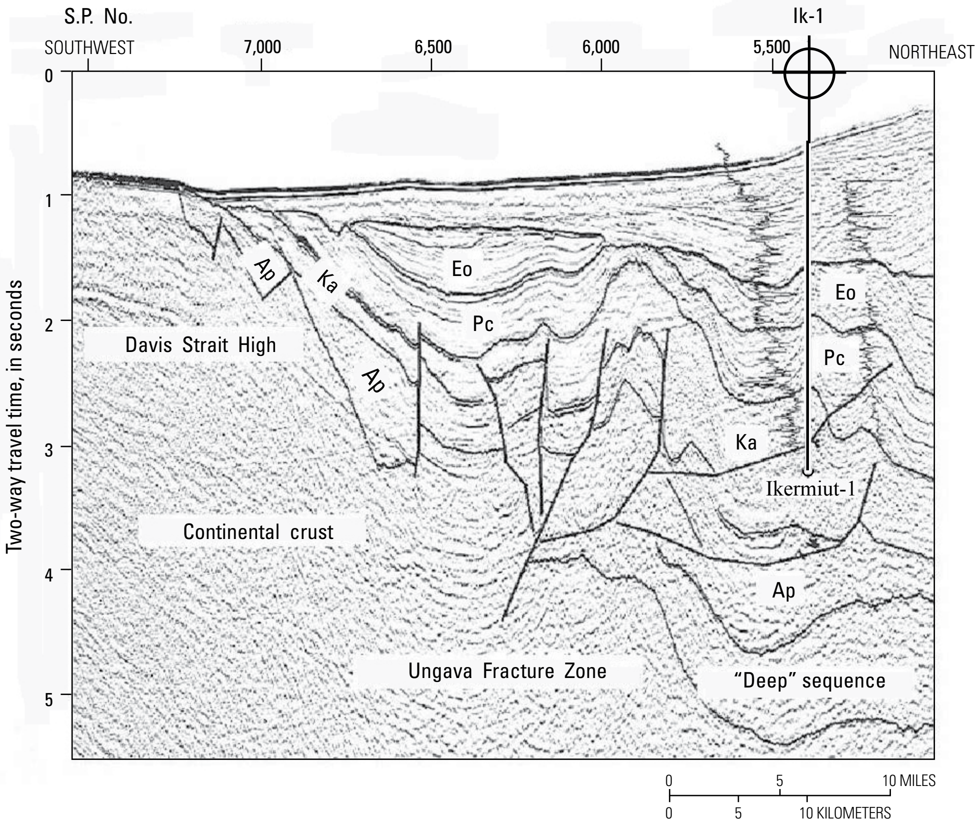

Figure 21. Seismic profile serving as geologic model for assessment of Greater Ungava Fault Zone Assessment Unit (GUFZ AU in fig. 1). From Chalmers (1991). S.P. No., shot point number from seismic survey; Ap, Appat sequence; Ka, Kangeq sequence; Pc, Paleocene sediment; Eo, Eocene sediment.

to deep marine slope and fan sandstones. Subsequent strike-slip movement along the Ungava Fault System might have remigrated previously reservoired fluids, causing a loss of petroleum from some structures. Both oil and gas are predicted to have been generated within this AU.

Geological Analysis of Assessment Unit Probability

Charge Probability.—Several petroleum source rocks are hypothesized in the West Greenland-East Canada Province. Source rocks might include organic-bearing Ordovician mudstones, Lower Cretaceous synrift mudstones, Middle and Upper Cretaceous marine mudstones, and Paleogene mudstones. Oil seeps on Nuussuaq peninsula and Disko Island, onshore West Greenland, indicate that, at least in those areas, a petroleum system is or was active. Several oils types are interpreted from these seeps, including Cretaceous oil and Paleogene oil. Two wells drilled within the Greater Ungava Fault Zone AU are classified as dry holes. Given the uncertainty about the presence of source rock to charge a field of minimum size in this AU, the charge probability was set at 0.5. This value for charge probability was calibrated against charge probabilities for all other AUs defined in the Circum-Arctic Resource Appraisal program.

Rocks Probability.—The proximity of the Greater Ungava Fault Zone AU to the Northwest Greenland Rifted Margin AU is interpreted to indicate that there is no geologic risk associated with the presence of adequate reservoir rocks, traps, and seals. The concept is that the fault zone is characterized by numerous structures that serve as potential traps, and that base level changes resulted in coarse-grained sediment being transported across the shelves into deep water where the strata form reservoirs and stratigraphic traps. Seals are largely provided by intraformational mudstones and juxtaposition of reservoirs against listric faults. Reservoir quality is expected to be good, assuming that quartzose sediment was deposited in the sedimentary system.

Timing and Preservation Probability.—The possibility of recurrent movement along the Ungava Fault Zone indicates potential risk with respect to timing and preservation of petroleum accumulations, as previously reservoired petroleum might have been remobilized and lost from the system. Two wells drilled on structure in this AU were classified as dry holes, but they might not have been optimally located on structures to be an adequate test of the presence of petroleum (Chalmers and Pulvertaft, 1992).

Burial-history modeling indicates that potential source rocks would have reached adequate thermal maturity for generation in about Late Cretaceous time (fig. 22). As some fault movement postdated the generation, fluids might have remigrated from structural traps.

The geologic probability of the presence of a field of minimum size in the Greater Ungava Fault Zone AU is the product of the three geologic probabilities discussed above, for an overall geologic probability of 0.30, which suggests that there is a 30 percent chance for the proper geologic conditions to form at least one oil or gas field of minimum size (50 MMBOE recoverable) in this AU. The assessment input data are summarized in appendix 9, and the basin evolution chart is shown in appendix 10. The events chart for the timing of petroleum system elements in this AU is shown in figure 23.

Estimation of Sizes and Numbers of Undiscovered Fields

The *Architecture-Strike-Slip Analog Set* is used to estimate numbers and sizes of undiscovered oil and gas fields, as well as for the estimation of coproduct ratios. The *World Averages Analog Set* is used to estimate ancillary data.

Numbers of Undiscovered Oil and Gas Fields.—The *Architecture-Strike-Slip Analog Set* was used to estimate undiscovered oil and gas field sizes. The median oil and gas field density in the *Architecture-Strike-Slip Analog Set* is 0.35 fields/1,000 km^2, and, along with the total AU area (145,000 km^2), the median number of undiscovered oil and gas fields in the AU was calculated to be 50. Using a maximum oil and gas field density of 1.05 yielded a maximum number of 150 oil and gas fields. The distribution for numbers of undiscovered fields is 1 at the minimum, 35 at the median, and 150 at the maximum. The uncertainty of the oil/gas mix led to the estimation that the median oil/gas mix is 50 percent, with a minimum of 10 percent and a maximum of 90 percent. Using this distribution, the number of oil fields was calculated to be 1 at the minimum, 25 at the median, and 135 at the maximum. Numbers of undiscovered gas fields have the same probability distribution.

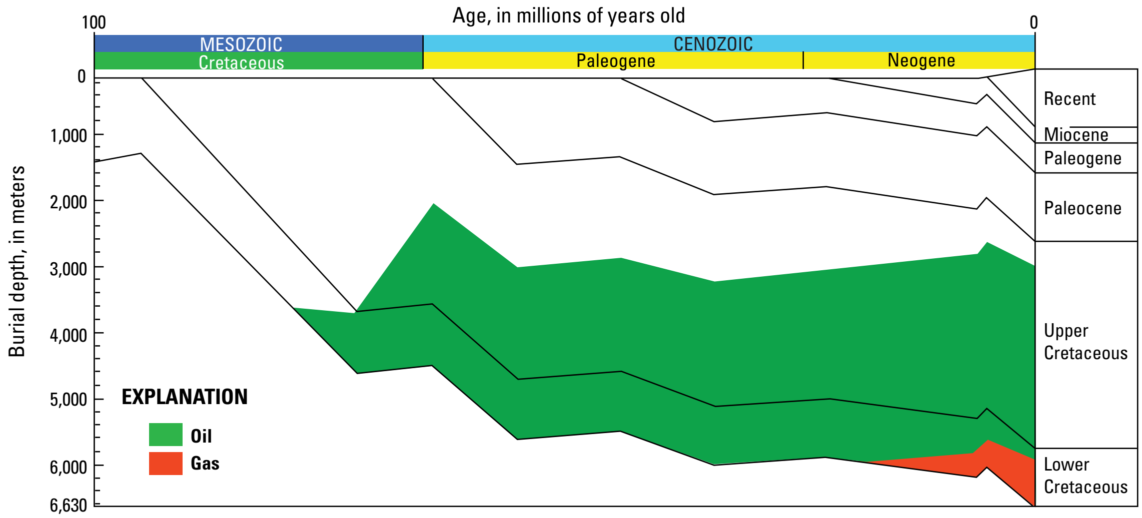

Figure 22. Burial-history diagram for the Greater Ungava Fault Zone Assessment Unit (GUFZ AU in fig. 1). Data are from Kermuit well located at point K in figure 1.

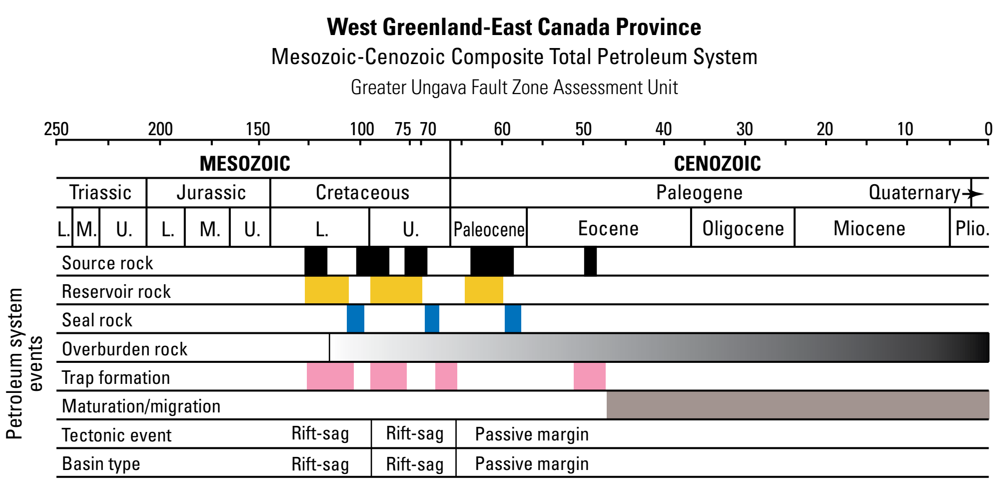

Figure 23. Total Petroleum System events chart for the Greater Ungava Fault Zone Assessment Unit (GUFZ AU in fig. 1). L., Lower; M., Middle; U., Upper; Plio., Pliocene.

Sizes of Undiscovered Oil and Gas Fields.—The *Architecture-Strike-Slip Analog Set* was used in the estimation of sizes of undiscovered oil and gas fields. The median oil field size in the *Architecture-Strike-Slip Analog Set* was about 100 MMBO; this value was adopted as the median oil field size. The largest expected oil field size was estimated to be about 1 BBO, and this leads to a maximum oil field accumulation size at zero probability of 5 BBO. Undiscovered gas accumulation sizes are scaled to the oil field sizes, and thus are 300 BCFG at the minimum, 600 BCFG at the median, and 30 TCFG at the maximum.

Coproduct Ratios and Ancillary Data

Coproduct ratios were estimated using the *Architecture-Strike-Slip Analog Set*, and the ancillary data were estimated using the *World Averages Analog Set*. Median gas/oil ratio for undiscovered fields is estimated to be 1700 CFG/BO; median NGL/gas ratio was estimated to be 16 BNGL/MMCFG; and median liquids/gas ratio in undiscovered gas fields was estimated to be 20 BLIQ/MMCFG. Drilling depths for undiscovered fields were estimated from the available seismic data, and water depths within the AU were estimated from publicly available bathymetric maps. Drilling depths for undiscovered oil fields ranged from a minimum of 500 m to a median of 2,000 m and to a maximum of 5,000 m. For undiscovered gas fields, drilling depths ranged from a minimum of 500 m to a median of 2,500 m and to a maximum of 8,000 m. Estimates of water depths for undiscovered oil and gas fields ranged from a minimum of 0 m to a median of 500 m and to a maximum of 800 m.

Assessment Results

The assessment results for the five AUs in the West Greenland-East Canada Province are summarized in table 1. The upper part of table 1 reflects the assessment of the full geographic extent of each AU (fig. 1). Three of the AUs in this study extend south of the Arctic Circle, so the resources above the Arctic Circle were allocated from the undiscovered oil and gas volumes calculated for the entire AU area (lower part of table 1).

The Eurekan Structures AU is entirely north of the Arctic Circle. The mean undiscovered oil resource is 1,133 MMBO, with an F95 of 0 MMBO and an F5 of 6,626 MMBO. Given the AU probability of 0.25 for the chance of a field of minimum size, there is a 50 percent chance that no oil resources exist in this AU (table 1). The mean volume of undiscovered nonassociated gas resource is 6,806 BCFG, with an F95 of 0 BCFG and an F5 of 39,428 BCFG. The largest expected oil field size is about 1,086 MMBO, and the largest expected gas field size is about 6, 485 BCFG. Detailed assessment results are given in appendix 11.

The Northwest Greenland Rifted Margin AU extends south of the Arctic Circle. For the total area of the AU, the mean undiscovered oil resource is 4,903 MMBO, with an F95 of 0 MMBO and an F5 of 19,465 MMBO. The mean volume of undiscovered nonassociated gas resource is 27,235 BCFG, with an F95 of 0 BCFG and an F5 of 109,082 BCFG. The largest expected oil field size in the AU is about 2,273 MMBO, and the largest expected gas field size is about 13,222 BCFG. For only that area of the AU north of the Arctic Circle, the mean undiscovered oil resource is 2,746 MMBO, with an F95 of 0 MMBO and an F5 of 10,900 MMBO. The mean volume of undiscovered nonassociated gas resource is 15,251 BCFG, with an F95 of 0 BCFG and an F5 of 61,086 BCFG. The largest expected oil field size in the AU is about 2,273 MMBO, and the largest expected gas field size is about 13,222 BCFG. Detailed assessment results are given in appendix 12.

The Northeast Canada Rifted Margin AU extends south of the Arctic Circle. For the total area of the AU, the mean undiscovered oil resource is 1,431 MMBO, with an F95 of 0 MMBO and an F5 of 5,847 MMBO. The mean volume of undiscovered nonassociated gas resource is 7,369 BCFG, with an F95 of 0 BCFG and an F5 of 31,192 BCFG. The largest expected oil field size in the AU is about 860 MMBO, and the largest expected gas field size is about 4,759 BCFG. For only that area of the AU north of the Arctic Circle, the mean undiscovered oil resource is 850 MMBO, with an F95 of 0 MMBO and an F5 of 3,470 MMBO. The mean volume of undiscovered nonassociated gas resource is 4,374 BCFG, with an F95 of 0 BCFG and an F5 of 17,577 BCFG. The largest expected oil field size in the AU is about 860 MMBO, and the largest expected gas field size is about 4,759 BCFG. Detailed assessment results are given in appendix 13.

The Baffin Bay Basin AU is entirely north of the Arctic Circle. For the AU, the mean undiscovered oil resource is 1,555 MMBO, with an F95 of 0 MMBO and an F5 of 8,470 MMBO. The mean volume of undiscovered nonassociated gas resource is 9,338 BCFG, with an F95 of 0 BCFG and an F5 of 50,598 BCFG. The largest expected oil field size is about 1,346 MMBO, and the largest expected gas field size is about 8,044 BCFG. Detailed assessment results are given in appendix 14.

The Greater Ungava Fault Zone AU extends south of the Arctic Circle. For the total AU area, the mean undiscovered oil resource is 1,675 MMBO, with an F95 of 0 MMBO and an F5 of 8,514 MMBO. The mean volume of undiscovered nonassociated gas resource is 9,892 BCFG, with an F95 of 0 BCFG and an F5 of 50,625 BCFG. The largest expected oil field size in the AU is about 1,193 MMBO, and the largest expected gas field size is about 7,164 BCFG. For only that area of the AU north of the Arctic Circle, the mean undiscovered oil resource is 991 MMBO, with an F95 of 0 MMBO and an F5 of 5,037 MMBO. The mean volume of undiscovered nonassociated gas resource is 5,852 BCFG, with an F95 of 0 BCFG and an F5 of 29,950 BCFG. The largest expected oil field size in the AU is about 1,193 MMBO, and the largest expected gas field size is about 7,164 BCFG. Detailed assessment results are given in Appendix 15.

The total mean undiscovered oil estimate for the five AUs defined in this study are 10,697 MMBO for undiscovered oil, 74,853 BCFG of undiscovered gas, and 1,655 MMB of undiscovered NGL resources (table 1).

The total mean undiscovered oil estimate for the areas of the AUs that are north of the Arctic Circle are 7,275 MMBO for undiscovered oil, 51,816 BCFG of undiscovered gas, and 1,152 MMB of undiscovered NGL resources (table 1).

The geologic probabilities for the five AUs in this study were determined based on a consideration of the geology of this province, but also on the geologic probabilities assigned to assessment units during the assessment of all Arctic basins. In this manner the probabilities were consistently applied throughout the Arctic on this assessment project.

The assessment results presented here reflect the state of geologic knowledge of the West Greenland-East Canada Province at the time of the assessment. Future drilling and evaluation of the petroleum systems within the province will greatly add to the geologic knowledge base, and will lead to a refinement of these assessment results.

Table 1. Assessment results (conventional undiscovered resources) for the West Greenland-East Canada Province.

[AU, assessment unit; BCF; billion cubic feet; MMB, million barrels; TPS, total petroleum system. Results shown are fully risked estimates. For gas fields, all liquids are included under the natural gas liquids (NGL) category. F95, 95-percent probability of at least the amount tabulated, and so on for F50 and F5. Fractiles are additive under the assumption of perfect positive ocrrelation. N/A, not applicable. Numbers do not exactly add to totals because totals were added by statistical aggregation]

Total petroleum systems and assessment units	AU probability	Field type	Largest expected oil field size	Oil (MMB)				Gas (BCF)				NGL (MMB)			
				F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
Assessment results—entire province; Mesozoic-Cenozoic composite total petroleum system															
Eurekan Structures AU	0.25	Oil	1,086	0	0	6,626	1,133	0	0	10,490	1,784	0	0	285	48
		Gas	6,485	n/a	n/a	n/a	n/a	0	0	39,428	6,806	0	0	1,055	181
Northwest Greenland Rifted Margin AU	0.5	Oil	2,273	0	464	19,465	4,903	0	280	18,728	4,548	0	6	423	102
		Gas	13,222	n/a	n/a	n/a	n/a	0	1,946	109,082	27,235	0	45	2,475	606
Northeast Canada Rifted Margin AU	0.5	Oil	860	0	0	5,847	1,431	0	0	5,591	1,325	0	0	128	30
		Gas	4,759	n/a	n/a	n/a	n/a	0	0	31,192	7,369	0	0	704	164
Baffin Bay Basin AU	0.28	Oil	1,346	0	0	8,470	1,555	0	0	16,128	2,934	0	0	244	44
		Gas	8,054	n/a	n/a	n/a	n/a	0	0	50,598	9,338	0	0	1,126	206
Greater Unavaga Fault Zone AU	0.3	Oil	1,193	0	0	8,514	1,675	0	0	18,771	3,622	0	0	329	64
		Gas	7,164	n/a	n/a	n/a	n/a	0	0	50,625	9,892	0	0	1,073	209
Total conventional resources							10,697				74,853				1,655
Assessment results—north of Arctic Circle; Mesozoic-Cenozoic composite total petroleum system															
Eurekan Structures AU	0.25	Oil	1,086	0	0	6,626	1,133	0	0	10,490	1,784	0	0	285	48
		Gas	6,485	n/a	n/a	n/a	n/a	0	0	39,428	6,806	0	0	1,055	181
Northwest Greenland Rifted Margin AU	0.5	Oil	2,273	0	260	10,900	2,746	0	157	10,488	2,547	0	4	237	57
		Gas	13,222	n/a	n/a	n/a	n/a	0	1,090	61,086	15,251	0	25	1,386	339
Northeast Canada Rifted Margin AU	0.5	Oil	860	0	0	3,470	850	0	0	3,318	787	0	0	76	18
		Gas	4,759	n/a	n/a	n/a	n/a	0	0	17,577	4,374	0	0	418	97
Baffin Bay Basin AU	0.28	Oil	1,346	0	0	8,470	1,555	0	0	16,128	2,934	0	0	244	44
		Gas	8,054	n/a	n/a	n/a	n/a	0	0	50,598	9,338	0	0	1,126	206
Greater Unavaga Fault Zone AU	0.3	Oil	1,193	0	0	5,037	991	0	0	11,105	2,143	0	0	195	38
		Gas	7,164	n/a	n/a	n/a	n/a	0	0	29,950	5,852	0	0	635	124
Total conventional resources							7,274				51,815				1,153

References

Arne, D.C., Zentilli, M., Grist, A.M., and Collins, M., 1998, Constraints on the timing of thrusting during the Eurekan orogeny, Canadian Arctic archipelago; an integrated approach to thermal history analysis: Canadian Journal of Earth Sciences, v. 35, p. 30–38.

Arthur, M.A., Srivastava, S.P., Kaminski, M., Jarrard, R., and Osler, J., 1989, Seismic stratigraphy and history of deep circulation and sediment drift development in Baffin Bay and the Labrador Sea, *in* Srivastava, S.P., Arthur, M.A., and Clement, B., 1989, eds., Proceedings of the Ocean Drilling Program, Scientific Results, v. 105, Sites 645-647, Baffin Bay and Labrador Sea, p. 957–988.

Balkwill, H.R., 1987, Labrador Basin; structural and stratigraphic style, *in* Beaumont, C., and Tankard, A.J., eds., Sedimentary basins and basin-forming mechanisms: Canadian Society of Petroleum Geologists Memoir, no. 12, p. 17–43.

Balkwill, H.R., McMillan, N.J., MacLean, B., Williams, G.L., and Srivastava, S.P., 1990, Geology of the Labrador Shelf, Baffin Bay, and Davis Strait, *in* Keen, M.J., and Williams, G.L., eds., Geology of the continental margin of eastern Canada: Geological Survey of Canada, Geology of Canada, v. 2, p. 293–348.

Barrett, P., 2003, Paleoclimatology; cooling a continent: Nature, v. 421, p. 221–223.

Beh, R.L., 1974, Evolution and geology of western Baffin Bay and Davis Strait, Canada, *in* Yorath, C.J., Parker, E.R., and Glass, D.J., eds., Canada's continental margins and offshore petroleum exploration: Canadian Society of Petroleum Geologists Memoir, no. 4, p. 453–476.

Bojesen-Koefoed, J.A., Bidstrup, T., Christiansen, F.G., Dalhoff, F., Gregersen, U., Nytoft, H.P., Nohr-Hansen, H., Pedersen, A.K., and Sonderholm, M., 2007, Petroleum seepages at Asuk, Disko, West Greenland; implications for regional petroleum exploration: Journal of Petroleum Geology, v. 30, no. 3, p. 219–236.

Bojesen-Koefoed, J.A., Nytoft, H.P., and Christiansen, F.G., 2004, Age of oils in West Greenland; was there a Mesozoic seaway between Greenland and Canada?: Geological Survey of Denmark and Greenland Bulletin, v. 4, p. 49–52.

Bojesen-Koefoed, J.A., Dam, G., Nytoft, H.P., Pedersen, G.K., and Petersen, H.I., 2001, Drowning of a nearshore peat-forming environment, Atane Formation (Cretaceous) at Asuk, West Greenland; sedimentology, organic petrography, and geochemistry: Organic Geochemistry, v. 32, p. 967–980.

Bojesen-Koefoed, J.A., Christiansen, F.G., Nytoft, H.P., and Pedersen, A.K., 1999, Oil seepage onshore West Greenland; evidence of multiple source rocks and oil mixing, *in* Fleet, A.J., and Boldy, S.A.R., eds., Petroleum geology of northwest Europe: Geological Society of London, Proceedings of the 5th Conference,, p. 305–314.

Bojesen-Koefoed, J.A., Christiansen, F.G., Nytoft, H.P., and Petersen, H.I., 1998, Petroleum source potential and the importance of marine versus terrestrial organic matter input; a comparative study of mid-Cretaceous deposits from Ellesmere Island, Northwest Territories, Canada [abs.], *in* Mukhopadhyay, P.K., Avery, M.P., Calder, J.H., and Goodarzi, F., eds., Sailing into the Millenium: Halifax, Nova Scotia, Canada, Proceedings of the Fifteenth Annual Meeting of The Society of Organic Petrology, p. 57–59.

Brent, T.A., Oakley, G.N., and Harrison, J.C., 2006, Progress towards understanding petroleum potential of the Lancaster Sound region, northern Nunavut [abs.], *in* History of convergent and passive margins in the polar realm; sedimentary and tectonic processes, transitions, and resources: Proceedings of the International Lithosphere Program Task Force Conference on Sedimentary Basins, University Laval, Quebec City, Quebec, Canada, p. 15.

Brinkhuis, H., and 22 others, 2006, Episodic fresh surface waters in the Eocene Arctic Ocean: Nature, v. 441, p. 606–609.

Burden, E.T., and Langille, A.B., 1990, Stratigraphy and sedimentology of Cretaceous and Paleocene strata in half-grabens on the southeast coast of Baffin Island, Northwest Territories: Canadian Petroleum Geologists Bulletin, v. 38, no. 2, p. 185–196.

Chalmers, J.A., 1991, New evidence on the structure of the Labrador Sea/Greenland continental margin: Journal of the Geological Society of London, v. 148, p. 899–908.

Chalmers, J.A., and Holt-Laursen, K., 1995, Labrador Sea; the extent of continental and oceanic crust and the timing of the onset of seafloor spreading: Marine and Petroleum Geology, v. 12, no. 2, p. 205–217.

Chalmers, J.A., and Pulvertaft, T.C.R., 1992, The southern West Greenland continental shelf–was petroleum exploration abandoned prematurely?, *in* Vorren, T.O., Bergsager, E., Dahl-Stamnes, O.A., Holter, E., Johansen, B., Lie, E., and Lund, T.B., eds., Arctic geology and petroleum potential: Norwegian Petroleum Society Special Publication, no. 2, p. 55–66.

Chalmers, J.A., and Pulvertaft, T.C.R., 2001, Development of the continental margins of the Labrador Sea; a review, *in* Wilson, R.C.L., Whitmarsh, R.B., Taylor, B., and Froitzheim, N., eds., Non-volcanic rifting of continental margins—A comparison of evidence from land and sea: Geological Society of London Special Publication 187, p. 77–105.

Chalmers, J.A., Pulvertaft, T.C.R., Christiansen, F.G., Larsen, H.C., Laursen, K.H., and Ottesen, T.G., 1993, The southern West Greenland continental margin—rifting history, basin development, and petroleum potential, *in* Parker, J.R., ed., Petroleum geology of northwest Europe—Proceedings of the 4th Conference: Geological Society of London, p. 915–931.

Chalmers, J.A., Pulvertaft, T.C.R., Marcussen, C., and Pedersen, A.K., 1999, New insight into the structure of the Nuussuaq Basin, central West Greenland: Marine and Petroleum Geology, v. 16, p. 197–224.

Charpentier, R.R., Klett, T.R., and Attanasi, E., 2008, Database for assessment unit-scale analogs (exclusive of the United States): U.S. Geological Survey Open-File Report 2007–1404, 61p.

Chian, D., and Louden, K.E., 1994, The continent-ocean crustal transition across the southwest Greenland margin: Journal of Geophysical Research, v. 99, no. B5, p. 9117–9135.

Chian, D., Keen, C., Reid, I., and Louden, K.E., 1995, Evolution of nonvolcanic rifted margins—new results from the conjugate margins of the Labrador Sea: Geology, v. 23, no. 7, p. 589–592.

Christiansen, F.G., and Pulvertaft, T.C.R., 1994, Petroleum-geological activities in 1993—oil source rocks the dominant theme of the season's field programme: Gronlands Geologike Underssogelse Rapport, v. 160, p. 52–56.

Christiansen, F.G., Bojrsen-Koefoed, J., Dam, G., Nytoft, H-P, Larsen, L.M., Pedersen, A.K., and Pulvertaft, T.C.R., 1996, The Marraat oil discovery on Nuussuaq, West Greenland—Evidence for a latest Cretaceous-earliest Tertiary oil prone source rock in the Labrador Sea-Melville Bay region: Bulletin of Canadian Petroleum Geology, v. 44, no. 1, p. 39–54.

Dalhoff, F., Chalmers, J.A., Gregersen, U., Nohr-Hansen, H., Rasmussen, J.A., and Sheldon, E., 2003, Mapping and facies analysis of Paleocene-Mid Eocene seismic sequences, offshore southern West Greenland: Marine and Petroleum Geology, v. 20, p. 935–986.

Dam, G., 2002, Sedimentology of magmatically and structurally controlled outburst valleys along volcanic margins—examples from the Nuussuaq Basin, West Greenland: Sedimentology, v. 49, p. 505–532.

Dam, G., and Sonderholm, M., 1994, Lowstand slope channels of the Itilli succession (Maastrichtian-Lower Paleocene), Nuussuaq, West Greenland: Sedimentary Geology, v. 94, p. 49–71.

Dam, G., Larsen, M., and Sonderholm, M., 1998a, Sedimentary response to mantle plumes; implications from Paleocene onshore successions, West and East Greenland: Geology, v. 26, p. 207–210.

Dam, G., and Sonderholm, M., 1998b, Sedimentological evolution of a fault-controlled Early Paloeocene incised valley system, Nuussuaq Basin, West Greenland, *in* Shanley, K.W., and McCabe, P.J., eds., Relative role of eustacy, climate, and tectonism in continental rocks: Society for Sedimentary Geology (SEPM) Special Publication, v. 59, p. 109–121.

Dam, G., Nohnr-Hansen, H., Pedersen, G.K., and Sonderholm, M., 2000, Sedimentary and structural evidence of a new early Campanian rift phase in the Nuussuaq Basin, West Greenland: Cretaceous Research, v. 21, p. 127–154.

DePaor, D.G., Bradley, D.C., Eisenstadt, G., and Phillips, S.M., 1989, The Arctic Eurekan orogeny—A most unusual fold-and-thrust belt: Geological Society of America Bulletin, v. 101, p. 952–967.

Fowler, M., Stasiuk, L., and Avery, M., 2005, Potential petroleum systems in the Labrador Sea and Baffin shelf areas, offshore northeastern Canada [abs.]: European Association of Organic Geochemists, Proceedings of the 22nd International Meeting on Organic Geochemistry, p. 463–464.

Frakes, L.A., Francis, J.E., and Syktus, J.I., 1992, Climate modes of the Phanerozoic—The history of the earth's climate over the past 600 million years: Cambridge, England, Cambridge University Press, 274 p.

Funck, T., Jackson, H.R., Dehler, S.A., and Reid, I.D., 2006, A refraction seismic transect from Greenland to Ellesmere Island, Canada—The crustal structure in southern Nares Strait: Polarforschung, v. 74, p. 94–112.

Funck, T., Jackson, H.R., Louden, K.E., and Klingelhofer, F., 2007, Seismic study of the transform-rifted margin in Davis Strait between Baffin Island (Canada) and Greenland—What happens when a plume meets a transform: Journal of Geophysical Research, v. 112, B04402, 22 p.

Geoffroy, L., 2001, The structure of volcanic margins; some problematics from the North Atlantic/Labrador-Baffin system: Marine and Petroleum Geology, v. 18, no. 4, p. 463–469.

Geoffroy, L., Callot, J.P., Scaillet, S., Skuce, A., Gelard, J.P., Ravilly, M., Bonin, B., Cayet, C., Perrot, K., and Lapvrier, C., 2001, Southeast Baffin volcanic margin and the North American-Greenland plate separation: Tectonics, v. 20, no. 4, p. 566–584.

Golonka, J., and Kiessling, W., 2002, Phanerozoic time scale and definition of time slices, *in* Kiessling, W., Flügel, E., and Golonka, J., eds., Phanerozoic reef patterns: Society for Sedimentary Geology (SEPM) Special Publication, v. 72, p. 11–20.

Gradstein, F.M., Ogg, J.G., and Smith, A.G., eds., 2004, A Geologic Time Scale 2004: Cambridge, England, Cambridge University Press, 589 p.

Grant, A.C., 1982, Problems with plate tectonic models for Baffin Bay–Nares Strait—evidence from the Labrador Sea, *in* Dawes, P.R., and Kerr, J.W., eds., Nares Strait and the drift of Greenland—A conflict in plate tectonics: Meddelelser om Gronland, Geosciences 8, p. 313–326.

Grant, A.C., McAlpine, K.D., and Wade, J.A., 1986, The continental margin of eastern Canada—geological framework and petroleum potential, *in* Future petroleum provinces of the world: American Association of Petroleum Geologists Memoir, no. 40, p.177–205.

Gregersen, U., and Skaarup, N., 2007, A mid-Cretaceous prograding sedimentary complex in the Sisimuit Basin, offshore West Greenland—stratigraphy and hydrocarbon potential: Marine and Petroleum Geology, v. 24, p. 15–28.

Hardenbol, J., Thierry, J., Farley, M.B., Jacquin, T., de Graciansky, P.-C., and Vail, P.R., 1998, Mesozoic and Cenozoic sequence chronostratigraphic framework for European basins, *in* de Graciansky, P.-C., Hardenbol, J., Jacquin, T., and Vail, P.R., eds., Mesozoic and Cenozoic sequence stratigraphy of European basins: Society for Sedimentary Geology (SEPM) Special Publication, v. 60, p. 3–13.

Harrison, J.C., 2005, Untested Cretaceous-Paleogene sedimentary basins of northern Baffin Bay and Nares Strait region, Arctic Canada and Greenland [abs.]: American Association of Petroleum Geologists, 2005 Convention Abstracts Volume (Calgary), p. A59

Harrison, J.C., Mayr, U., McNeil, D.H., Sweet, A.R., McIntyre, D.J., Eberle, J.J., Harington, C.R., Chalmers, J.A., Dam, G., and Nohr-Hansen, H., 1999, Correlation of Cenozoic sequences of the Canadian Arctic region and Greenland—Implications for the tectonic history of northern North America: Canadian Petroleum Geology Bulletin, v. 47, no. 3, p. 223–254.

Issler, D.R., and Beaumont, C., 1987, Thermal and subsidence history of the Labrador and West Greenland continental margins, *in* Beaumont, C., and Tankard, A.J., eds., Sedimentary basins and basin-forming mechanisms: Canadian Society of Petroleum Geologists Memoir 12, p. 45–69.

Jackson, H.R., Dickie, K., and Marillier, F., 1992, A seismic reflection study of northern Baffin Bay; implications for tectonic evolution: Canadian Journal of Earth Sciences, v. 29, p. 2353–2369.

Jackson, H.R., and Reid, I.D., 1994, Crustal thickness between the Greenland and Ellesmere Island margins determined from seismic refraction: Canadian Journal of Earth Sciences, v. 31, p. 1407–1418.

Japsen, P., and Chalmers, J.A., 2000, Neogene uplift and tectonics around the north Atlantic—overview: Global and Planetary Change, v. 24, p. 165–173.

Japsen, P., Green, P.F., and Chalmers, J.A., 2005, Separation of Paleogene and Neogene uplift on Nuussuaq, West Greenland: Journal of the Geological Society of London, v. 162, p. 299–314.

Klose, G.W., Malterre, E., McMillan, N.J., and Zinkan, C.G., 1982, Petroleum exploration offshore southern Baffin Island, northern Labrador Sea, Canada, *in* Embry, A.F., and Balkwill, H.R., eds., Arctic geology and geophysics: Canadian Society of Petroleum Geologists Memoir 8, p. 233–244.

Larsen, J.G., and Pulvertaft, T.C.R., 2000, The structure of the Cretaceous–Palaeogene sedimentary–volcanic area of Svartenhuk Halvo, central West Greenland: Geology of Greenland Survey Bulletin, no. 188, 39 p.

Lowell, J.D., 1995, Mechanics of basin inversion from worldwide examples, in Buchanan, J.G., and Buchanan, P.G., eds., Basin inversion: Geological Society of London Special Publication 88, p. 39–57.

Macauley, G., Fowler, M.G., Goodarzi, F., Snowdon, L.R., and Stasiuk, L.D., 1990, Ordovician oil shale-source rock sediments in the central and eastern Canada mainland and eastern Arctic areas and their significance to frontier exploration: Geological Survey of Canada Paper 90–14, 51 p.

MacGregor, D.S., 1995, Hydrocarbon habitat and classification of inverted rift basins, *in* Buchanan, J.G., and Buchanan, P.G., eds., Basin inversion: Geological Society of London Special Publication 88, p. 83–93.

Mathiesen, A., 2000, Basin modeling offshore southern West Greenland: Danmarks og Gronlands Geologike Undersogelse Rapport 2000/44, 33 p.

Menzies, A.W., 1982, Crustal history and basin development of Baffin Bay: Meddelelser om Gronland, v. 8, p. 295–312.

Midtgaard, H.H., 1996, Inner-shelf to lower shoreface hummocky sandstone bodies with evidence for geostrophically influenced combined flow, Lower Cretaceous, West Greenland: Journal of Sedimentary Petrology, v. 66, no. 2, p. 343–353.

Pedersen, G.V., and Pulvertaft, T.C.R., 1992, The non-marine Cretaceous of the West Greenland basin, onshore West Greenland: Cretaceous Research, v. 13, p. 263–272.

Pedersen, G.K., Andersen, L.A., Lundsteen, E.B., Petersen, H.I., Bojesen-Koefoed, J.A., and Nytoft, H.P., 2006, Depositional environments, organic maturity and petroleum potential of the Cretaceous coal-bearing Atane Formation at Qullissat, Nuussuaq Basin, West Greenland: Journal of Petroleum Geology, v. 29, no. 1, p. 3–26.

Peters, K.E., Snedden, J.W., Sulaeman, A., Sarg, J.F., and Enrico, R.J., 2000, A new geochemical-sequence stratigraphic model for the Mahakam Delta and Makassar slope, Kalimantan, Indonesia: American Association of Petroleum Geologists Bulletin, v. 84, no. 1, p. 12–44.

Preuss, T., and Dalhoff, F., 2001, Qulleq–1 (6354/4-1)—petrography of selected sidewall cores: Geological Survey of Denmark and Greenland, Danmarks og Gronlands Geologike Undersogelse Rapport 2001/33 [service report prepared for Statoil a.s.], 14 p.

Pulvertaft, T.C.R., 1997, History of petroleum exploration and summary of potential petroleum basin in Greenland: Geological Survey of Denmark and Greenland, Danmarks og Gronlands Geologiske Undersogelse Rapport 1997/62, 19 p.

Reid, I., and Jackson, H.R., 1997, Crustal structure of northern Baffin Bay; seismic refraction results and tectonic implications: Journal of Geophysical Research, v. 102, no. B1, p. 523–542.

Rice, P.D., and Shade, B.D., 1982, Reflection seismic interpretation and sea–floor spreading history of Baffin Bay, *in* Embry, A.F., and Balkwill, H.R., eds., Arctic Geology and Geophysics: Canadian Society of Petroleum Geologists Memoir 8, p. 245–265.

Riediger, C.L., Bustin, R.M., and Rouse, G.E., 1984, New evidence for the chronology of the Eurekan orogeny from south-central Ellesmere Island: Canadian Journal of Earth Sciences, v. 21, p. 1286–1295.

Roest, W.R., and Srivastava, S.P., 1989, Sea-floor spreading in the Labrador Sea—A new reconstruction: Geology, v. 17, p. 1000–1003.

Rolle, F., 1985, Late Cretaceous-Tertiary sediments offshore central West Greenland lithostratigraphy, sedimentary evolution, and petroleum potential: Canadian Journal of Earth Sciences, v. 22, p. 1001–1019.

Rowley, D.B., and Lottes, A.L., 1988, Plate-kinematic reconstructions of the North Atlantic and Arctic—Late Jurassic to present: Tectonophysics, v. 155, p. 73–120.

Saalmann, K., Tessensohn, F., Piepjohn, K., von Gosen, W., and Mayr, U., 2005, Structure of Palaeogene sediments in east Ellesmere Island—Constraints on Eurekan tectonic evolution and implications for the Nares Strait problem: Tectonophysics, v. 406, p. 81–113.

Skaarup, N., Chalmers, J.A., and White, D., 2000, An AVO study of a possible new hydrocarbon play, offshore central West Greenland: American Association of Petroleum Geologists Bulletin, v. 84, no. 2, p. 174–182.

Skaarup, N., Jackson, H.R., and Oakey, G., 2006, Margin segmentation of Baffin Bay/Davis Strait, eastern Canada, based on seismic reflection and potential field data: Marine and Petroleum Geology, v. 23, p. 127–144.

Smith, D.R., Gowan, R.J., and McComb, M., 1989, Geology and resource potential of a proposed national marine park, Lancaster Sound, Northwest Territories: Geological Survey of Canada Open-File 2022, 52 p.

Sorensen, A.B., 2006, Stratigraphy, structure and petroleum potential of the Lady Franklin and Maniitsoq Basins, offshore southern West Greenland: Petroleum Geoscience, v. 12, p. 221–234.

Ulmishek, G.F., and Klemme, H.D., 1990, Depositional controls, distribution, and effectiveness of world's petroleum source rocks: U.S. Geological Survey Bulletin B-1931, 59 p.

Whittaker, R.C., Hamann, N.E., and Pulvertaft, T.C.R., 1997, A new frontier province offshore northwest Greenland; structure, basin development, and petroleum potential of the Melville Bay area: American Association of Petroleum Geologists Bulletin, v. 81, no. 6, p. 978–998.

Wilson, R.W., Klint, K.E.S., Van Gool, J.A.M., McCaffrey, J.W., Holdsworth, R.E., and Chalmers, J.A., 2006, Faults and fractures in central West Greenland—Onshore expression of continental break-up and sea-floor spreading in the Labrador–Baffin Bay Sea, in Garde, A.A., and Kalsbeek, F., eds., Precambrian crustal evolution and Cretaceous-Paleogene faulting in West Greenland: Geological Survey of Denmark and Greenland Bulletin no. 11, p. 185–204.

Appendixes

Appendixes are available online only, and may be accessed at https://doi.org/10.3133/pp1824J.

Appendix 1. Input data for Eurekan Structures Assessment Unit.
Appendix 2. Basin evolution chart for the Eurekan Structures Assessment Unit.
Appendix 3. Input data for Northwest Greenland Rifted Margin Assessment Unit.
Appendix 4. Basin evolution chart for the Northwest Greenland Rifted Margin Assessment Unit.
Appendix 5. Input data for Northeast Canada Rifted Margin Assessment Unit.
Appendix 6. Basin evolution chart for the Northeast Canada Rifted Margin Assessment Unit.
Appendix 7. Input data for Baffin Bay Basin Assessment Unit.
Appendix 8. Basin evolution chart for the Baffin Bay Basin Assessment Unit.
Appendix 9. Input data for Greater Ungava Fault Zone Assessment Unit.
Appendix 10. Basin evolution chart for the Greater Ungava Fault Zone Assessment Unit.
Appendix 11. Detailed assessment results for Eurekan Structures Assessment Unit.
Appendix 12. Detailed assessment results for Northwest Greenland Rifted Margin Assessment Unit.
Appendix 13. Detailed assessment results for Northeast Canada Rifted Margin Assessment Unit.
Appendix 14. Detailed assessment results for Baffin Bay Basin Assessment Unit.
Appendix 15. Detailed assessment results for Greater Ungava Fault Zone Assessment Unit.

Menlo Park and Lafayette Publishing Service Centers,
California and Louisiana
Manuscript approved for publication July 14, 2017
Edited by Claire Landowski
Layout and design by James E. Banton and Cory D. Hurd

Bird and Stanley—**Geology and Assessment of Undiscovered Oil and Gas Resources of the West Greenland-East Canada Province, 2008**—Professional Paper 1824

ISSN 2330-7102 (online)
https://doi.org/10.3133/pp1824J