Chapter 41

Geology and petroleum potential of the West Greenland–East Canada Province

CHRISTOPHER J. SCHENK
US Geological Survey, MS 939, Box 25046, Denver, Colorado, USA

Abstract: The US Geological Survey (USGS) 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 programme. 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 geological basis for defining assessment units (AU) in the province, all of which are within the Mesozoic–Cenozoic Composite Petroleum System. Potential petroleum source rocks include strata of Ordovician, Lower and Upper Cretaceous, and Palaeogene ages. The five AUs defined for this study – the Eurekan Structures AU, NW Greenland Rifted Margin AU, NE Canada Rifted Margin AU, Baffin Bay AU and the Greater Ungava Fault Zone AU – encompass the entire province and were assessed for undiscovered technically recoverable resources. The mean volumes of undiscovered resources for the West Greenland–East Canada Province are $10.7 \times 10^{10}$ barrels of oil, $7.5 \times 10^{12}$ cubic feet of gas, and $1.7 \times 10^{10}$ 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 $7.3 \times 10^{10}$ barrels of oil, $52 \times 10^{12}$ cubic feet of natural gas, and $1.1 \times 10^{10}$ barrels of natural gas liquids.

Supplementary material: Supplementary Appendices 1–5 are available at http://www.geolsoc.org.uk/SUP18476.

In 2008 an appraisal of possible future additions to world conventional oil and gas resources was completed by a team of US Geological Survey scientists for the region north of the Arctic Circle. This Circum-Arctic Resource Appraisal project mapped and evaluated all of the basins of the Arctic and the present article derived from that project. The methodology used in the project and the overall results are presented in this volume in the articles by, respectively, Charpentier & Gautier (2011) and Gautier et al. (2011).

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. 41.1). 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 Eurakern age; (2) the SW boundary was drawn for this study at the northern edge of the Saglek Basin which 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 (4) 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, composite petroleum system, and assessment units extend south of the Arctic Circle (Fig. 41.1). The province boundary was drawn to include the area being assessed, and has no political significance.

Tectonic evolution

The tectonic evolution of the West Greenland–East Canada Province is complex (Fig. 41.2) and includes multiple phases of rifting, transpressional and transtensional movement along regional 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. 41.3), 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; Kloese et al. 1982; Riediger et al. 1984; Grant et al. 1986; Barkwill 1987; Rowley & Lottles 1988; DePaor et al. 1989; Roest & Srivastava 1999; Chalmers 1991; Chalmers et al. 1993; Chian & Loudon 1994; Jackson & Reid 1994; Chian et al. 1995; Chalmers et al. 1995; Holt-Laursen et al. 1995; Arne et al. 1998; Chalmers & Pulvertaft 2001; Geoffroy 2001; Geoffroy et al. 2001; Saalmann et al. 2005; Funck et al. 2006, 2007; Wilson et al. 2006). The kinematics of the Greenland and Canada cratons were strongly influenced by the migration of a mantle plume that caused thermal uplift, extension and subsequent plate movements (Harrison et al. 1999).

The area between Greenland and Canada might have been a zone of crustal weakness in the Precambrian, although there is no evidence to support this at present. Palaeozoic sedimentary rocks most likely were deposited across this area prior to rifting, as indicated by widespread outcrops (Macauley et al. 1990; Higgins et al. 1991) and seabed samples (Stouge et al. 2007), and such Palaeozoic rocks have been speculated as forming the ‘Deep Sequence’ observed on seismic sections along the West Greenland margin (Chalmers et al. 1999; Chalmers & Pulvertaft 2001). The significance of a possible Palaeozoic section in the province is that Ordovician strata might contain petroleum source and reservoir rocks (Macauley et al. 1990).

| Author | Year | Title | Journal | Volume | Pages | DOI |
|--------|------|-------|---------|--------|-------|-----|
| Grant  | 1982 |      |         |        |       |     |
| Kloese | 1982 |      |         |        |       |     |
| Riediger | 1984 |      |         |        |       |     |
| Grant  | 1986 |      |         |        |       |     |
| Barkwill | 1987 |      |         |        |       |     |
| Rowley | 1988 |      |         |        |       |     |
| DePaor | 1989 |      |         |        |       |     |
| Roest  | 1999 |      |         |        |       |     |
| Chalmers | 1991 |      |         |        |       |     |
| Chalmers | 1993 |      |         |        |       |     |
| Chian  | 1994 |      |         |        |       |     |
| Jackson | 1994 |      |         |        |       |     |
| Reid   | 1994 |      |         |        |       |     |
| Chian  | 1995 |      |         |        |       |     |
| Chalmers | 1995 |      |         |        |       |     |
| Holt-Laursen | 1995 |      |         |        |       |     |
| Arne   | 1998 |      |         |        |       |     |
| Chalmers & Pulvertaft | 2001 |      |         |        |       |     |
| Geoffroy | 2001 |      |         |        |       |     |
| Geoffroy et al. | 2001 |      |         |        |       |     |
| Saalmann et al. | 2005 |      |         |        |       |     |
| Funck et al. | 2006 |      |         |        |       |     |
| Wilson et al. | 2006 |      |         |        |       |     |
| Wilson et al. | 2007 |      |         |        |       |     |

From: SPENCER, A. M., EMBRY, A. F., GAUTHIER, D. L., STOUPAKOVA, A. V., & SHRENSEN, K. (eds) Arctic Petroleum Geology. Geological Society, London, Memoirs, 35, 627–645. 0435-4052/11/$15.00 © The Geological Society of London 2011. DOI: 10.1144/M35.41
petroleum source rocks. This sag event was followed by another phase of rifting (Fig. 41.2) in the Late Cretaceous and early Palaeogene (Dam et al. 2000; Larsen & Pulvertaft 2000), then again by thermal subsidence and passive margin sedimentation. In the Palaeogene (about Magnetic Chron 27, about 61 Ma), the first evidence of seafloor spreading in an ENE direction has been interpreted from the Labrador Sea (Chalmers & Pulvertaft 2001). The initial phase of seafloor spreading was followed by a change in spreading direction to the NNE, concomitant with the development of the Ungava transform fault and the postulated oceanic basin that floors Baffin Bay (between Magnetic Chrons 24–13, about 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 plumes that caused uplift, extension and cratonic movement in the Late Cretaceous and Palaeogene (Harrison et al. 1999; Funck et al. 2007). As Greenland progressively drifted north and NW during the Palaeogene, compressional structures formed as Greenland collided with northern Canada in what is called the Eurekan Orogeny. The northern part of the province is characterized by these late compressional structures that served to invert earlier extensional structures formed during rifting (Jackson et al. 1992).

The West Greenland–East Canada Province for this study was divided into five broadly defined structural domains related to these tectonic events: (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

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**Fig. 41.1.** Location of West Greenland–East Canada Province and five assessment units (AU; 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 (yellow lines) of the Arctic Circle. AU 1, Eurekan Structures AU; AU 2, NW Greenland Rifled Margin AU; AU 3, NE Canada Rifled Margin AU; AU 4, Baffin Bay Basin AU; AU 5, Greater Ungava Fault Zone AU. Black solid lines are locations of regional cross sections shown in Figure 41.4. Also shown are locations of cross sections in Figures 41.7, 41.9, 41.13 & 41.15.
margin sediments (Fig. 41.3); (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, pers. comm., 2008) overlain by 8–14 km of Palaeogene 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 (Sørensen 2006; Skaarup et al. 2006). These broadly defined structural domains form the basis of the West Greenland–East Canada Province.

Fig. 41.2. Main tectonic events affecting the West Greenland–East Canada Province. Modified from Saalmann et al. (2005).

Fig. 41.3. Regional cross sections of the West Greenland–East Canada Province illustrate the general structure of the province. Numbers within cross sections represent seismic velocities. Lines of section shown in Figure 41.1. From Menzies (1982).
for the five assessment units defined in this study (see later discussion). The geological 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.

Stratigraphy

Cretaceous through Neogene stratigraphy reflects the tectonic evolution of the West Greenland–East Canada Province (Fig. 41.4). Rifting in the Early Cretaceous is reflected in the lower part of the sedimentary section in which the Kitsissuit 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 such as the sediments known from the Bjarni Formation in the Canadian Labrador shelf (Balkwill et al. 1990) and Kome and Atane Formations from Nuussuaq in West Greenland (Dam et al. 2000; Larsen & Pulvertaft 2000). 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 subsidence in the Late Cretaceous led to the sag phase, with deposition more constant and widespread across the conjugate rift 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. 41.4). These sequences probably include the postulated Cenomanian–Turonian and Campanian petroleum source rocks that are considered to be the most likely potential source rocks in this province from the occurrences of oil seeps (Bojesen-Koefoed et al. 1999). 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 et al. 2003). These marginal marine sandstones have excellent reservoir properties. Deep-marine slope and fan sandstones, down depositional dip from the Fylla sandstones, are postulated to be potential reservoirs on the West Greenland margin (Dam & Sønderholm 1994) and possibly on the NE Canada margin.

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. Palaeogene strata are largely fine-grained, but include several slope and fan sandstones that also might form petroleum reservoirs (Dam 2002) and may extend well offshore (Dalhoff et al. 2003) Mudstones of the Campanian apparently constitute one of the most extensive seal-rock units in the province with up to several-hundred-metre successions in wells (Rolle 1985). The Palaeocene was a time of widespread volcanic activity in the central part of the province (Larsen & Pulvertaft 2000; Pedersen et al. 2006a), when several kilometres 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 & Chalmers 2000; Japsen et al. 2005).

Mesozoic–Cenozoic composite petroleum system

A petroleum system is defined by the extent of migration of all petroleum from a pod or pods of thermally mature source rock. With several wells drilled in the 940,000 km² area of the West Greenland–East Canada Province, the definition of petroleum systems in this province is based on limited information (Fig. 41.5). Several possible petroleum source rocks have been suggested or interpreted from geochemical data and geological arguments, including Palaeogene, Lower and Upper Cretaceous and Ordovician rocks.

Oil seeps described from onshore west Greenland and offshore east Canada provide excellent evidence that, at least in those areas, a petroleum system is or was active (Christiansen & Pulvertaft 1994; Christiansen et al. 1996; Bojesen-Koefoed et al. 1999). An oil seep offshore from Scott Inlet in northeastern Canada waters (Maclean et al. 1981; Balkwill et al. 1990) has been interpreted as most likely having an Upper Cretaceous marine shale source (Fowler et al. 2005), and the oil is interpreted to be one possibly derived from Upper Cretaceous shales of the Kanguk Formation similar to rocks exposed on Ellesmere Island.

Oil seeps and oil-stained rocks that are widely distributed in Albian to Palaeogene 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 et al. 1998, 1999, 2004, 2007; Pedersen et al. 2006b). The first oil, called the Marraat oil, is considered to be the best characterized of the five oils, and is a typical ‘high wax’ oil sourced from a deltaic mudstone with high.

Fig. 41.5. Petroleum system map for the West Greenland–East Canada Province. After Bojesen-Koefoed et al. (1999).
terrigenous organic matter content. Extracts from thermally immature Paleocene mudstones from Nuussuaq are considered to correlate with the oil from the oil seeps. The second oil, the Kuagangnuquq oil, is found on Disko Island, and is ‘high wax’ oil with source interpreted to have high 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 carbonate mudstones of the Alban–Cenomanian Atane Formation that have been intensively studied in outcrop (Pedersen et al. 2006b). The third oil recognized in the seeps, the Iulli oil, is low-wax oil typical of oil from a marine mudstone. No source rocks of this type are known from outcrop, but the inference was made that the marine source rock might have been shales similar to the Cenomanian–Turonian Kanguk Formation such as those rocks exposed on Ellesmere Island (Bojesen-Koefoed et al. 1998). The remaining two oils were interpreted to have local sources. Mixing of these several oils was also reported from analyses of the seeps (Bojesen-Koefoed et al. 1999).

Other potential source rocks have been postulated from the province. Synrift lacustrine and/or marine petroleum source rocks might have been deposited in Early Cretaceous syn-rift sections. The oil might have reached thermal maturity and sourced reservoirs in the synrift section (Gregersen et al. 2007). However, as yet there is no evidence of Early Cretaceous source rocks in this province due to a lack of drilling. The suggestion has also been made that rifting might 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, but this remains speculative. There is also the possibility that Ordovician organic-bearing shales might have been a source for petroleum in this province based on a reported drudge sample of a potential Ordovician source rock from the southeastern part of the province (GEUS, pers. comm., 2007) and an additional sample from an outcrop in SW Greenland (Fig. 41.5). Cretaceous rocks, including what may be potential source rocks, have been interpreted as subcropping in Baffin Bay (Planke et al. 2009). 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 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. 41.1). The concept is that 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 (AU 1) was defined to encompass all structures in the northern part of the province that were affected by Palaeogene compression and inversion as Greenland rotated counterclockwise and progressively collided with Canada. The NW Greenland Rifted Margin Assessment Unit (AU 2) includes all extensional structures developed along the West Greenland continental margin during Cretaceous and early Palaeogene rifting. Likewise, the Northeastern Canada Rifted Margin Assessment Unit (AU 3) was defined to include extensional structures of the same age along the conjugate margin of northeastern Canada. The Baffin Bay Basin AU (AU 4) includes potential reservoirs within the thick sedimentary section developed in Baffin Bay during the late Palaeogene and Neogene. The Greater Ungava Fault Zone AU (AU 5) encompasses structural traps developed within the Ungava transform fault zone. The northeastern part of the Greater Ungava Fault Zone AU was difficult to differentiate from the central part of the NW Greenland Rifted Margin AU, and part of this former AU alternatively could have been placed in the latter AU. The definition of AU boundaries was based partly on a series of gravity and magnetic maps (P. Brown, pers. comm., 2008).

Eurekan Structures AU description

The Eurekan Structures AU (AU 1, Fig. 41.1) 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 SW spays of the Nares Fault system in the Palaeogene. Finally, these structures were affected by compression associated with the Eurekan Orogeny (Jackson et al. 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 effects on extensional structures, and this area is only approximately known. Total area of the Eurekan Structures AU is about 146 000 km², and includes most of Kane Basin, Kap York Basin, Glacier Basin, North Water Basin, Lady Ann Basin, Lancaster Sound Basin and others (Harrison 2005).

Geological model for assessment

The geological model for assessment of the Eurekan Structures AU largely involves Early Cretaceous and Late Cretaceous to Palaeogene grabens and half-grabens filled with a typical synrift facies, including potential source and reservoir rocks (Fig. 41.6). Upper Cretaceous strata might include source rocks of Cenomanian–Turonian and Campanian ages. Oil and gas generated from possible Early and Late Cretaceous source rocks migrated updip into structural and stratigraphic traps. Eurekan compression in the late Palaeogene 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). Assessment of geological risk was 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 et al. 1999, 2004, 2007). Postulated source rocks include organic-bearing Ordovician mudstones (Maucely et al. 1990), Lower Cretaceous synrift mudstones, Upper Cretaceous marine mudstones and Palaeogene mudstones and possibly coals. Oil seeps on Nuussuaq Peninsula and Disko Island of onshore West Greenland provide excellent evidence of petroleum generation from organic-bearing rocks, and the seeps include what are interpreted to be Cretaceous oils and Palaeogene oil (Bojesen-Koefoed et al. 1999). At present there are no oil and gas discoveries or wells with shows in this AU. Outcrops of Upper Cretaceous rocks exposed on Ellesmere Island represent analogues to potential source rocks in this AU (Bojesen-Koefoed et al. 1998). The concept is that these rocks extended across this continental margin. The charge probability was estimated to be 0.5 for a field of minimum size (50 million barrels 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 programme.

Rocks probability. Structural traps have been described from this AU (Brent et al. 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. A significant geological risk in this AU is to what degree the compressive phase of deformation related to the Eurekan Orogeny in the Palaeogene affected petroleum that might have resided in structures in this AU. Compression might have resulted in the inversion of preexisting extensional structures, thereby possibly causing re-migration of oil and gas updip from earlier-formed traps. 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 was estimated at 0.5 that a field of minimum size is present within the AU.

The geological probability of the presence of a field of minimum size in the Eurekan Structures AU is the product of the three geological probabilities discussed above, for an overall geological probability of 0.25 (the AU probability in Table 41.1). This suggests that there is a 25% chance for the proper geological 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 Supplementary Appendix 1. The results chart summarizing the elements of the petroleum system is shown in Figure 41.7.

Estimation of sizes and numbers of undiscovered fields

The Structural Setting–Compressional Analogue Set of the US Geological Survey analogue database (Charpentier et al. 2008) was used as the primary geological analogue 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 Analogue Set was used as a guide for the estimation of co-product ratios and ancillary data.

The median density of oil and gas fields from the Structural Setting–Compressional Analogue Set is 0.24 fields/1000 km². Given that field density and the total Eurekan Structures AU area of 146,000 km², 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/1000 km², 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 due to a lack of data. Limited burial history modelling 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%, and the estimated range is from 10% at the minimum to 90% at the maximum. Given this distribution, the number of undiscovered oil accumulations 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 sizes and numbers of prospects described from this AU (Brent et al. 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 Analogue Set. The median oil field size in the Structural Setting—Compressional Analogue 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’ was estimated to be about 1 billion barrels oil (BBO) based on the median size of the largest field sizes given in the Structural Setting—Compressional Analogue Set. Adopting 1 BBO for the ‘largest expected oil field size’ led to a calculated maximum oil field size 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. Using 1 MMBO equals 6 BCFG (billion cubic feet of gas) as an approximate equivalency between oil and gas field volumes, the sizes of undiscovered gas fields were calculated by multiplying the undiscovered oil field sizes by 6, leading to a minimum of 300 BCFG, a median of 720 BCFG, and a maximum of 30 BCFG for undiscovered gas field sizes.

Co-product ratios and ancillary data

Estimates of co-product 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 Analogue Set in the world analogue database (Supplementary Appendix 1). Using this analogue set, the median gas–oil ratio was 1000 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...
### Table 41.1. West Greenland-East Canada Province assessment results

| Total petroleum systems (TPS) and assessment units (AU) | AU probability | Field type | Largest expected oil field size | Oil (MMBO) | Total undiscovered resources | NGL (Million BNGL) |
|--------------------------------------------------------|----------------|------------|---------------------------------|------------|-------------------------------|-----------------|
|                                                        |                |            |                                 | F95 | F50 | F5 | Mean | F95 | F50 | F5 | Mean | F95 | F50 | F5 | Mean |
| Assessment results – entire province                    |                |            |                                 |        |     |     |       |        |     |     |     |        |     |     |     |        |
| Mesozoic–Cenozoic Composite TPS                         |                |            |                                 |        |     |     |       |        |     |     |     |        |     |     |     |        |
| Eurekan Structures AU                                   | 0.25           | Oil        | 1086                            | 0 0 6626 | 1133 | 0 0 10 490 1784 | 0 0 285 48  |
|                                                        |                | Gas        | 6485                           | 0 0 39 428 | 6806 | 0 0 10 55 181 | 0 0 1055 181 |
| NW Greenland Rifted Margin AU                           | 0.50           | Oil        | 2273                            | 0 0 464 | 19 465 | 4903 | 0 0 280 18 728 | 4548 | 0 0 6 423 | 102 |
|                                                        |                | Gas        | 13 222                          | 0 0 1946 | 109 082 | 27 235 | 0 0 45 247 | 53 | 0 0 2475 | 606 |
| NE Canada Rifted Margin AU                              | 0.50           | Oil        | 860                             | 0 0 5847 | 1431 | 0 0 5591 1325 | 0 0 128 30  |
|                                                        |                | Gas        | 4759                           | 0 0 31 192 | 7369 | 0 0 70 4 | 164  |
| Baffin Bay Basin AU                                     | 0.28           | Oil        | 1346                            | 0 0 8470 | 1555 | 0 0 16 128 | 2934 | 0 0 244 | 44  |
|                                                        |                | Gas        | 8054                           | 0 0 50 598 | 9338 | 0 0 11 26 | 206  |
| Greater Ungava Fault Zone AU                            | 0.30           | Oil        | 1193                            | 0 0 8514 | 1675 | 0 0 18 771 | 3622 | 0 0 329 | 64  |
|                                                        |                | Gas        | 7164                           | 0 0 50 625 | 9892 | 0 0 10 73 | 209  |
| Total conventional resources                             |                |            |                                 | 10 697 | 74 853 | 1655 | 10 697 | 74 853 | 1655 |
| Assessment results – north of Arctic Circle             |                |            |                                 |        |     |     |       |        |     |     |     |        |     |     |     |        |
| Mesozoic–Cenozoic Composite TPS                         |                |            |                                 |        |     |     |       |        |     |     |     |        |     |     |     |        |
| Eurekan Structures AU                                   | 0.25           | Oil        | 1086                            | 0 0 6626 | 1133 | 0 0 10 490 1784 | 0 0 285 48  |
|                                                        |                | Gas        | 6485                           | 0 0 39 428 | 6806 | 0 0 10 55 181 | 0 0 1055 181 |
| NW Greenland Rifted Margin AU                           | 0.50           | Oil        | 2273                            | 0 0 464 | 19 465 | 4903 | 0 0 280 18 728 | 4548 | 0 0 6 423 | 102 |
|                                                        |                | Gas        | 13 222                          | 0 0 1946 | 109 082 | 27 235 | 0 0 45 247 | 53 | 0 0 2475 | 606 |
| NE Canada Rifted Margin AU                              | 0.50           | Oil        | 860                             | 0 0 5847 | 1431 | 0 0 5591 1325 | 0 0 128 30  |
|                                                        |                | Gas        | 4759                           | 0 0 31 192 | 7369 | 0 0 70 4 | 164  |
| Baffin Bay Basin AU                                     | 0.28           | Oil        | 1346                            | 0 0 8470 | 1555 | 0 0 16 128 | 2934 | 0 0 244 | 44  |
|                                                        |                | Gas        | 8054                           | 0 0 50 598 | 9338 | 0 0 11 26 | 206  |
| Greater Ungava Fault Zone AU                            | 0.30           | Oil        | 1193                            | 0 0 8514 | 1675 | 0 0 18 771 | 3622 | 0 0 329 | 64  |
|                                                        |                | Gas        | 7164                           | 0 0 50 625 | 9892 | 0 0 10 73 | 209  |
| Total conventional resources                             |                |            |                                 | 7274 | 51 815 | 1153 | 7274 | 51 815 | 1153 |

MMBO, million barrels of oil; BCFG, billion cubic feet of gas; BNGL, barrels of natural gas liquids. Results shown are fully risked estimates. For gas accumulations, all liquids are included as NGL (natural gas liquids). Undiscovered gas resources are the sum of nonassociated and associated gas. F95 represents a 95% chance of at least the amount tabulated; other fractiles are defined similarly. AU probability is the chance of at least one accumulation of minimum size within the AU. TPS, total petroleum system; AU, assessment unit. Grey shading indicates not applicable; oil field sizes in MMBO; gas field sizes in SCFG.
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 2000 m, and a maximum of 5000 m. For undiscovered gas fields, drilling depths ranged from a minimum of 500 m, to a median of 2500 m, and a maximum of 7000 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 1000 m.

NW Greenland Rifted Margin AU description

The NW Greenland Rifted Margin AU (AU 2, Fig. 41.1) 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 SW Greenland margin (Fig. 41.1). The AU includes the Melville Bay Graben (Whittaker et al. 1997). The area of the West Greenland Rifted Margin AU is approximately 286 000 km². The AU is divided into two portions by the northern end of the Greater Ungava Fault Zone AU. The boundary with the Greater Ungava Fault Zone AU is not well established as the extent of strike-slip deformation that extends laterally and to the NE from the Greater Ungava Fault Zone is uncertain.

Geological model for assessment

The geological model for the assessment of the NW Greenland Rifted Margin AU includes the formation of extensional structures in the Early Cretaceous and in the Late Cretaceous–Palaeogene as Greenland progressively rifted from eastern Canada (Fig. 41.8). 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 Palaeogene age (Skaarup et al. 2000, 2006; Dalhoff et al. 2003; Gregersen & Skaarup 2007; Gregersen & Bidstrup 2008). Most likely source rocks include Cenomanian–Turonian, Campanian and Palaeogene organic-bearing strata. Petroleum generated from the maturation of source rocks during burial 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 geological 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 Palaeogene 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 Palaeogene oil (Bojesen-Koefoed et al. 1999). Wells drilled within this AU were classified as dry holes or as having shows (Chalmers & 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.

Fig. 41.9. Map of present-day thermal maturities of Cretaceous successions in a series of grabens/basins along the central part of the NW Greenland margin. From Gregersen et al. (2007).
generated in the deeper thermally mature grabens could have migrated updip into synrift and post-rift reservoirs, with no further tectonic deformation affecting the preservation of petroleum in existing traps. Thermal maturity maps by GEUS of several basins in this extensional margin using seismic mapping illustrates the heterogeneous maturation of potential source rocks, as the pods of mature source rocks are within the rift margin (Fig. 41.9).

The geological probability of the presence of a field of minimum size in the NW Greenland Rifted Margin AU is the product of the three geological probabilities discussed above, for an overall geological probability of 0.5 (Table 41.1). This suggests that there is a 50% chance for the proper geological 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 Supplementary Appendix 2. The events chart summarizing the petroleum system elements in this AU is presented in Figure 41.10.

Estimation of sizes and numbers of undiscovered fields

The assessment of the NW Greenland Rifted Margin AU utilized the Architecture–Rift–Sag Analogue Set from the analogue database, as this set of analogues reflects the sizes and numbers of traps associated with rift–sag systems. The Architecture–Rift–Sag Analogue Set was used to estimate numbers and sizes of undiscovered oil and gas accumulations. The co-product ratios and ancillary data were based on data from the World Averages Analogue Set.

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 Analogue Set. The median density of oil and gas fields from the Architecture–Rift–Sag Analogue Set is 0.21 fields/1000 km². Combining this with the NW Greenland Rifted Margin AU area of 286 000 km², 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/1000 km², 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. Modelling indicates that petroleum in this AU comprises more oil than gas (Mathiesen 2000), and the mode of the oil–gas mix was estimated at 60%, with a minimum of 10% and a maximum of 90% reflecting the inherent uncertainties. The distribution of oil–gas mix was used to estimate one oil field at the minimum, 30 oil fields at the median and 225 oil fields at the maximum; and one 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 Analogue Set. Median undiscovered oil field size was estimated to be 110 MMBO based on the size distribution in the analogue 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 (Dahlhoff et al. 2003). Given a ‘largest expected oil field size’ of about 2 BBO, the maximum oil field size 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.

Co-product ratios and ancillary data

Co-product ratios (gas–oil, NGL–oil, liquids–gas) were estimated from the World Averages Analogue 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, a median of 2000 m and a maximum of 5000 m. For undiscovered gas fields, drilling depths ranged from a minimum of 500 m, a median of 2500 m and a maximum of 9000 m. Estimates of water depths range from a minimum of 0 m to a median of 400 m and a maximum of 1500 m.

NE Canada Rifted Margin AU description

The NE Canada Rifted Margin AU (AU 3, Fig. 41.1) encompasses all reservoirs within the extensional, rifted continental margin of NE 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 NE Canada Rifted Margin AU is about 111 000 km². The rifted margin of NE Canada is narrower than the conjugate rifted margin of West Greenland (Fig. 41.1).

Geological model for assessment

The geological model for the assessment is for petroleum generated from Cretaceous and possibly Palaeogene 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, similar to the West Greenland conjugate margin (Fig. 41.8). Most likely reservoirs are in the Upper Cretaceous post-rift section and Palaeogene marginal marine to slope and fan sandstones, which are thought to be similar to the reservoirs postulated for the NW Greenland Rifted Margin AU. Generation is postulated to have begun in the Late Cretaceous–Palaeogene in most grabens, and the petroleum would have migrated into synrift and post-rift reservoirs (Fig. 41.8). 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 NW 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 Palaeogene mudstones. The only evidence for petroleum in this AU is the oil seep offshore from Scott Inlet along Baffin Island (Maclean et al. 1981; Balkwill et al. 1990) which has been interpreted to consist of oil with a likely Cretaceous marine source (Fowler et al. 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 programme.

Rocks probability. Using limited drilling results from the West Greenland margin as an analogue, the reservoirs and traps should be adequate for the presence of an oil or gas field of minimum size in this 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 would be fewer fields and therefore less chance of having larger sizes of fields relative to the West Greenland Rifted Margin AU. Outcrops on the SE 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 & Langille 1990).

Timing and preservation probability. Structures related to the extensional events in the Cretaceous and early Palaeogene formed before petroleum source rocks reached the thermal windows necessary for generation. No subsequent tectonic events therefore would have been detrimental to preservation of petroleum. Timing is considered to be favourable in this AU, similar to the NW Greenland Rifted Margin AU. Additional evidence for this comes from the several gas discoveries reported from the Labrador margin immediately south of this AU (Balkwill et al. 1990). From a burial-history model constructed for the Saglek Basin immediately to the south of this AU (Rolle 1985; Issler & Beaumont 1987), generation is interpreted to have begun in the Palaeogene. The margin of NE Canada represented by this AU has a thinner sedimentary section than the northern Labrador margin, but the Saglek Basin might be a partial analogue for the petroleum system possible in the NE Canada Rifted Margin AU (Jauer & Budkewitsch 2010).

The geological probability of the presence of a field of minimum size in the NE Canada Rifted Margin AU is the product of the three geological probabilities discussed above, for an overall geological probability of 0.5. This suggests that there is a 50% chance for the proper geological 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 Supplementary Appendix 3. The events chart for the petroleum system elements in the NE Canada Rifted Margin AU is shown in Figure 41.11.

Estimation of sizes and numbers of undiscovered fields

The Architecture–Rift–Sag Analogue Set was used to estimate numbers and sizes of undiscovered oil and gas fields. The Architecture–Rift–Sag Analogue Set and the World Averages Analogue Set were used to estimate co-product ratios and ancillary data. These were the same analogue sets as used in the assessment of the NW Greenland Rifted Margin AU.

Numbers of undiscovered oil and gas fields. The median oil and gas field density from the Architecture–Rift Sag Analogue Set is 0.21 fields/1000 km². This field density, combined with the AU area of 111 000 km², 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/1000 km², 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 one 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% at the median, with a range of uncertainty of 10% at the minimum to 90% at the maximum. Using these estimates, the distribution of undiscovered oil fields was calculated to be one at the minimum, 11 at the median and 90 at the maximum. For undiscovered gas fields, the minimum was calculated to be one field, the median nine 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 Analogue Set. The median oil accumulation size is estimated at 110 MMBO, as that reflects the median size of the Architecture–Rift–Sag Analogue Set. The ‘largest expected oil field size’
was estimated to be about 800–900 MMBO, so the maximum oil field size 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 equivalency 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.

Co-product ratios and ancillary data
Co-product ratios were estimated using the co-product ratios within the Architecture–Rift Sag Analogue Set. Ancillary data were derived from the World Averages Analogue Set. Median gas–oil ratio for undiscovered fields was estimated to be 650 SCFG/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 NE Canada margin. Drilling depths for undiscovered oil fields were a minimum of 500 m, a median of 2000 m and a maximum of 5000 m. For undiscovered gas fields, drilling depths were a minimum of 500 m, a median of 2500 m and a maximum of 7000 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, to a maximum of 1500 m.

Baffin Bay Basin AU description
The Baffin Bay Basin AU (AU 4, Fig. 41.1) was defined to encompass all potential oil and gas reservoirs that could be within the 8–14 km-thick wedge of Palaeogene and Neogene strata that occupies Baffin Bay Basin. The crust underlying Baffin Bay Basin, which formed during Magnetic isochron 24–13, or 58–33 Ma (Saalmann et al. 2005), is variously thought to be oceanic crust formed in a spreading centre, crust that reflects upwelling of mafic mantle material (Reid & 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 partly by the NW 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 km².

Geological model for assessment
The geological model for this AU includes the southward progradation of Palaeogene and Neogene clastic sediments into Baffin Bay Basin from a mostly northerly orogenic source, forming a 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 et al. 2006). Given burial by several kilometres of overburden, petroleum possibly was generated from late Palaeogene or Neogene source rocks, and petroleum migrated into a wide range of possible reservoirs, including incised valley systems, shelf-edge deltaic systems, shoreline systems, and slope and basin-floor systems some of which may be equivalent to the Neogene sands drilled in the ODP-645 well (Fig. 41.12). A possible geological analogue might be provided by a similar clastic sequence offshore Kalimantan, Indonesia (Peters et al. 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 organic-rich condensed sections within several of the sequences.

Geological analysis of assessment unit probability

Charge probability. The formation of Baffin Bay Basin began in late Palaeogene, so the only possible petroleum source rocks are late Palaeogene 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 Palaeogene 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 et al. 1999). A similar Palaeogene or younger source might be present in Baffin Bay Basin. The charge probability was slightly lower (0.4) than the other AUs in this province because of the uncertain presence of a limited number of petroleum source rocks and thermal maturation. This value for charge probability was calibrated against charge probability for all other AUs defined in the Circum-Arctic Resource Appraisal programme.

Rocks probability. The geological model suggests that the sedimentary wedge in this 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 deepwater 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 geological risk in this AU. Reservoir quality is interpreted to be good, assuming that the Eurekan Orogeny produced quartzose sediment that was deposited in the sedimentary system in Baffin Bay Basin.

Timing and preservation probability. The geological model indicates that timing is favourable in this 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.

The overall geological probability in this AU is the product of the three geological probabilities, or 0.28, which suggests there is a 28% 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 Supplementary Appendix 4. The events chart summarizing the petroleum system elements in this AU is shown in Figure 41.13.

Estimation of sizes and numbers of undiscovered fields

The Revised Deltas Analogue Set (D. Houseknecht, pers. comm., 2008) was used to estimate numbers and sizes of undiscovered oil and gas fields. This data set included deltaic analogues of the world with the salt-dominated deltas removed from the analogue set, making the analogue more comparable to the succession postulated to exist in Baffin Bay Basin. The World Averages Analogue Set was used to estimate co-product ratios and ancillary data.

Numbers of undiscovered oil and gas fields. Numbers of potential undiscovered oil and gas fields were estimated using the Revised Deltas Analogue Set. The median density of oil and gas fields in the Revised Deltas Analogue Set is 0.15 fields/1000 km², and this density was used along with the AU area of 252 000 km² 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/1000 km². The probability distribution for undiscovered oil and gas fields was one 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% at the minimum, 50% at the median to 90% at the maximum. Using these numbers, the number of oil fields was calculated to be one 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 Analogue Set. The median oil accumulation size was estimated to be 120 MMBO, as that size reflected the median of the Revised Deltas Analogue Set. The ‘largest expected oil field size’ was estimated to be about 1 BBO based on the analogue 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.

Co-product ratios and ancillary data

Co-product ratios were estimated using the co-product ratio summaries within the Revised Deltas Analogue Set. Ancillary data were derived from the World Averages Analogue Set. Median gas–oil ratio for undiscovered fields was estimated at 1600 SCFG/BO; median NGL–gas ratio was estimated at 15 BNGL/MMCFG; and median liquids–gas ratio in undiscovered gas fields was estimated 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 publically available bathymetric maps of northern Baffin Bay. Drilling depths for undiscovered oil fields ranged from a minimum of 500 m, a median of 2000 m and a maximum of 5000 m. For undiscovered gas fields, drilling depths were a minimum of 500 m, a median of 2500 m and a maximum of 9000 m. Estimates of water depths for undiscovered oil and gas fields range from a minimum of 0 m, a median of 1500 m, to a maximum of 2200 m.

Greater Ungava Fault Zone AU description

The Greater Ungava Fault Zone Assessment Unit (AU 5, Fig. 41.1) encompasses all petroleum reservoirs in the Ungava Fault Zone, a complex fault zone with a history of extension, transtension and transpression (Skareup et al. 2006; Sørensen 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 NE Canada Rifted Margin AU, to the east by the West Greenland Rifted Margin AU, and to the south by the province boundary (Fig. 41.1). The area of the Greater Ungava Fault Zone AU is about 145 000 km².

Geological model for assessment

The geological model used in the assessment involves petroleum source rocks within the extensional and transtensional basins that...
were buried deep enough to reach thermal windows for oil and gas generation (Fig. 41.14). Petroleum migrated updip and vertically into synrift fluvial and deltaic sandstones and post-rift marginal marine 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 Palaeogene 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 Palaeogene oil. Wells drilled within this or immediately adjacent to this assessment unit are classified as dry holes or have shows. Given the uncertainty on 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 programme.

Rocks probability. The proximity of this AU to the NW Greenland Rifted Margin AU indicates that there is no geological 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. 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 partially lost from the system. Wells drilled within or immediately adjacent to this AU were classified as dry holes or have shows, but they might not have been optimally located to have been an adequate test of the presence of trapped petroleum (Chalmers & Pulvertaft 1992). The geological probability of the presence of a field of minimum size in the Greater Ungava Fault Zone AU is the product of the three geological probabilities discussed above, for an overall geological probability of 0.30. This suggests that there is a 30% chance for proper geological 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 Supplementary Appendix 5. The events chart for the petroleum system elements in this AU is shown in Figure 41.15.

Estimation of sizes and numbers of undiscovered fields

The Architecture–Strike-Slip Analogue Set was used to estimate numbers and sizes of undiscovered oil and gas fields, as well as for the estimation of co-product ratios. The World Averages Analogue Set was used to estimate ancillary data.

Numbers of undiscovered oil and gas fields. The Architecture–Strike-Slip Analogue Set was used to estimate undiscovered oil and gas field sizes. The median oil and gas field density in the Architecture–Strike-Slip Analogue Set is 0.35 fields/1000 km², and along with the total AU area (145 000 km²), 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
Sizes of undiscovered oil and gas fields. The Architecture–Strike-Slip Analogue Set was used in the estimation of sizes of undiscovered oil and gas fields. The median oil field size in the Architecture–Strike-Slip Analogue 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 value was adopted as the median oil field size. Numbers of undiscovered gas fields have the same probability distribution.

Co-product ratios and ancillary data

Co-product ratios were estimated using the Architecture Strike-Slip Analogue Set, and the ancillary data were estimated using the World Averages Analogue Set. Median gas–oil ratio for undiscovered fields is estimated to be 1700 SCFG/BO; median NGL–BCFG; and median 150 at the maximum. The uncertainty of the oil–gas mix led to a maximum oil field accumulation size of 5 BBO. The mean undiscovered oil resource is 9892 BCFG, with an F95 of 0 BCFG and an F5 of 50 625 BCFG. The largest expected oil field size is about 1086 MMBO, and the largest expected gas field size is about 6,485 BCFG.

The NE Canada Rifted Margin AU extends south of the Arctic Circle. For the total area of the AU, the mean undiscovered oil resource is 1431 MMBO, with an F95 of 0 MMBO and an F5 of 5847 MMBO. The largest expected oil 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 2746 MMBO, with an F95 of 0 MMBO and an F5 of 10 900 MMBO. The largest expected oil field size in the AU is about 2273 MMBO, and the largest expected gas field size is about 13 222 BCFG.

Assessment results

The assessment results for the five AUs in the West Greenland–East Canada Province are summarized in Table 41.1. The upper part of Table 41.1 reflects the assessment of the full geographic extent of each AU (Fig. 41.1). Three of the AU 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 41.1).

The Eurekan Structures AU is entirely north of the Arctic Circle. The mean undiscovered oil resource is 1133 MMBO, with an F95 of 0 MMBO and an F5 of 6626 MMBO. Given the AU probability of 0.25, there is a 50% chance that no fields of minimum size exist in this AU (Table 41.1). The mean volume of undiscovered nonassociated gas resource is 6806 BCFG, with an F95 of 0 BCFG and an F5 of 39 428 BCFG. The largest expected oil field size is about 1086 MMBO, and the largest expected gas field size is about 6,485 BCFG.
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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 5037 MMBO. The mean volume of undiscovered nonassociated gas resource is 5852 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 1193 BCFG, with an F95 of 0 BCFG and an F5 of 29 950 BCFG. The largest expected gas field size is about 7164 BCFG.

The total mean undiscovered estimates for the five AUs defined in this study are 10 697 MMBO for undiscovered oil, 74 853 BCFG of undiscovered gas and 1153 MMB of undiscovered NGL resources (Table 41.1). The geological probabilities for the five AUs in this study were determined based on a consideration of the geology of this province.

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Geological knowledge base, and will lead to a refinement of the petroleum systems within the province will greatly add to the geological knowledge of the West Greenland–East Canada Province.

The geological probabilities for the five AUs in this study were determined based on a consideration of the geology of this province, but also on the geological 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 geological 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 geological knowledge base, and will lead to a refinement of these assessment results.

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