

New insights on subsurface energy resources in the Southern North Sea Basin area

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Abstract: The Southern North Sea Basin area, stretching from the UK to the Netherlands, has a rich hydrocarbon exploration and production history. The past, present and expected future hydrocarbon and geothermal exploration trends in this area are discussed for eight key lithostratigraphic intervals, ranging from the Lower Carboniferous to Cenozoic. In the period between 2007 and 2017, a total of 95 new hydrocarbon fields were discovered, particularly in Upper Carboniferous, Rotliegend and Triassic reservoirs. Nineteen geothermal systems were discovered in the Netherlands onshore, mainly targeting aquifers in the Rotliegend and Upper Jurassic/Lower Cretaceous formations. Although the Southern North Sea Basin area is mature in terms of hydrocarbon exploration, it is shown that with existing and new geological insights, additional energy resources are still being proven in new plays such as the basal Upper Rotliegend (Ruby discovery) for natural gas and a new Chalk play for oil. It is predicted that hydrocarbon exploration in the Southern North Sea Basin area will probably experience a slight growth in the coming decade before slowing down, as the energy transition further matures. Geothermal exploration is expected to continue growing in the Netherlands onshore as well as gain more momentum in the UK.

Since the publication of the *Petroleum Geological Atlas of the Southern Permian Basin* (SPB) (Doornenbal & Stevenson 2010), which gave a comprehensive overview based on more than 150 years of petroleum exploration and research from onshore UK to Poland, the basin has continued to see

successful exploration wells drilled together with a diversification of drilling targets. This paper summarizes the activities over the period 2007–17 to give an update on new exploration insights. The focus of this paper is more limited than the entire SPB Atlas area and concentrates on its western part between latitudes

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50° 30' and 56° N and longitudes 1° 45' W and 7° 30' E. This area includes the onshore and offshore UK and the Netherlands (Fig. 1).

For purely descriptive purposes, the saucer-shaped SPB was subdivided into three components by Ziegler (1990): the Anglo-Dutch, North German and Central Polish sub-basins. The area describing the Anglo-Dutch Basin and Mid North Sea High is also called the Southern North Sea Basin (SNSB; Cameron *et al.* 1992; Pharaoh *et al.* 2010). During the Carboniferous, the evolving SNSB was fringed to the north and south by persistent highs, the Mid North Sea High and the London–Brabant Massif (Fig. 1). In the UK sector, the NW trend of both Mississippian basin-bounding extensional faults (Leeder & Hardman 1990; Arsenikos *et al.* 2018) and Variscan inversion structures, is attributed to the extensional and compressional reactivation of major Caledonide lineaments (Corfield *et al.* 1996; Cameron *et al.* 2005). The latter include the NW-trending Dowsing–South Hewett Fault Zone and the Elbe Lineament (Fig. 1), which were probably initiated during closure of the Tornquist Sea (Cocks & Forzey 1982; Pharaoh *et al.* 2010, 2011, 2018; Smit *et al.* 2018) in Late Ordovician time. Further reactivation of these structures occurred in Late Cretaceous and Cenozoic times (Badley *et al.* 1989; Green *et al.* 2018). Cameron *et al.* (2005) recognized a prominent pre-Permian fault set on a west–east trend, also identified on the Cleaver Bank High (Geluk *et al.* 2002). North- and NNW-trending, pre-Permian compressional structures also occur; examples can be found in the Irish Sea (Pharaoh *et al.* 2018), Northumberland (De Paola *et al.* 2005), the Midland Valley of Scotland and Lower Saxony Basin (Kombrink *et al.* 2010).

The paper is organized as follows. A brief overview of the main hydrocarbon plays and petroleum systems in the SNSB area will be presented first, then geothermal plays, followed by a more detailed discussion of the key stratigraphic intervals (Lower Carboniferous, Upper Carboniferous, Rotliegend, Zechstein, Triassic, Jurassic–Lower Cretaceous, Upper Cretaceous and Cenozoic) along the following lines:

- a short historical overview of exploration before 2007 – the SPB Atlas (Doornenbal & Stevenson 2010) captured developments until 2007;
- a short description of newly discovered hydrocarbon fields and commissioned geothermal systems in the period between 2007 and 2017 with special attention to new insights and play concept revisions; and
- a brief outline of new exploration targets and areas of further prospectivity for both hydrocarbon and geothermal resources.

The paper will conclude with a summary and outlook for the future exploitation of hydrocarbon and geothermal resources within the SNSB area.

Hydrocarbon plays and petroleum systems

Approximately 1240 oil and gas fields had been discovered by the end of 2006 within the whole SPB Atlas area (Doornenbal & Stevenson 2010), of which more than 67% were discovered within the study area of the present paper. Since then, 95 new hydrocarbon fields have been found and 19 new geothermal systems have been commissioned in the study area (Figs 1–3). A dataset of these new fields and systems was compiled, including their associated attributes, i.e. field name or geothermal system name, discovery year, discovery well, reservoir age and fluid type (Appendices A and B). Field outlines of the fields discovered before the end of 2006 were provided by the SPB Atlas project (Doornenbal & Stevenson 2010). The dataset and the field outlines of the new fields have been gathered and compiled by information downloaded from public sources: the Netherlands Oil and Gas website for the Dutch fields (<http://www.nlog.nl>) and the Oil and Gas Authority website for the UK fields (<http://data-ogauthority.opendata.arcgis.com>).

Where possible, the data gaps were filled by the authors. The above-mentioned dataset (Appendices A and B) and field outlines are the basis for the various maps in this paper.

Four petroleum systems can be recognized in the SNSB area: (1) Viséan/Namurian source; (2) Westphalian source; (3) Jurassic source; and (4) shallow gas. The first three petroleum systems are based on the age of the main source rock for the oil and gas accumulations.

(1) Viséan/Namurian source (Fig. 2)

Marine shales of Viséan–early Namurian age are the principal source rocks in the ‘East Midlands area and the Cleveland Basin’ petroleum province (onshore Craven and offshore Cleveland groups, including the Bowland Shale Formation) (Pletsch *et al.* 2010). In the East Midlands area, the main oil reservoirs are Namurian and Westphalian sandstones, dependent on intra-formational seals (Pharaoh *et al.* 2010). In the Cleveland Basin, gas is hosted in Zechstein reservoirs, presumably sourced from the Namurian or Westphalian. There may be potential for Namurian shales to be a source for oil along the northern and southern fringes of the SPB where the succession has not been buried too deeply.

(2) Westphalian source (Fig. 2)

The most important petroleum province in the SNSB area is the ‘Anglo-Dutch Basin’, where

the Carboniferous, in particular the Westphalian Coal Measures, provides the principal source-rock interval (Breunese *et al.* 2010). Distribution of these coals and their maturity largely controls the distribution of hydrocarbon accumulations. Another major controlling factor is the presence of upper Permian Zechstein evaporites, the principal seal to the Lower Permian Rotliegend and Zechstein reservoirs. In general, the reservoirs range from Late Carboniferous to Cretaceous in age (Fig. 2).

(3) *Jurassic source* (Fig. 3)

The following petroleum provinces with a Jurassic source can be distinguished (Breunese *et al.* 2010):

- (a) Weald Basin – the oil and gas fields and discoveries found in this basin are considered to have been sourced from mudstones within the Lower Jurassic, the Oxford Clay and the Kimmeridge Clay formations.
- (b) Broad Fourteens and West Netherlands basins – the extent of the oil play in these basins can be delineated by the distribution of the Posidonia Shale Formation source rock, the distribution of the reservoir rocks either of the Jurassic–Cretaceous Delfland Subgroup and Vlieland Sandstone Formation reservoirs or Triassic reservoirs; and the distribution of the main seal(s) formed by the Vlieland Claystone Formation and the Middle Triassic mudstones.
- (c) Dutch Central Graben – the fields have been sourced from the Posidonia Shale Formation. Most oil from this source rock is reservoirized in Upper Jurassic to Lower Cretaceous sandstones. Oil is also found in the Upper Cretaceous Chalk Group, mostly above salt domes.
- (d) Tail End Graben – the discovered fields are considered to have been sourced by shales of the Kimmeridgian Farsund Formation, including the Bo Member ‘hot shale’ unit; the main reservoirs are in Upper Cretaceous limestones of the Chalk Group.
- (e) Lower Saxony Basin – the fields are considered to have been sourced by the Posidonia Shale Formation (gas and oil) and/or by the Wealden Formation (only oil). The main reservoirs are in Jurassic and Cretaceous reservoirs.

The latter two petroleum provinces, i.e. the Tail End Graben and the Lower Saxony Basin, are (mainly) located outside the study area.

(4) *Shallow gas* (Fig. 3)

In contrast to the petroleum systems mentioned above, which are distinguished on the basis of

their source rock, shallow-gas occurrences are characterized by the depth of the reservoir. Shallow gas is commonly defined as gas accumulations in sediments down to depths of 1000 m below the surface, although the petroleum industry tends to be pragmatic, regarding it as gas above the first casing point. Shallow gas in the SNSB area is mainly of microbial origin (also referred to as ‘biogenic’), with minor contributions of thermogenic gas from older source rocks (Pletsch *et al.* 2010).

Geothermal plays

Since the publication of the SPB Atlas in 2010 significant progress has been made in the development of geothermal energy resources in the Netherlands. The Dutch hot sedimentary aquifers from which geothermal energy is extracted could be classified as a ‘hydrothermal’ or an ‘intra-cratonic conductive’ geothermal play (Moeck 2014) or as a low-enthalpy geothermal play (Dickson & Fanelli 1990); depending on the ‘point of view’, these three play classification systems are related to permeability system, tectonic setting or temperature, respectively. Before 2008, there was no geothermal energy production, whereas in 2017, 3.04 PJ per year was generated from 14 producing installations (Figs 2 & 3, Appendix B). Another five geothermal systems were discovered but are still in the process of commissioning (MEA 2018). All systems are for the purpose of Direct Use with the main focus on heating greenhouses (MEA 2018). At the time of writing (end-March 2019), only one geothermal system is in production in the UK: the Southampton Direct Use project. This system started production in 1986, produces heat from Triassic sandstones and is integrated in the district heat network. Another long-term initiative in the UK has been the search for hot dry rock geothermal energy in Cornwall from deep-seated fractured granite reservoirs. The United Downs project, operated by Geothermal Engineering Limited (GEL), has secured funding of £10.6 million from the European Regional Development Fund to explore this resource. With £2.4 million from Cornwall Council and £5 million from private investors, the funding will allow GEL to drill two deep geothermal wells from its site within the United Downs Industrial Estate and build a 1–3 MW pilot power plant to demonstrate the technical and commercial viability of supplying both electricity and heat (Anonymous 2018b). At the time of writing the first well of the doublet has reached 4000 m depth and is on track to becoming the deepest onshore borehole in the UK. Another proposed geothermal plant at the Eden Project site is currently raising funding prior to execution (Anonymous 2018c).

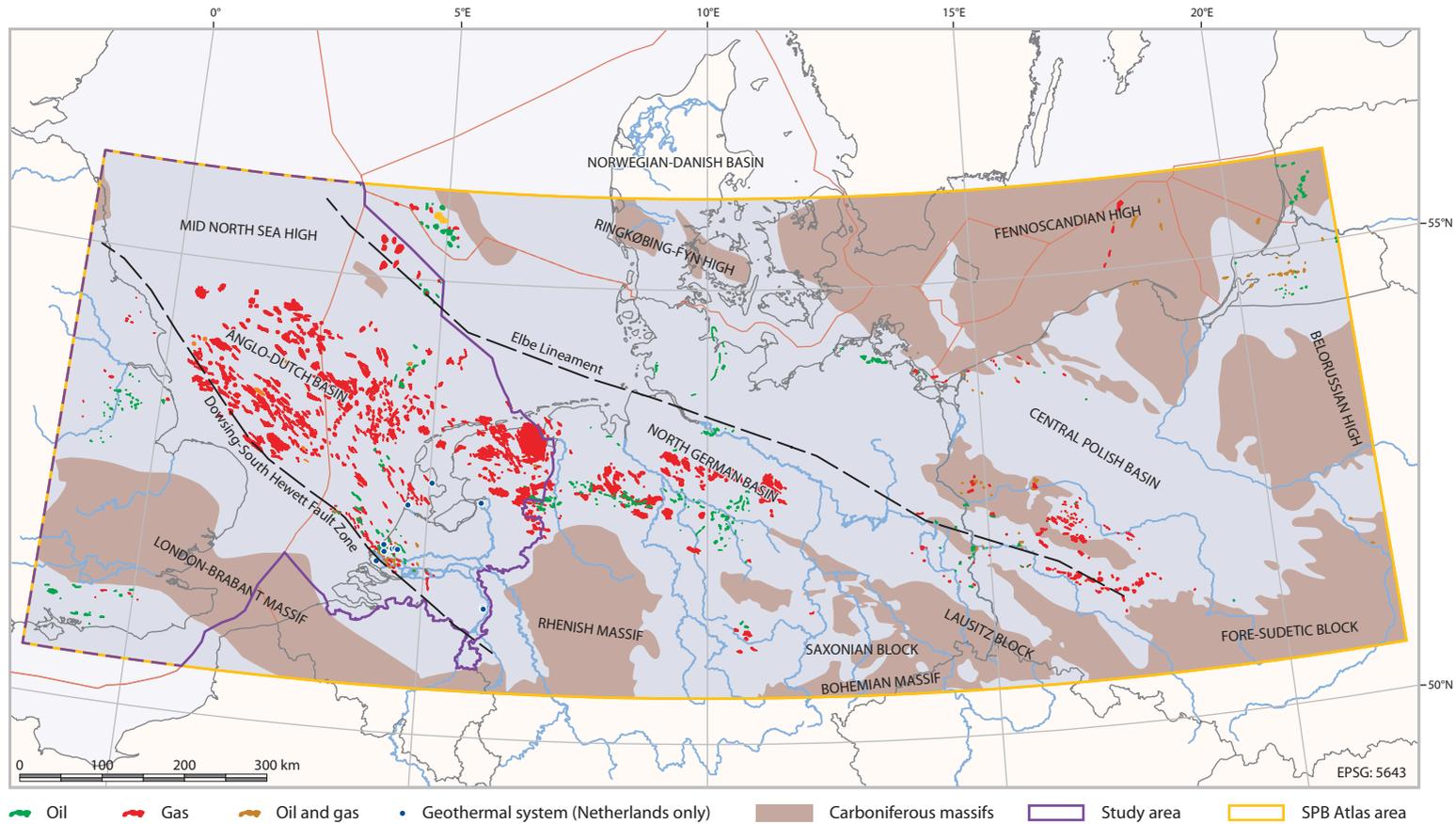


Fig. 1. The distribution of the 1240 hydrocarbon fields discovered before 2007 within the Southern Permian Basin (SPB) Atlas area (revised from Doornenbal *et al.* 2010). The purple polygon shows the study area for this paper (Southern North Sea Basin (SNSB) area) and also includes the 95 hydrocarbon fields discovered in the period 2007–17, as well as the 19 geothermal systems developed in the same period. In general, the distribution of the hydrocarbon fields shows that most are concentrated between the Dowsing–South Hewett Faultzone and the Elbe Lineament (Pharaoh *et al.* 2010, fig. 3.3).

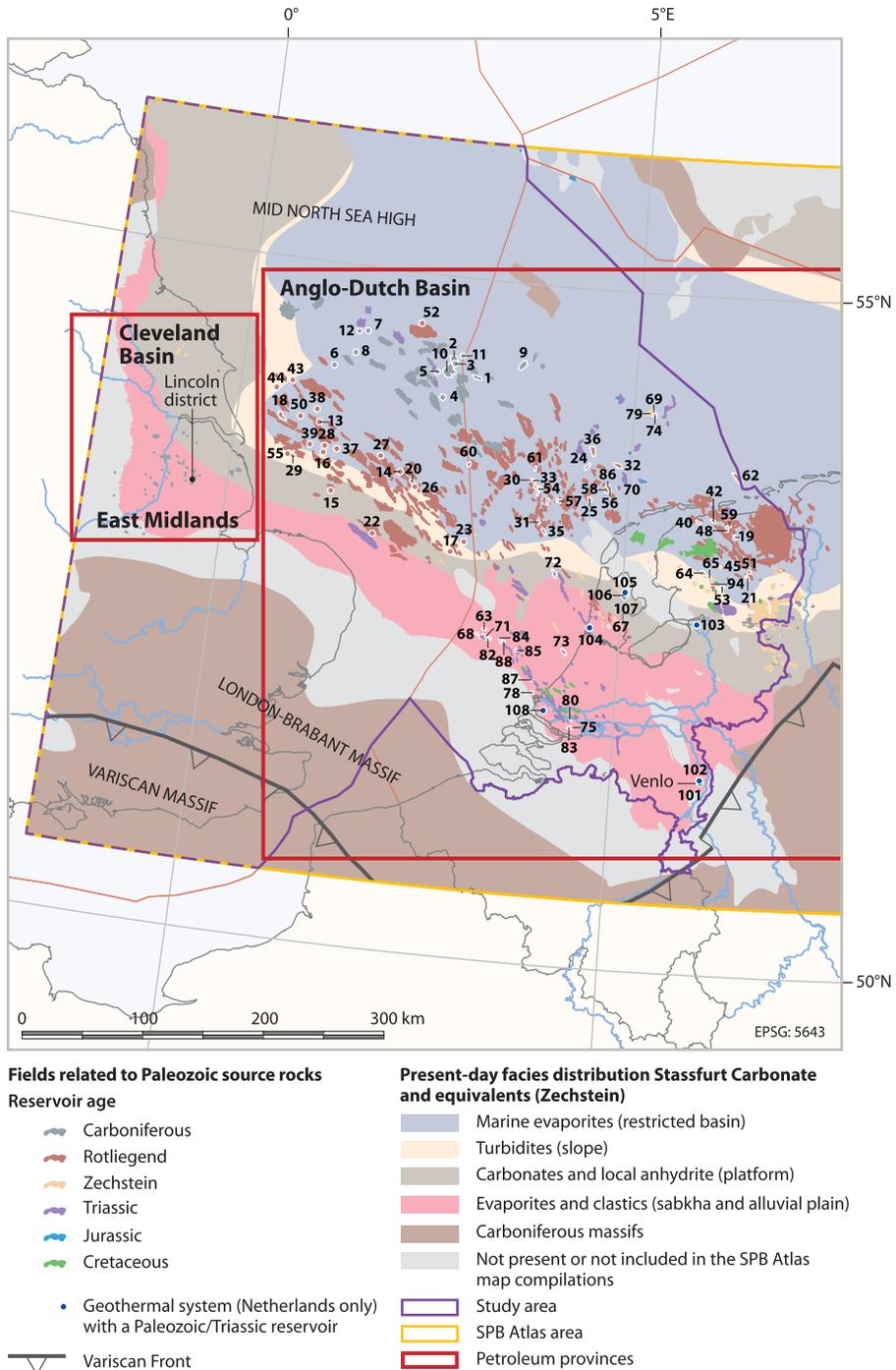


Fig. 2. Overview of petroleum provinces within the study area related to Paleozoic source rocks (revised from Breunese *et al.* 2010). The hydrocarbon fields discovered and the geothermal systems completed in the period 2007–17 are numbered and refer to [Appendices A and B](#). The purple polygon shows the outline of the present study area. The orange box shows the outline of the SPB Atlas area (Doornenbal *et al.* 2010). Red boxes show the simplified shapes of the main petroleum provinces.

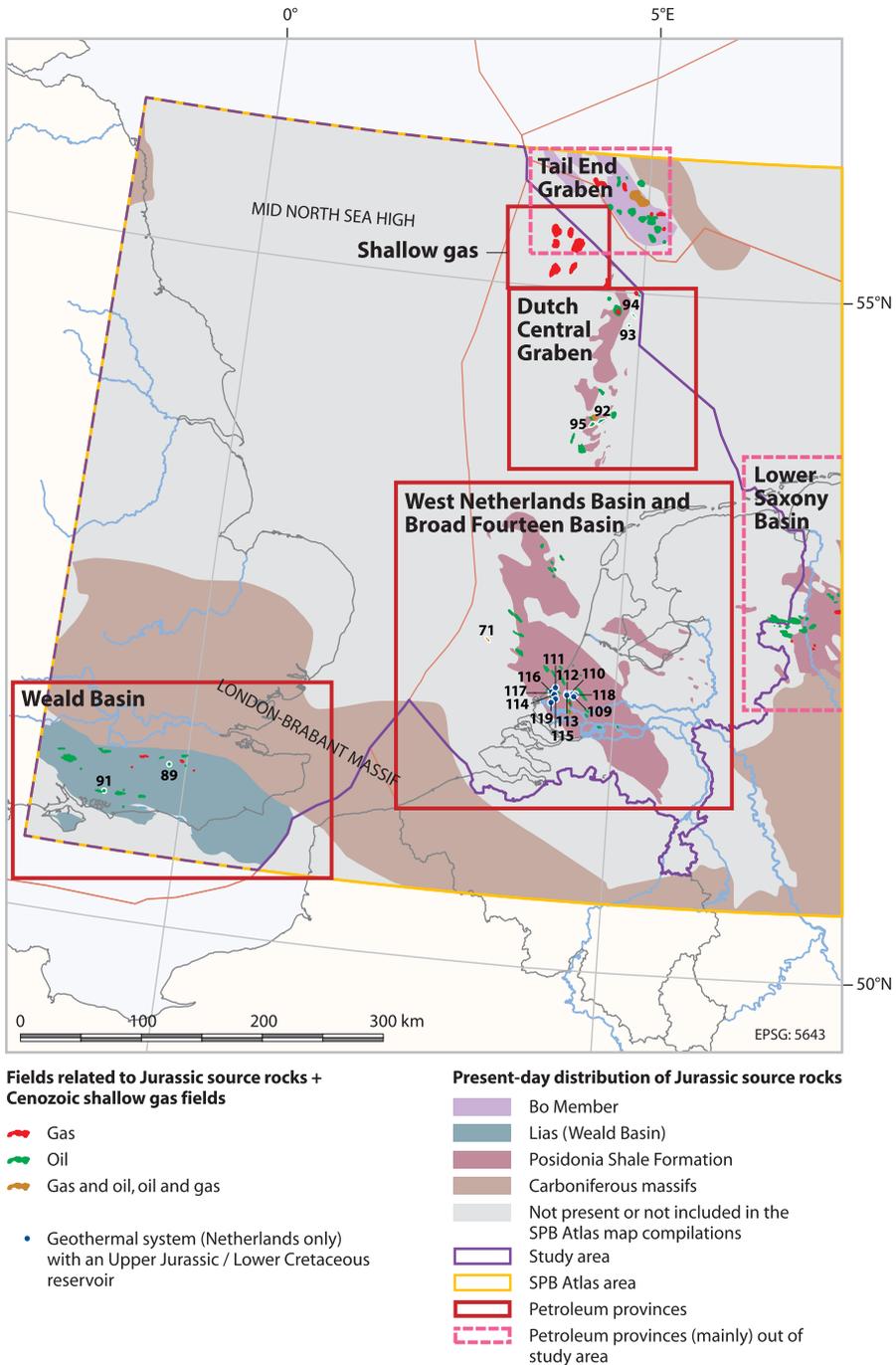


Fig. 3. Overview of petroleum provinces within the study area that are related to Jurassic source rocks. Also indicated is the area where shallow Cenozoic fields have been found (revised from [Breunese et al. 2010](#)). The hydrocarbon fields discovered and the geothermal systems completed in the period 2007–17 are numbered and refer to [Appendices A and B](#). The purple polygon shows the outline of the present study area. The orange box shows the outline of the SPB Atlas area ([Doornenbal et al. 2010](#)). Red and pink boxes show the simplified shapes of the main petroleum provinces.

One of the key success elements in Dutch geothermal development is the project setup where the geothermal operator producing the heat has a guaranteed demand as an integral part of individual or clustered greenhouse energy transition projects. Additionally, financial support and guarantee schemes were effective in the relatively high development pace (Mijnlieff *et al.* 2013).

For efficient and sustainable development of geothermal systems, the same play elements as for exploration and production of hydrocarbons must be evaluated. Potential reservoirs for geothermal systems are the same as those targeted by hydrocarbon exploration and production: porous and permeable sandstones and carbonates. As a rule of thumb, the permeability thickness of the reservoir needs to be higher than 10–15 Dm. As porosity and permeability in siliciclastic reservoirs are strongly correlated with depth and facies, these are key parameters in the evaluation of geothermal reservoirs (Van Kempen *et al.* 2018). Cenozoic, Upper Jurassic–Lower Cretaceous, Triassic, Rotliegend and even Lower Carboniferous reservoirs are all proven geothermal reservoirs (MEA 2018). The presence of an active hydrocarbon source rock is generally regarded as a risk as it might compromise the likelihood of finding only hot water, and if gas and/or oil are present it will complicate production. All but two of the commissioned geothermal systems are situated within the mature Dutch oil and gas provinces, for example the West Netherlands Basin and Noord-Holland Platform. They all produce solution gas (methane) as a by-product of the hot-formation water, in a gas–water ratio of 1–2 m³/m³. Moreover, one system did produce oil as a co-product of water production (MEA 2018). The presence of an aquitard, resembling a seal in oil and exploration and production, is a necessity for efficient and Health, Safety and Environment (HSE)-compliant production performance. A key issue in a multiwell geothermal system is circulation through the aquifer from the injection well to the production well. The aquitard effectively guides the flow through the aquifer instead of dissipating it to shallower strata close to the injection well. Closed (relative high) structures, essential for hydrocarbon accumulations, should be avoided in geothermal exploration. Firstly, because of the risk that hydrocarbons could be encountered, and secondly as geothermal wells aim for the highest accessible temperature, downdip and graben settings are more obvious target locations for the production well. The newly available data from more deeply buried reservoirs in geothermal wells resulted in better understanding of reservoir distribution, for example of Upper Jurassic and Lower Cretaceous fluvial reservoirs in (palaeo-)graben settings (Franz *et al.* 2018). Circulating vast volumes of formation water under changing conditions of temperature, pressure

and composition owing to, for example, degassing, poses challenges for the prevention of scaling and corrosion of the installation. Key to this issue is understanding of the formation water composition per play, depth and facies and its reactivity with the geothermal installation.

Lower Carboniferous

With regards to Carboniferous stratigraphic nomenclature used in this paper, we decided to maintain the regional stratigraphical subdivision of ‘Lower Carboniferous’ and ‘Upper Carboniferous’ with the boundary at the base of the Namurian Stage (Kombrink *et al.* 2010).

History of exploration

In large parts of the SNSB area, the Lower Carboniferous is deeply buried and poorly known. However, onshore UK and along the northern and southern border of the SPB the sequence occurs at shallower depths. The Lower Carboniferous succession encountered in the SNSB area represents the infill of a series of major rift basins that were initiated during Late Devonian time (Fraser & Gawthorpe 1990). This succession exhibits a variety of lithologies and facies associations, with predominant paralic siliciclastic deposition in the north around the Mid North Sea High area, and deeper-water platform carbonates fringing deeper mudstone facies in the south (Ziegler 1990). The exact relationship between the carbonates in the south and the siliciclastics in the north is largely unknown.

Towards the north, around the Mid North Sea High, Lower Carboniferous (Visean) coals and lacustrine–shallow-marine mudstones of the Scremerston Formation are potential source rocks (Monaghan *et al.* 2017). Basal Namurian hot shales of the UK offshore Cleveland Group and onshore Craven Group are correlative with the Geverik Member of the Epen Formation in the Netherlands (Schroot *et al.* 2006). These are often considered as the potential source rock from which hydrocarbons could laterally migrate into the Dinantian (carbonate) reservoirs. However, in most places these source rocks are overcooked owing to Late Carboniferous deep burial. In the southern part of the Netherlands the Lower Carboniferous rocks appear immature and only the deeper basinal areas, i.e. further north and in the UK sector, reached full maturation during deep Carboniferous burial. Without discoveries that prove charge from Lower Carboniferous source rocks, the petroleum system is still unproven for the Netherlands. In 1919, the Hardstoft well was the first oil discovery in onshore England (Total-E&P-UK 2007; DECC 2013). Since then,

only insignificant amounts of oil have been produced from the Dinantian limestones.

Renewed exploration for petroleum systems in the Lower Carboniferous carbonates of NW Europe started in the 1980s. The wells drilled in this phase are clustered around the margins of the Carboniferous basins (Van Hulst & Poty 2008; Kombrink *et al.* 2010). Oil shows were recorded in well 53/12-2 in the UK offshore (Cameron 1993b). Two important attempts to prove hydrocarbons in Lower Carboniferous carbonates in the centre of the SNSB were carried out in the early 2000s when the wells Luttelgeest-1 and Uithuizermeeden-2 tested deeply buried carbonate build-ups in the north of the Netherlands. Both wells failed to test positively.

Total-E&P-UK (2007) also recognized a possible lead in Dinantian carbonates located on the Winterton High, which has, however, not yet been drilled. Despite the lack of proven economic hydrocarbon occurrences in the SNSB area, the Dinantian carbonates are still considered to have remaining exploration potential (e.g. Cameron & Ziegler 1997; Van Hulst & Poty 2008; DECC 2013; Jaarsma *et al.* 2013).

New discoveries since 2007

No hydrocarbons have been proven in Lower Carboniferous rocks since 2007, but hydrothermal exploration resulted in some interesting finds. Two geothermal systems were drilled in Dinantian carbonates near Venlo, in the SE of the Netherlands, in 2012 and 2016 (numbers 101 and 102 in Fig. 2 and Appendix B). As the matrix permeability is very low, commercial flow rates rely on the presence of fractured and/or karstified limestones (Poty 2014) that can improve reservoir properties. The two systems near Venlo produce water at 75°C from a faulted and fractured Dinantian limestone sequence; the position of the injection well is away from the fault into karstified and fractured limestone (Fig. 4). In contrast to the hot sedimentary aquifer hydrothermal play that relies on matrix permeability, these geothermal systems target sedimentary aquifers in which the main permeability field is caused by fracture and fault permeability. Consequently, these reservoirs are classified as a conductive intracratonic rift play (CD1_R) (Moeck 2014). Geothermal systems in these plays have a higher induced seismicity hazard in the geothermal exploitation phase with respect to geothermal systems in hot sedimentary aquifers with matrix permeability.

Future trends and developments

Recently, Ter Borgh *et al.* (2018) argued that hydrocarbon potential exists for the Namurian and Viséan plays in the northern Dutch offshore. Here the presence of Dinantian source rocks (coals of the

Scremerston Formation in the UK sector or Elleboog Formation in the Dutch sector) is uncertain since they have never been drilled. However, seismic mapping of this interval from the UK sector southward into the northern part of the Dutch sector (Blocks A, B) suggests that this source rock is widespread and potentially significant also for the Central and Northern North Sea area. Basin modelling shows that the Scremerston source rocks generally enter the hydrocarbon generation window during Cenozoic burial (De Bruin *et al.* 2015). This late generation and the presence of several Carboniferous and younger reservoirs with favourable trapping geometries indicate the potential for future discoveries.

A re-evaluation of the Dinantian (Tournaisian and Viséan) petroleum system (Jaarsma *et al.* 2013) on the northern flank of the London–Brabant Massif showed a cluster of leads in Dinantian carbonates on the Winterton High (a high straddling the UK–Netherlands median line), and further possibilities may exist in carbonate platforms and reef complexes underlying the Hewett Shelf in the UK sector. Recently, Jetex Petroleum was awarded an exploration licence in the Dutch offshore P blocks that covers five prospects in Dinantian limestones. In the UK sector of the Winterton High ENI UK holds a selection of blocks covering the same play. The Winterton High Dinantian limestones form one of the few undrilled plays in the Netherlands.

In the larger part of the onshore Netherlands, the Dinantian carbonate sequence is buried to depths of more than 4 km. From these depths, water can be produced in excess of 120°C for application in industrial processes and large-scale heating of the built environment. A potentially significant new development is the exploration of Dinantian carbonates for these purposes. From Belgium, several occurrences of Dinantian carbonates with good reservoir properties were already known, including the underground gas storage facility near Loenhout (Amantini 2009) and the Merksplas–Beerse geothermal system (Vandenbergh *et al.* 2000). Both utilize a karstified Dinantian reservoir with porosities up to 20% and 2 D permeabilities. In Loenhout, the cavernous karst produced metre-scale cavities that are partly cemented by carbonaceous cement and sometimes filled with high gamma-ray Namurian shales that also overlie the top of the Dinantian (Amantini 2009).

In several wells and on seismic profiles from the northern flank of the London–Brabant Massif, further evidence for major karst features (intra- and top platform) was identified (Reijmer *et al.* 2017). In the Lincoln district of the East Midlands province in the UK, Dinantian carbonates typically are at depths between 1500 and 2500 m (Pharaoh *et al.* 2011). This area was uplifted in Namurian times and Westphalian strata have been deposited there

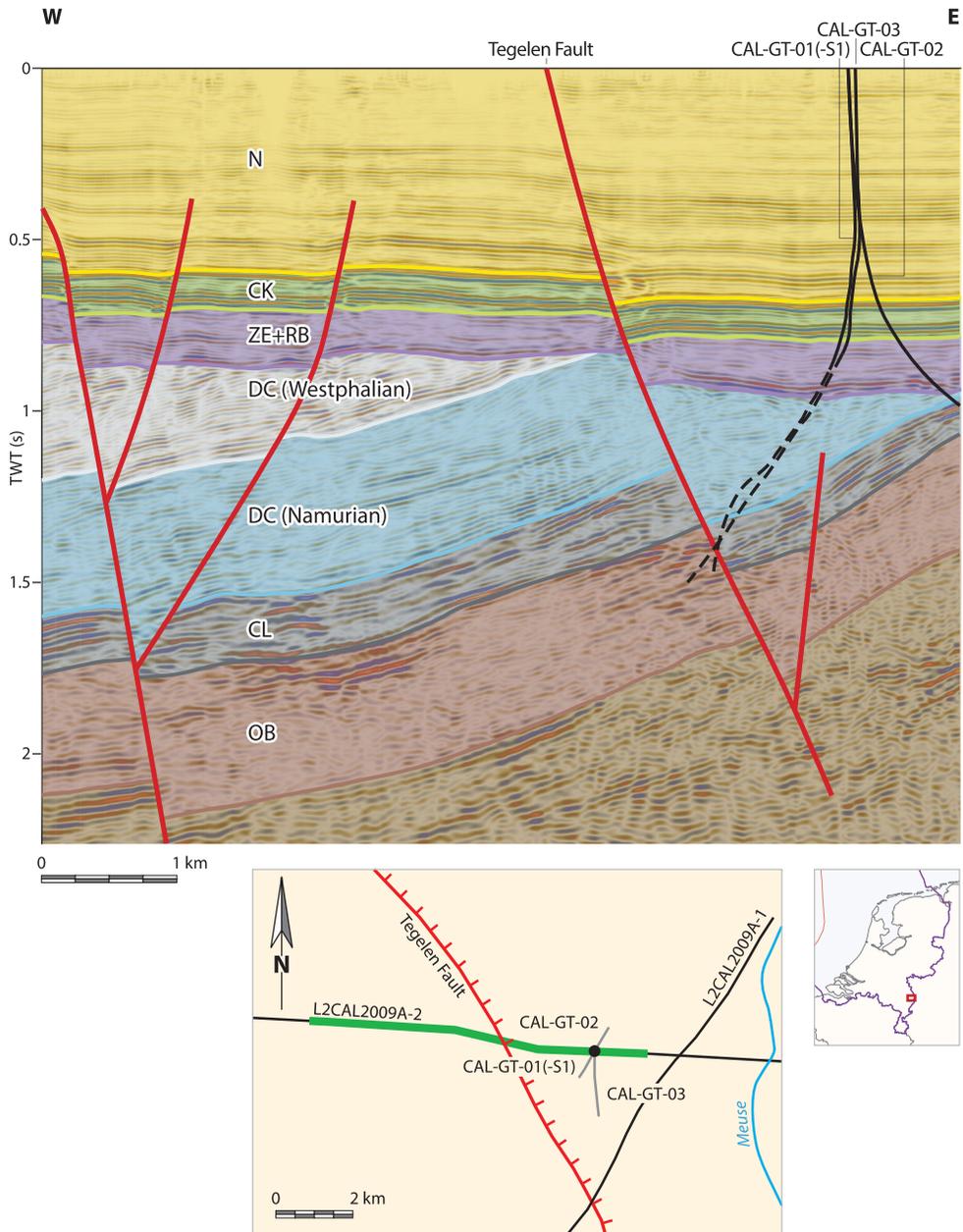


Fig. 4. West-east seismic line (freely available at <http://www.nlog.nl>) over the ‘Californie Geothermie’ system (no. 101 in Appendix B) near Venlo in the SE of the Netherlands. Well CAL-GT-01-S1 acts as producer and targets faulted and fractured Lower Carboniferous (Dinantian) limestone in and around the Tegele Fault. The anticipated injection well (CAL-GT-02) is away from the main faults, but after its collapse injection was relocated to the anticipated second producer well CAL-GT-03. Note that the well-heads and -trajectories are out of section and therefore projected on the seismic line parallel to the strike of the Tegele Fault. Inset shows locations of wells, seismic line (highlighted part indicates part shown), and the surface trace of the Tegele Fault. Seismic interpretation is tentative owing to limited well control, structural complexity and the likely presence of seismic artefacts. N, North Sea Supergroup Cenozoic; CK, Chalk Group (Late Cretaceous); ZE + RB, Zechstein & Lower Germanic Trias Group (Permian-Triassic); DC, Limburg Group (Westphalian + Namurian); CL, Carboniferous Limestone Group (Dinantian); OB, Banjaard Group (Devonian-?Dinantian).

on eroded/karstified Dinantian carbonates. Core porosities of 5–20% were obtained in several boreholes in the region (DECC 2013), but the geothermal potential is presently unknown.

Further research to test the potential of the ultra-deep geothermal energy potential of Dinantian carbonates in the Netherlands is ongoing and will hopefully lead to one or more pilot wells to test the production and injection capabilities of these reservoirs.

Upper Carboniferous

History of exploration

The Carboniferous was one of the main targets in the early days of hydrocarbon exploration in the UK and the Netherlands onshore. In the UK, this was based on the presence of prolific Carboniferous reservoirs in the Midlands and shale oil in Scotland (Besly 2018). Therefore, it is not surprising that the very first well drilled in the UK offshore (38/29-1, 1965) targeted Carboniferous rocks of the Mid North Sea High. However, this well proved disappointing, together with a few more dry wells drilled at similar targets, and the Carboniferous was soon concluded to be unprospective for hydrocarbon exploration during this phase (Besly 2018). In the Netherlands, the discovery of gas in the Coevorden Field (1948) triggered exploration in the NE of the country, leading to a cluster of additional discoveries around that field. For both the UK and Dutch offshore areas, it was only after the majority of the Rotliegend gas fields were found that exploration of the Upper Carboniferous started again in the 1980s. As the Rotliegend of the southern margin of the SPB is replaced in a northerly direction by the (evaporitic) Silverpit shales, it was realized that there was potential for Carboniferous reservoirs to be sealed by the Silverpit shales and sourced from the same Westphalian and Namurian mudstones and coals as the gas produced from Rotliegend reservoirs further south. This proved correct and, from the early 1980s to 2007, a string of discoveries were made in this play (the Anglo-Dutch petroleum system or Silverpit play, see Fig. 2), many of which continue to be producing until today. The most important reservoirs encountered in the area occur in fluvial channel sandbodies of Westphalian age, supplemented by stacked fluvial channel sandbodies and incised valley fills and associated facies of Namurian and Viséan age (Besly 2018), such as in the Breagh Field (Symonds *et al.* 2015). The latter field, which was discovered in 1997, comprises a faulted structural closure of Yoredale Formation sandbodies beneath a Zechstein seal (Symonds *et al.* 2015). The Namurian Millstone Grit sandstones have relatively poor reservoir properties.

However, commercially producible reservoirs have been encountered in the Trent and Pegasus fields, in a quartz-arenitic facies for which no clear onshore analogue is known (Besly 2018).

New discoveries since 2007

Looking at wells targeting the Upper Carboniferous since 2007 (Fig. 5), it is primarily the Silverpit play area where exploration has taken place. Although the details of all discoveries in the period 2007–17 are not known, it is thought that most are characterized by four-way dip closures sealed by or subcropping against the claystones of the Silverpit Formation. An example of the former is the Fulham well (44/28a-6) drilled in 2010 to test a simple four-way closure at top Carboniferous level. Unfortunately, the gas–water contact was found to be shallower than hoped and therefore the gas volume (0.77 bcm P50) in Westphalian B sandstones was considered uneconomical (Centrica 2010). In some cases, such as the Severn (43/18a-2Y) truncation-trap prospect, a well was drilled that also required a base seal because of the risk of gas migration further updip. This concept proved to be wrong, as thicker and older sands were encountered than anticipated, probably causing updip gas migration away from the mapped structure (RWE 2015).

Although the Permian Silverpit shales are known to be the ultimate seal to most of the fields in the UK and Dutch North Sea sectors, intra-Carboniferous sealing is required in some cases to explain the presence of producible hydrocarbons. From discoveries in wells 48/23-3 (Blythe) and 48/24a-3 (Wherry; not shown on the map in Fig. 2 as these discoveries pre-date 2007), it is clear that the Carboniferous contains seals that are able to isolate a deep reservoir layer from the regional Rotliegend sand blanket (Besly 2018). This is also the case in the Cavendish Field. The Pegasus North accumulation (43/13b-6) drilled in 2010 represents another example of a field that relies on a combination of intra-Carboniferous and Silverpit sealing.

Carboniferous reservoir gas has also been sought beneath Rotliegend fields. In 2017 BP tested the Carboniferous below the Ravenspurn Field through drilling well 43/26a-E12. Although the details of the operations have not been released, it is likely that the well did not encourage further exploration as the licence was relinquished. In the case of the Cygnus Field (Fig. 5), where the main reservoir is the Permian Leman Sandstone Formation, the Westphalian Ketch Formation proved to be gas-bearing in well 44/12a-3 (Catto *et al.* 2018). This was a contributing factor in the decision to develop the field in 2012.

In the Dutch sector, the Vincent discovery (E11-01; 2014) in Westphalian A sandstones was

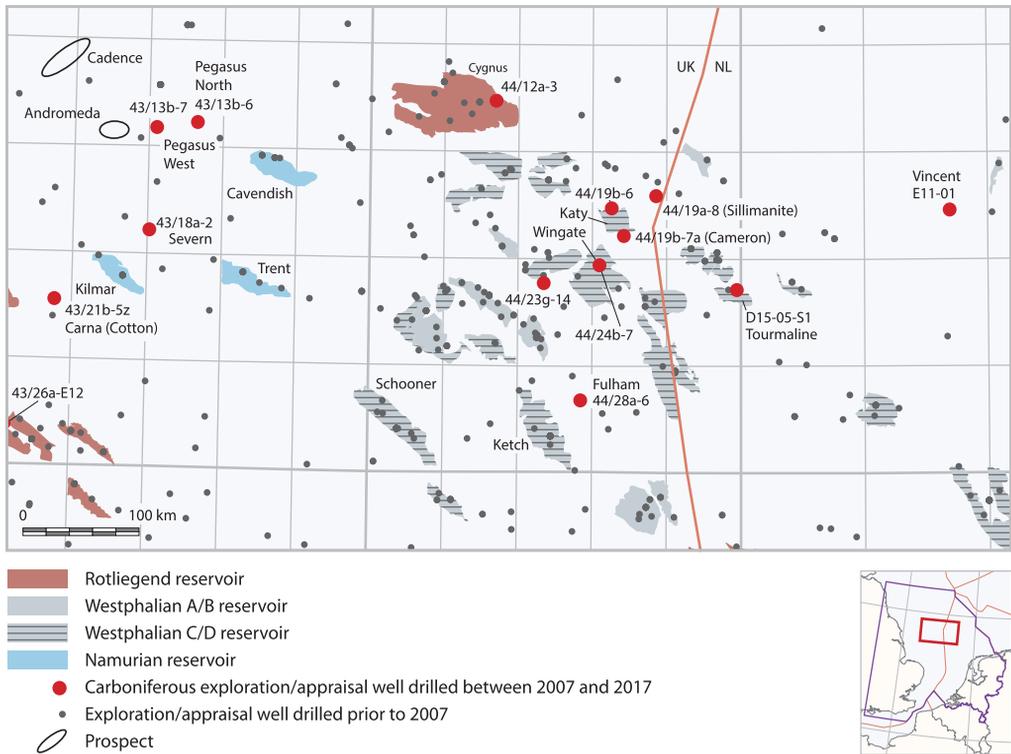


Fig. 5. Location of the most recent exploration and appraisal wells drilled in the Carboniferous Silverpit play area, names of the associated discoveries, and existing field outlines in the Carboniferous Silverpit play area.

probably the most interesting find. The well encountered a 39.6 m gas column and tested at 1.8×10^6 m³/day but remains to be developed. Most drilling activity over the 2007–17 period took place in UK waters, however. A possible reason for this is the perceived risk of elevated nitrogen contents observed in some Carboniferous exploration wells in the Dutch sector.

In summary, during the period 2007–17 the Upper Carboniferous reservoirs of the Silverpit play area have continued to deliver exploration successes, both in the traditional Silverpit play and in cases where intra-Carboniferous sealing played a role.

Future trends and developments

Although it is unlikely that the volumes of produced gas from the Upper Carboniferous in the SNSB area will be offset against new finds in the future, the area still holds potential. Spirit Energy will drill the Namurian Andromeda prospect west of Pegasus in 2019. This may lead to a tie-back to the Cygnus Field, thereby extending the life of this new hub in the northern part of the SNSB area. The Oil and Gas Authority awarded a licence to Speedwell

Resources in the 2016 Supplementary Offshore Licensing Round which aims to develop the Carna (now renamed to Cotton) undeveloped discovery in Namurian sandstones (43/21b-5z). Cluff Natural Resources identified the Cadence prospect in Namurian and Lower Carboniferous sandstones to the NW of the Andromeda prospect, which is just another example of the potential that still exists in the basin. See Figure 5 for the location of these and other Carboniferous prospects.

Based on the exploration success of the last 10 years, it seems likely that future exploration in the area will focus on (1) infill opportunities in the Westphalian C/D cluster that straddles the UK/Dutch median line, (2) pushing the Namurian and Lower Carboniferous play farther to the WNW with respect to the Cavendish and Trent fields and (3) potentially extending the Vincent play proven in the Dutch sector.

Besly (2018) published a paper on the Carboniferous plays in the SNSB area. Whilst an in-depth discussion of his findings is beyond the scope of this contribution it is worth mentioning that he challenges the widely perceived concept that it is only the Westphalian coals that are responsible for

generating Carboniferous-sourced gas. He argues for the possibility of deeper horizons being at least of equal importance, which would extend the area of source rock presence further northwards. Extensive datasets to support this argument were synthesized by the 21st Century Exploration Roadmap Palaeozoic Project (e.g. Arsenikos *et al.* 2015; Monaghan *et al.* 2015; Vane *et al.* 2015; Vincent 2015). This project mapped a wider extent of prospective Viséan–Namurian petroleum system elements than previously recognized, along with organic geochemistry and basin modelling that indicated Paleozoic and Cenozoic oil and gas generation in areas adjacent to and north of existing Southern North Sea gas fields, and highlighted future exploration opportunities.

Rotliegend

History of exploration

The discovery of the vast Groningen gas field in 1959 triggered exploration activity targeting the Rotliegend play in both the UK and Dutch offshore and onshore areas. The combined high-quality aeolian to fluvial reservoir of the Slochteren Formation along the southern fringe of the SPB, the extensive presence of Westphalian source rock and the high sealing potential of the overlying Zechstein salt sequences made the Rotliegend a highly profitable play in which most structures are simple horst blocks. The northern limit of the Upper Rotliegend fairway is bounded by the shaling out of the Slochteren Formation and equivalent Leman Sandstone Formation into the Silverpit Formation, while the southern limit is a relatively hard boundary beyond which the absence of salt in the Zechstein results in the lack of an effective top seal. All in all, the total gas volume in the Rotliegend play in the Netherlands and UK is greater than that in all other plays combined (De Jager & Geluk 2007).

Several Rotliegend gas fields were developed in the onshore of the Netherlands during the 1960s. In the offshore UK and the Netherlands drilling started slightly later, in the late 1960s. In the UK the Hewett Field was discovered in 1965, closely followed by the giant Leman gas field located offshore Norfolk in 1966. The latter came on stream as the first producing gas field in the offshore Anglo-Dutch Basin in 1968. The following years saw a variety of Rotliegend fields being drilled both in the UK and the Netherlands. First gas from the Dutch offshore took place in 1975, with the large L10 Rotliegend gas field coming on stream. Activity continued steadily until the rise in gas price in 1981 and saw exploration drilling reaching an all-time high in the 1990s owing to the extensive implementation of 3D seismic acquisition. A decline can be observed

from the second half of the 1990s, when the most attractive prospects were drilled.

The result of this exploration activity is a high-density network of fields along the ENE–WSW-trending fairway crossing from the UK SNSB area into the Dutch onshore (Figs 1 & 2). The Rotliegend play was and remains the mainstay of exploration in the UK and Dutch SNSB area. A comprehensive review of present-day knowledge on the Permian Rotliegend was recently published (Grötsch & Gaupp 2011).

New geological insights and discoveries since 2007

Continued near-field exploration and redevelopment in both UK and Dutch sectors. Most of the 51 fields found in the period 2007–17 (Fig. 2, Appendix A) are located in the classic fluvial to aeolian sediments of the Anglo-Dutch Basin deposited on the southern flanks of the SPB. This supports a trend often seen in mature basins where exploration is focused on near-field and relatively small-size opportunities to maximize the lifespan of infrastructure in place within the known fairways. A departure from this trend of smaller discoveries was the major Tolmount field discovery in 2011 within the Rotliegend fairway.

Despite the trend towards smaller near-field exploration, several interesting new discoveries have been developed. Although it has been known for some years that reservoir-quality sands were also present along the northern margin of the SPB, it is only recently that the first gas field – Cygnus – from this area has started producing. This large gas field was discovered as early as 1988, but it needed a full reassessment, including additional appraisal wells, to conclude that reservoir quality was appropriate and to proceed to development in 2012 (Catto *et al.* 2018). Production from Cygnus started in 2016. The L02-9 HPHT exploration well by NAM was a disappointment, probably owing to poor quality reservoir.

An interesting find is the Fizzy gas field (UK) and the analogue Oak Field (discovered before 2007), both having a fault-dip closure configuration on the Fizzy Horst (Yielding *et al.* 2011). Both fields contain extremely high CO₂ percentages, up to 50% for the Fizzy Field. Whilst the source of the high CO₂ remains uncertain, the fields provide interesting analogues for assessing potential leakage risk from similar reservoirs that are proposed for long-term permanent Carbon Capture and Storage (CCS) (Miočic *et al.* 2014).

Hansa Hydrocarbons (now Oranje Nassau Energie) discovered the Ruby Field in 2017 with reported gas reserves of *c.* 6 bcm (Fig. 6). The discovery opens a play within the basal Slochteren Clastics

(Upper Rotliegend Group) that straddles the German–Dutch median line and shows that local sandstone accumulations overlapping on to the Base Permian Unconformity have hydrocarbon-bearing potential in the area (Fig. 6) (Corcoran & Lunn 2014). The Basal Slochteren sands have been directly mapped on an acoustic impedance inversion cube (Burgess *et al.* 2018), which may also be possible for other prospects in the immediate area. However, the non-unique nature of acoustic impedance does require care in assessing hydrocarbon potential, as was shown in the disappointing second Basal Slochteren well drilled in 2018.

Geothermal plays. Onshore in the Netherlands, five Slochteren Sandstone geothermal systems (see Appendix B) were drilled in the predominantly aeolian facies surrounding the Texel–IJsselmeer High (Fryberger *et al.* 2011; Van Ojik *et al.* 2011) at depths between 1800 and 2700 m. Average permeabilities of the reservoirs are reported to be in the order of 50–250 mD with thickness values of 90–210 m. These result in permeability–thickness or transmissivity values of 10–20 Dm, which depending on the geothermal system design cater for a flow of 150–300 m³ h⁻¹ and installed power of 7–17 MW_{th}. The presence and gross thickness of the Rotliegend appear to be well constrained. The assessment of the net thickness is more complex. The presence, for example, of anhydrite-cemented beds in the Koekoekspolder system reduces the effective reservoir thickness significantly (Henares *et al.* 2014). Apart from the presence of solution gas, the presence of trace amounts of Pb²¹⁰ ions in formation water has caused operational problems. It appears that the lead reacts with the casing and liner steel to form metallic lead which in turn causes obstructions to the flow. Remedial actions, however, appear to be successful, resulting in a sustainable operational system. In the UK onshore, the Cleethorpes borehole was drilled in 1983 to assess the low-enthalpy resource in the aeolian Permian Yellow Sands (Rotliegend). The well is considered to have failed owing to the presence of unusually thin reservoir in an intra-dune location.

Future trends and developments

Continued maturation of remaining Rotliegend prospects and discoveries in the vicinity of existing high-density infrastructure is expected. This near-field exploration and development will keep the infrastructure up and running. This may turn out to be of importance, as the infrastructure is needed for the significant CCS plans developed by the Netherlands (EBN-&Gasunie 2018). CCS is also recognized as a key technology for enabling low-carbon transition in the UK (CCUS-CCTR 2018). The UK

sector of the SPB comprises CO₂ storage opportunities in depleted Permian gas fields (Bentham *et al.* 2014). The many abandoned Rotliegend gas fields may thus be given a second life as permanent CO₂ storage.

The Upper Rotliegend basin margin northern play, as shown by the Cygnus Field, on the northern fringe of the SPB, has potential, although the recently drilled Fault Block 9 well NE of the field turned out to be dry. Regarding the Basal Slochteren play, following up from the Ruby discovery, Oranje Nassau Energie is expected to drill additional identified prospects in the vicinity of the Ruby discovery.

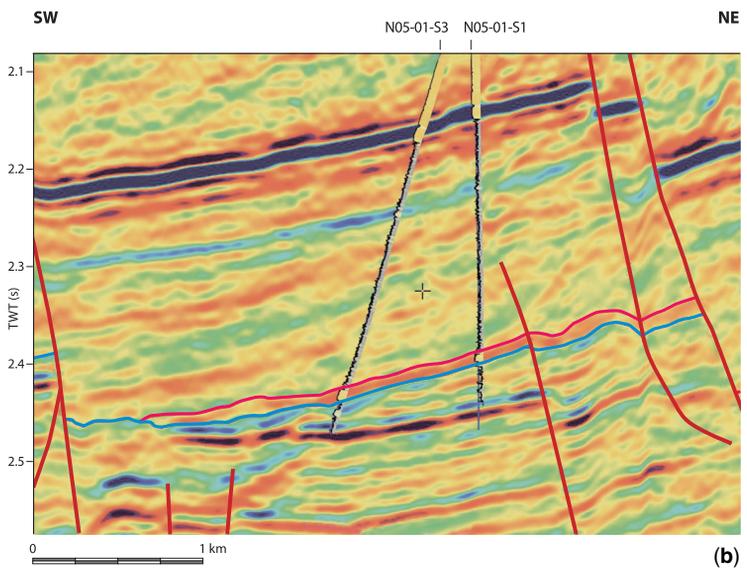
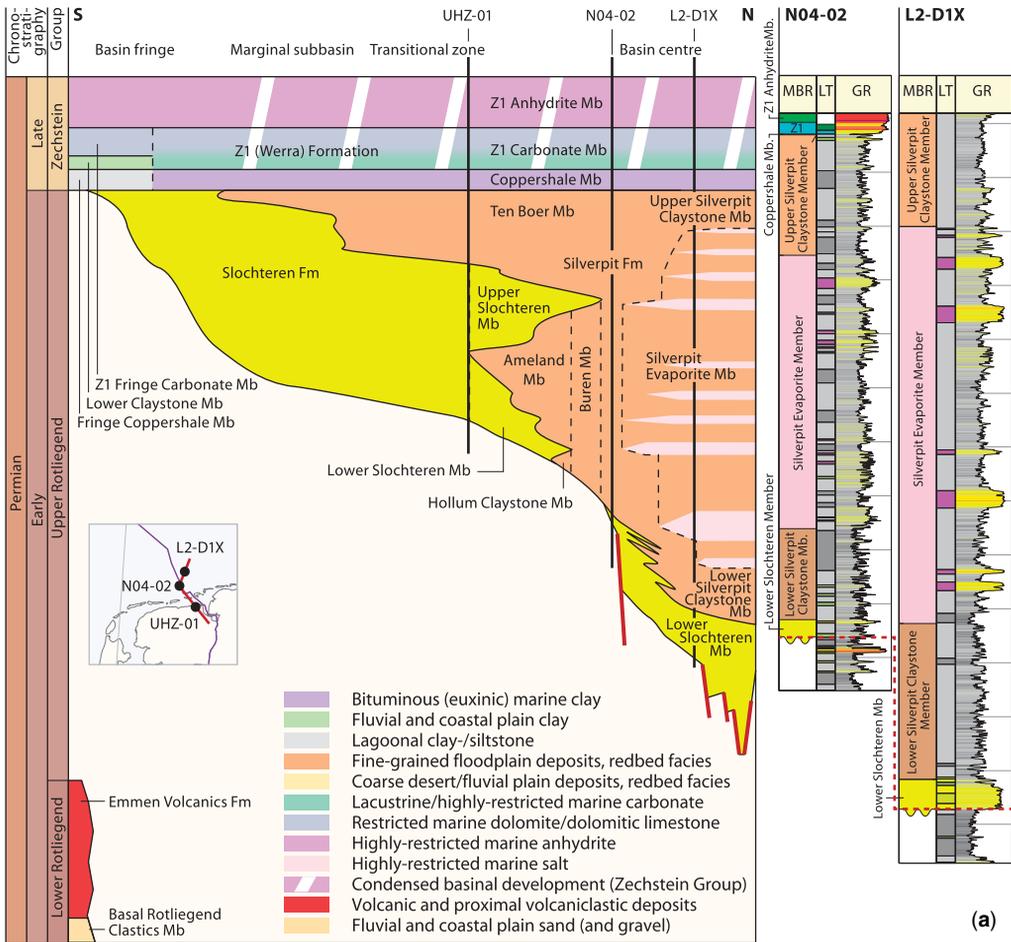
TNO (De Bruin *et al.* 2015) published on the Rotliegend palaeogeography along the northern fringe of the SPB in the Dutch offshore, postulating reservoir sands in the Upper Rotliegend (Fig. 7) but also in the Lower Rotliegend. This Lower Rotliegend play needs to be proven, but De Bruin *et al.* (2015) predict the presence of sand-rich Lower Rotliegend in the Dutch northern A, B and F blocks. Further development in both UK and Dutch sectors is awaited but will require further study and maturation of prospective structures.

Further geothermal development of Rotliegend aquifers will be limited to onshore the Netherlands owing to the requirement to use the relatively low-grade heat locally. The temperature of Rotliegend aquifers (<http://www.thermogis.nl>) is insufficient to allow direct high-temperature geothermal development for industrial use. The high transmissivity requirements for low-grade geothermal installations make it likely that only the most permeable aeolian facies will be prime targets for further exploration. In that sense geothermal exploration in the Rotliegend play differs from hydrocarbon exploration as it does not require the presence of seal or source but does require high transmissivity. This has driven exploration towards underexplored areas where the seal play element, necessary for hydrocarbon prospectivity, is missing, such as the area stretching from Haarlem–Amsterdam to Arnhem–Nijmegen. An exploration risk in the area is deteriorated reservoir potential owing to strong inversion.

Zechstein

History of exploration

The upper Permian Zechstein Group in the SPB contains up to seven evaporite cycles, five of which (Z1–Z5) are found in the UK and the Netherlands. Each of these cycles is assigned the rank of formation (Cameron 1993a; Van Adrichem Boogaert & Kouwe 1994b) and they are similar in their vertical organization. They consist of a succession of claystone, carbonate, anhydrite, halite and potash salts. The depositional thickness of the Zechstein increases



from less than 50 m near the southern fringe of the basin to over 1200 m in the northern Dutch offshore (Geluk 2007a). Near the southern fringe a sandy facies is developed (the Zechstein Fringe), which occurs in each of the cycles.

Hydrocarbons have been produced from Zechstein carbonate reservoirs in the SPB since the middle of the last century. These fields are situated along the western and southern fringes of the SPB, in the UK, the Netherlands, Germany and Poland. The very first hydrocarbons ever recovered from the Dutch subsurface were from Zechstein carbonates, with the exploration well Corle-01 that found oil as early as 1923. Commercial gas production from Zechstein carbonates started in the 1950s from onshore fields in the northeastern part of the Netherlands with NAM as operator. Most of these fields are also gas-bearing in Carboniferous reservoirs.

The first Dutch offshore Zechstein discovery was the Q07-A oil and gas field in 1962. In the UK, the first discovery that included Zechstein reservoirs was the Hewett Field. It was discovered in 1966 close to the UK mainland near Bacton, and produced from three reservoirs: the Bunter Sandstone, the Hewett Sandstone (uppermost Zechstein) and the Zechsteinkalk (Z1). The first discovery that contained hydrocarbons exclusively in the Zechstein became known as the Wissey Field. It was discovered in 1967 through well 53/04-1 and started production in 2008. Since this discovery, tens of oil and gas fields, both on and offshore, have been discovered and developed producing from Zechstein carbonates (Fig. 2).

Gas and oil from Zechstein reservoirs are mainly produced from either Z2 or Z3 carbonates, whilst the seal is provided by overlying salts. Exploration focus has traditionally been on the porous oolite belts within the Z2 and Z3 carbonates (Van der Baan 1990; Van de Sande *et al.* 1996), which run approximately east–west, parallel to the southern border of the basin. These oolite belts have good primary reservoir properties, which may be enhanced by diagenetic leaching and early charging (Van der Baan 1990). The highest production rates in gas field wells are attained through the presence of natural fractures. Towards the south of the basin, hydrocarbons are found in the sandy fringe facies too. The hydrocarbons originate from Zechstein basinal facies deposits, which contain type II source rock, and/or underlying Upper Carboniferous Westphalian coals, which contain type III source rock.

New discoveries since 2007

In the period 2007–17, five new discoveries have been made in the Zechstein, all located in the Netherlands (Fig. 2; Appendix A). Recoverable volumes are small, and typically less than 1 bcm per discovery. The new discoveries are the P11b-Van Nes (2007, Dana), De Hoeve (2010, Vermilion), Langezwaag (2011, Vermilion), Nieuwehorne (2011, Vermilion) and Zuidwijk (2012, TAQA) gas fields. From these fields, as of August 2018, only De Hoeve and Langezwaag are producing. Production from P11b-Nes has already ceased, and for the remaining two fields no production licence has been applied yet. All of these discoveries fall into the two traditional Zechstein plays. P11b-Van Nes produced from the Zechstein Fringe Sandstone, and the others from Z2 and Z3 carbonates.

Future trends

A number of papers have been published recently, drawing attention to hitherto overlooked targets for Zechstein hydrocarbon exploration (e.g. Mulholland *et al.* 2018; Grant *et al.* 2019). Around the Mid North Sea High, intra-Zechstein clinoform foresets represent an attractive exploration target (Patruno *et al.* 2018). Likewise, in a belt around the Elbow Spit High, the distribution of carbonates in the Z1 and Z2 cycles was revisited and a number of undrilled Zechstein platforms, probably build-ups, have been mapped (Fig. 8). A review of oil and gas shows and basin modelling suggests that the reservoirs could be charged from intra-Zechstein source rocks and from Lower Carboniferous coals. The presence of a large hiatus at the top Zechstein in this area suggests that collapse breccia and pipes, which are present at crop in England, may be present in the Mid North Sea High area too (Jaarsma *et al.* 2016). Furthermore, a number of stranded fields are waiting to be developed and taken into production. The Q07-A (now called Q10A) field started development in 2018, 56 years after discovery.

Triassic

History of exploration

In terms of recoverable hydrocarbon volume, the Triassic play is the second-most prolific hydrocarbon system in the SNSB area. The first Dutch Triassic discovery was made in 1948 when the onshore Coevorden Field was drilled in a tilted and faulted

Fig. 6. (a) Stratigraphic position of the new Lower Slochteren Member within the lowest Upper Rotliegend Group (after Burgess *et al.* 2018). (b) Seismic cross-section (freely available at <http://www.nlog.nl>) running SW (left) to NE (right) of the Ruby Field indicating the high acoustic impedance contrast associated with the reservoir sand units. Wells indicated are N05-01-S1 (right) and N05-01-S3 (left) both with gamma ray curve displayed. The top (red) and base (blue) reservoir intervals are interpreted.

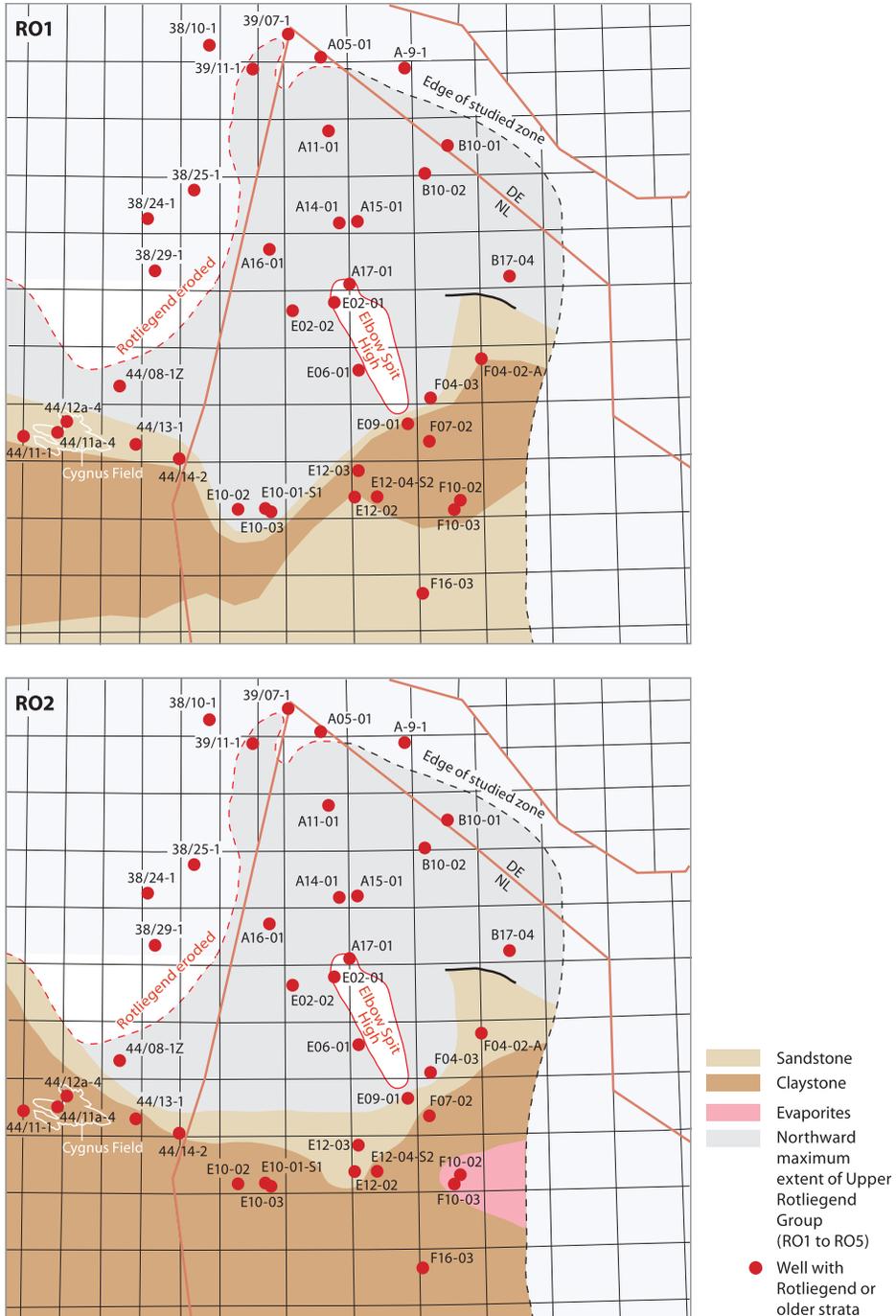


Fig. 7. Depositional maps for the first two (RO1 and RO2) out of five stratigraphic units (RO1–5) recognized in the Upper Rotliegend Group in the northern part of the Dutch offshore. In the southern part of the mapped area, stratigraphic units RO1 and RO2 are up to 28 and 105 m thick, respectively, and pinch out northward. Evaporite deposits are present in the upper part of RO2 and delineate the Silverpit lake axis in the southeastern part of the map. The erosional limit indicated in red corresponds to the Elbow Spit High. RO1 corresponds to the Cygnus Field reservoir sands in the UK sector and may be prospective in the Dutch sector. Modified from *De Bruin et al. (2015)*.

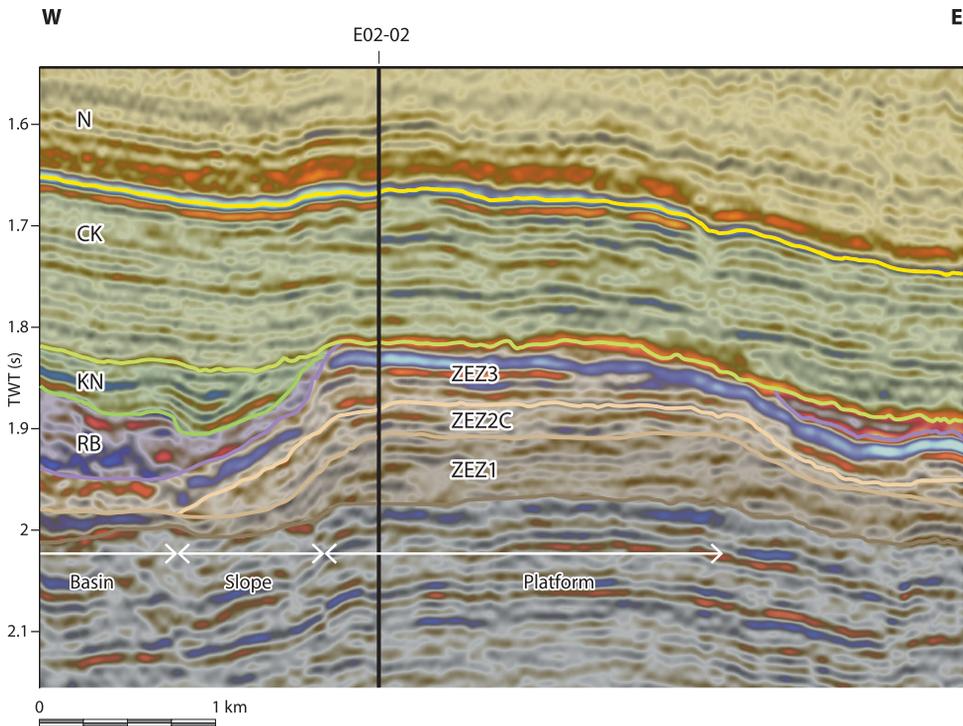


Fig. 8. West-east seismic line (freely available at <http://www.nlog.nl>) through well E02-02. The seismic and well data indicate that the well was drilled on a Z2 (Stassfurt) Formation carbonate build-up (Jaarsma *et al.* 2016). N, North Sea Supergroup (Cenozoic); CK, Chalk Group (Late Cretaceous); KN, Rijnland Group (Early Cretaceous); RB, Lower Germanic Trias Group; ZE, Zechstein Group (late Permian); ZEZ2C, Z2 Carbonate Member; ZEZ1A, Z1 Anhydrite Member.

structure, targeting a reservoir sequence composed of Muschelkalk, Röt, Detfurth and Volpriehausen formations (Bachmann *et al.* 2010). Although the Upper and Middle Triassic Muschelkalk, Keuper and Röt deposits are known to locally form reservoirs contributing to this play type (Bachmann *et al.* 2010), most Triassic reservoirs in the SNSB area consist of sandstones from the Main Buntsandstein Subgroup (Van Adrichem Boogaert & Kouwe 1994a). Regionally widespread mixed aeolian and fluvial sediments of the Lower Volpriehausen and Detfurth Sandstone members form the main reservoir intervals. Triassic deposits conformably rest on Permian deposits and their distribution follows the SPB geometry, later redefined by truncation and erosion during later tectonic phases. Reservoir quality may vary locally with, for example, the risk of salt-plugging of pore space when juxtaposed against salt bodies (Bachmann *et al.* 2010).

The primary hydrocarbon source rocks for Triassic gas fields are Westphalian and Namurian coals and organic-rich shales (e.g. Fontaine *et al.* 1993; De Jager & Geluk 2007; Ter Borgh *et al.* 2018). If Triassic reservoirs are juxtaposed against the oil-

prone Lower Jurassic Posidonia Shale Formation, they may be charged with oil (e.g. Pernis Field in the West Netherlands Basin) (De Jager *et al.* 1996).

Hydrocarbon migration can occur through windows where the Zechstein evaporites are absent or very thin and along major faults. Cenozoic volcanic dykes may also act as a conduit for hydrocarbons, even in areas where thick Zechstein evaporites are present. This has been described in the Forbes, Esmond, Gordon, Hunter and Caister Bunter fields in the UK (Underhill 2009).

Two main trap types can be described: (1) traps related to salt tectonics and associated faulting, such as salt-induced turtle-back anticlines; and (2) horst blocks where Zechstein salt is absent, e.g. in the West Netherlands Basin.

Discoveries since 2007

Triassic discoveries made in the 2007–17 period are displayed in Figure 2 and are all located in the Dutch part of the study area (Appendix A). Most discoveries are made in horst blocks and inverted flower structures in the West Netherlands Basin, in areas

where the level of Late Cretaceous and Early Cenozoic inversion tectonic activity has been limited and where reservoir quality is sufficiently high. In addition, several discoveries were made in the Terschelling and Vlieland basins and on the Schill Grund Platform in traps related to halokinesis. Successful follow-up of earlier discoveries in the Solling Formation (De Jager 2012), the so-called Fat Sand, has not been realized.

Only one geothermal system extracting energy from Triassic reservoirs (Main Buntsandstein Subgroup) is operational in the Netherlands (Vierpolders, see Fig. 2 and Appendix B). Depth and structural configuration, close to the line of truncation of the reservoir under the Base Cretaceous Unconformity and related reservoir quality enhancement, favour a productive Triassic at this location. The deeper Triassic exploration target of the Trias–Westland well (*c.* 3900 m; ref <http://www.nlog.nl>, well NLW-GT-01) has proven that deeper buried siliciclastic reservoirs may be exposed to burial diagenesis and associated permeability reduction, making similarly deep geothermal reservoirs higher-risk ventures.

Future trends and developments

It is generally perceived that the sediments constituting Lower Triassic reservoir rocks are sourced from the southern Variscan mountain belt, and that consequently reservoir presence and quality decrease towards the north (e.g. Geluk & Röhlings 1997; Geluk 2005, 2007b; Bachmann *et al.* 2010). However, Kortekaas *et al.* (2018) described the presence of reservoir sands in the northern Dutch offshore, north of the main southern sourced fairway. In the North German Basin, locally sourced fluvial sediments from the Ringkøbing–Fyn High were observed alternating with southerly sourced aeolian sands (Olivarius *et al.* 2017). Based on well and seismic analysis, Kortekaas *et al.* (2018) suggest the local presence of Early Triassic depocentres in the Step Graben area, west of the Dutch Central Graben. The location, lithological character and stratigraphic extent of these northern Triassic depocentres may suggest a northerly provenance for potential reservoir sands (Kortekaas *et al.* 2018). In the UK sector, the saline aquifer parts of the Triassic Bunter Sandstone Formation also provide significant storage potential (Bentham *et al.* 2014) in large anticlinal structures formed by post-depositional halokinesis in underlying Zechstein Group strata (Furnival *et al.* 2014; Williams *et al.* 2014). The potential for re-using oil and gas infrastructure such as pipelines, platforms and wells is of current interest for reducing costs associated with establishing new business models for the transport and storage of CO₂ (CCUS-CCTR 2018).

The presence of mature Carboniferous source rocks and a viable migration fairway for

hydrocarbons is often identified as a key risk for the Main Buntsandstein play in the northern Dutch offshore. A recent study by Ter Borgh *et al.* (2018), however, provides a different view of the source-rock presence and potential in the northern Dutch offshore area, where both Namurian shales and coals and Lower Carboniferous coals from the Elleboog (Visean) and Yoredale (Dinantian) formations are interpreted to be preserved and currently in the gas generation window (Schroot *et al.* 2006; De Bruin *et al.* 2015; Arfai & Lutz 2018; Ter Borgh *et al.* 2018). This provides a potential extension of the play into the northern Dutch offshore.

Migration of hydrocarbons from the Carboniferous into the overburden may occur along faults and fractures, through salt windows, along carrier beds and via volcanic dykes (Underhill 2009). The latter have been mapped in detail in the UK area, and have recently also been recognized and mapped in the Dutch subsurface (Kortekaas *et al.* 2018). These dykes may provide a path for hydrocarbon migration similar to analogue fields in the UK where the presence of gas has been proven (e.g. Caisster Bunter Field; Bachmann *et al.* 2010). However, migration is still considered the principal risk as a major seal (Zechstein) occurs between the source (Carboniferous) and Triassic reservoir rocks.

Within the Dutch Central Graben, the Triassic is often associated with high overpressures. Although overpressures do increase the risk of seal breach and pressure-limited hydrocarbon column lengths, higher reservoir pressures also result in higher initial volume of natural gas in a field (GIIP), while possibly the (early) arrest of compaction may have preserved porosity.

To summarize, the Lower Triassic sediments north of the main fairway may contain overlooked economic resources with the potential presence of reservoir sands sourced from the north, structural traps around complex salt bodies and the presence of mature Lower Carboniferous source rocks in addition to the commonly considered Westphalian coaly source rocks, and potential migration pathways along volcanic dykes.

Jurassic–Lower Cretaceous

History of exploration and petroleum geological setting

Lower Jurassic to Lower Cretaceous successions in the study area comprise numerous oil and gas fields (Fig. 3). In the UK sector, these fields are located exclusively onshore whilst in the Netherlands they occur both offshore and onshore.

In the UK, Middle and Upper Jurassic shallow-marine, ooidal and bioclastic limestones and

associated sandstones provide the reservoir for the hydrocarbon plays in the Wessex–Weald basins (Fig. 3, see e.g. Lott *et al.* 2010). The Great Oolite Group limestone is the main proven reservoir and is typically 45–60 m thick. Organic-rich mudstones and ‘oil-shales’ from the Lower Jurassic, Oxford Clay and Kimmeridge Clay formations form the principal source rocks. The main seals are Oxfordian and Kimmeridgian mudstones and Lower Cretaceous evaporites (Lott *et al.* 2010).

In the Netherlands, Jurassic–Lower Cretaceous plays are principally restricted to Cimmerian rift basins such as the Dutch Central Graben, the Terschelling Basin, the Vlieland Basin and the Broad Fourteens Basin. Onshore, the West and Central Netherlands basins and Lower Saxony Basin comprise a significant number of oil and gas fields (De Jager & Geluk 2007). The reservoirs occur in clastic syn-rift and early post-rift deposits, which show rapid facies variations ranging from continental to marine. The majority of discoveries are found in shallow-marine sandstone reservoir facies. Most of the onshore Upper Jurassic–Lower Cretaceous fields contain oil since they are charged from the high TOC type II claystones of the marine Lower Jurassic Posidonia Shale Formation.

New discoveries since 2007

Both in the UK and in the Netherlands, two discoveries were made (Fig. 3 and Appendix A). In the UK, the Horsehill and Markwells Wood discoveries are in conventional Portland Group formations and in Great Oolite Group limestone reservoirs, sourced from Lower and Upper Jurassic (Kimmeridge Clay Formation) source rocks. In the Netherlands, the small Vinkega discovery encountered a gas-bearing Lower Cretaceous Vlieland Sandstone Formation reservoir. A more significant discovery in the Netherlands is that of the M07-B gas field. This Lower Cretaceous gas field was discovered in 2007 and is located along the southern margin of the Terschelling Basin in a complex setting that involves syn-tectonic deposition and local sediment erosion and re-deposition. Initially, reservoir properties were considered poor, which hampered development. This changed in 2013 when well M07-07 was drilled and found good reservoir properties and gas shows. This led to the development of the field and the M07-A platform started production in September 2013. An additional well (M07-08) was drilled in 2014.

New insights

A substantial increase in the understanding of the Dutch Lower Jurassic to Lower Cretaceous source- and reservoir-rock types, facies, architectures and distribution has been gathered as a result of

ongoing research, converging in a better understanding of the complex tectonostratigraphy that involved both active rifting and salt tectonics. This new knowledge has been established by increasingly firm biostratigraphic control resulting from Joint Industry Projects (e.g. Houben *et al.* 2017). These tectonostratigraphic concepts are outlined in two recent publications (Bouroullec *et al.* 2018; Verreussel *et al.* 2018).

Recent studies focusing on Lower Jurassic source rocks (Nelskamp *et al.* 2015; Houben *et al.* 2017) have shown that the Posidonia Shale Formation is temporally confined to the relatively short-lived (500 kyr) Toarcian Oceanic Anoxic Event (Hesselbo *et al.* 2000). It represents an isolated interval of enhanced runoff, with surface-water stagnation collectively leading to enrichment of hydrogen-rich organic matter, in an otherwise rather homogeneous and organic-lean Lower Jurassic sequence (Houben *et al.* 2017). In addition to the Westphalian as the prime gas source, the Upper Jurassic coal-bearing sequences, such as those of the Oxfordian Lower and Middle Graben formations (Verreussel *et al.* 2018), may also provide gas-prone source rocks.

For the reservoir intervals confined to the Middle Jurassic to Early Cretaceous, four Middle Jurassic–Early Cretaceous tectonostratigraphic mega-sequences (TMS-1 to -4, see Verreussel *et al.* 2018 and Fig. 9) are recognized in the Dutch, German and Danish offshore area (Munsterman *et al.* 2012; Bouroullec *et al.* 2018; Verreussel *et al.* 2018). These mega-sequences reflect four main stages of basin evolution for the Central Graben and its adjacent sub-basins and platforms. In the Dutch Central Graben, up to 1500 m of fluvio-lacustrine and shallow-marine sequences (TMS-1; Fig. 9) accumulated. Adjacent highs, such as the Step Graben, Friesland and Schill Grund platforms, were uplifted and eroded. The Terschelling Basin became a sediment catchment area during the Kimmeridgian to Ryazanian periods (depositional time of TMS-2 and 3). Sediments of TMS-2 and 3 were also deposited in the Dutch Central Graben and accumulated only as thin intervals on the surrounding platforms (Munsterman *et al.* 2012). Contemporaneously to an end-Ryazanian transgression, rifting ceased with the region subsequently undergoing post-rift sag. This broadened the area of sediment accumulation to the entire North Sea (Cromer Knoll Formation in UK and Norwegian sectors; see Verreussel *et al.* 2018). The sediments of this interval (TMS-4, Fig. 9) are generally mud-prone, but close inspection reveals thin sandy deposits at the base of the Cretaceous transgression (e.g. Vlieland Sandstone Formation on the Schill Grund Platform and Vlieland Basin; Duin *et al.* 2006; Jeremiah *et al.* 2010; Munsterman *et al.* 2012). In the Dutch sector, the sequences contain sand-rich reservoir intervals such as the Lower,

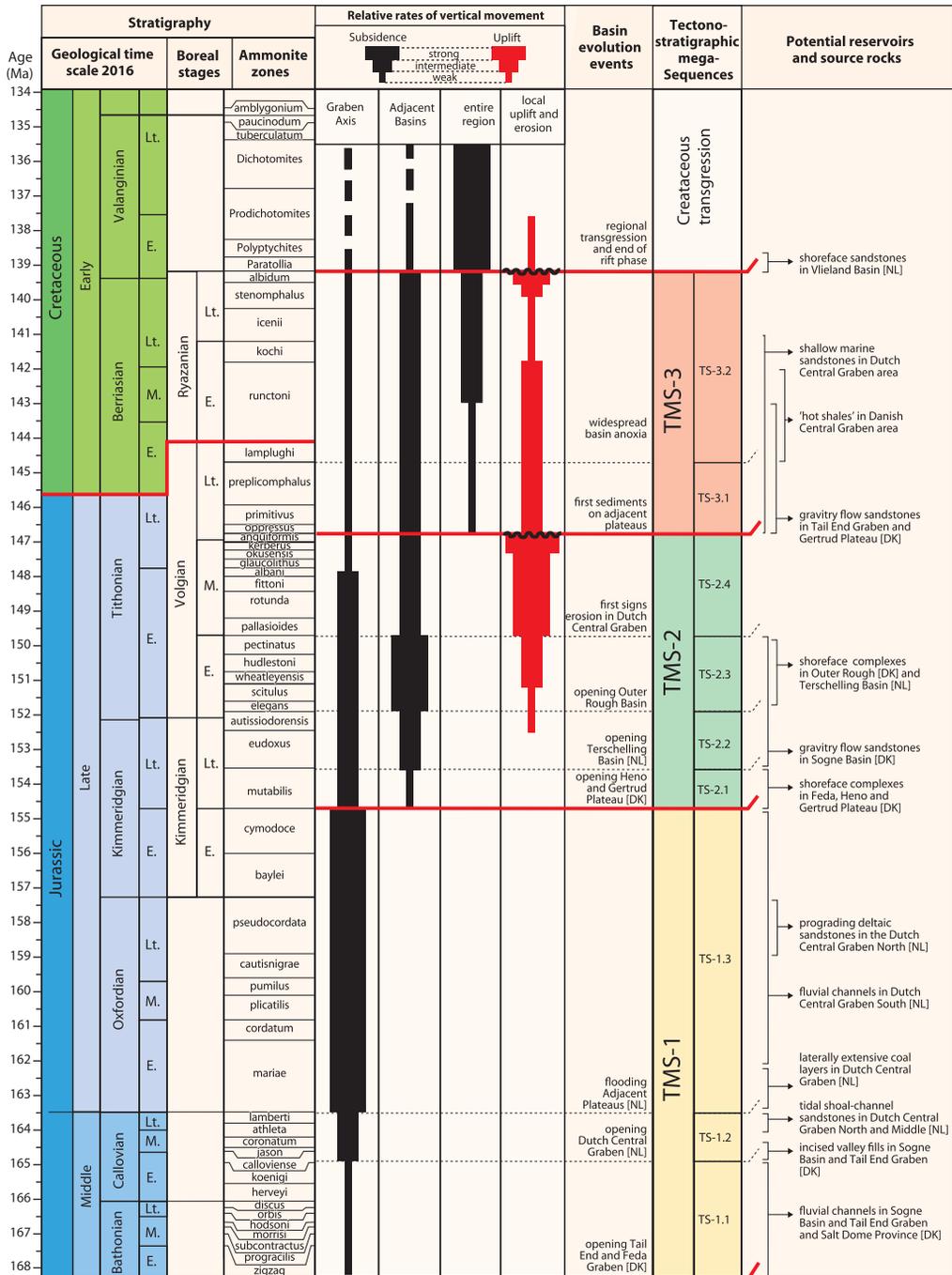


Fig. 9. Schematic representation of the stepwise basin evolution of the Middle Jurassic to Early Cretaceous in the Southern North Sea Basin (SNSB) area. The vertical black bars represent the relative amount of basin subsidence for the different structural domains. These are estimated from the thicknesses of the sedimentary successions. Figure is adapted from Verreussel *et al.* (2018).

Middle and Upper Graben and the Friese Front formations (TMS-1), the Terschelling Sandstone and the Noordsvaarder members (TMS-2) and the Scruff Greensand Formation (TMS-3) (Fig. 9).

Future trends and developments

With improved understanding of the tectonostratigraphy of the Middle Jurassic–Early Cretaceous in the Dutch offshore, new insights are offered on the complex interplay between active structures and depositional systems. This may lead to the identification of potential new play types along the rift basin margins and along-basin axis, and in settings affected by salt tectonics. New plays may include combined stratigraphic/structural traps along sediment pathways carrying sediments from the platform areas to the rift basins, possibly with an element of syn-depositional halokinesis.

Geothermal development drilling in the period 2007–17 resulted in 11 geothermal systems in the Netherlands exploiting the Upper Jurassic–Lower Cretaceous sedimentary sequence (Fig. 3 and Appendix B). Following on from hydrocarbon exploration experience, the Vlieland Sandstone Formation of the Rijnland Group was the primary target initially, with the deeper Schieland Group being a secondary target. However, geothermal wells drilled in synclines, contrary to anticlinal conventional oil and gas wells, found that the Schieland Group sandstones in the lows are thicker and have higher permeabilities than the pre-drill expectation (Willems *et al.* 2017; Vondrak *et al.* 2018). Presently, the Schieland Group sandstones, especially the Delft Sandstone Member, are the primary target for geothermal exploration with better reservoir characteristics and hotter than the overlying Vlieland Sandstone Formation sandstones.

Upper Cretaceous

This section focuses only on the Dutch sector of the study area, as there are no recent Chalk exploration activities in the UK. This is probably due to the absence of Lower Jurassic source rocks in the UK part of the SNSB area (Lott *et al.* 2010, fig. 10.12). The Chalk Group in the Netherlands includes the Upper Cretaceous Texel and Ommelanden formations and the Danian Ekofisk Formation. Although the Chalk Group is present in large parts of the study area, the number of oil and gas fields reser-voired in the Chalk is limited (Fig. 3). This is mainly related to migration problems for hydrocarbons originating from Carboniferous or Jurassic source rocks (Henk van Lochem, pers. comm.). The upper Maas-trichtian and Danian part of the Chalk Group generally has suitable properties for oil and gas reservoirs

with fractures being an important element to make this play work.

History of exploration

Numerous Chalk fields in the North Sea have been brought to production since the late 1960s, such as the Norwegian Ekofisk and the Danish Halfdan and Sif fields and the UK Machar and Banff oil fields. In the onshore Netherlands, the first Chalk discovery was with well HRL-01 drilled in 1965 by Elf-Petroland. Well HRL-02 was drilled shortly afterwards and also found gas in the Ommelanden Formation. The gas accumulation is known as the Harlingen Upper Cretaceous Field, with a GIIP of 3 bcm. The field is currently owned by Vermilion and production has ceased owing to production-induced subsidence.

The first offshore Chalk discovery was made in 1972 by Wintershall above the Triassic K13-A gas field (well K13-01). After depletion of the Triassic gas field, perforation of one of the nine production wells proved a gas accumulation in the Ommelanden Formation. Subsequently, well K13-A-10 was drilled in 1991 and the accumulation was tested. The test demonstrated that the accumulation was too small to be produced (Henk van Lochem, pers. comm.).

The first oil field in the Chalk (the F02 Hanze oil field) was discovered by RWE-DEA in 1996 (well F02-05). At the time, it was the southernmost oil discovery in the Chalk in the North Sea (Dominik *et al.* 2000). The oil field has been producing since 2001 and is now operated by Dana Petroleum. The field is the largest producing offshore oil field in the Netherlands with an initial volume of oil in a field (STOIIP) of $20.5 \times 10^6 \text{ m}^3$ (<https://www.nlog.nl>, production plan). The originally overpressured oil field is sourced from the Jurassic Posidonia Shale Formation and the reservoir consists of fractured carbonates of the upper part of the Ommelanden Formation and the Ekofisk Formation located on top of a strongly uplifted salt diapir (Dana-Petroleum 2014).

New discoveries, exploration activities and insights since 2007

A number of studies were initiated after the discovery of the Hanze oil field, including the sedimentary and seismic-stratigraphic studies of Van der Molen (2004) and Van der Molen *et al.* (2005) and the integrated studies regarding key conditions for successful Chalk plays (Guasti *et al.* 2009, 2010; Verweij *et al.* 2009). Following these promising studies, new exploration initiatives by Wintershall, Dana and Total have resulted in new oil finds in the Dutch offshore. Wintershall started the Chalk boom by the successful discovery well F17-10 in 2012, followed by wells F17-11 to F17-14. The

fields F17-NE (Rembrandt) and F17-SW Culmination (also known as Vermeer) (Fig. 3 and Appendix A) are not producing yet. Several hundred metres of core were taken and studied in detail (Van Lochem 2018). In 2014, a broadband 3D seismic survey was acquired to better image the discoveries.

Wintershall's discovery triggered Dana Petroleum to further explore the Chalk. After the observation of oil shows in the Chalk between 1447 and 1482 m along hole depth (AHD) in well F06-02 (1992) by Elf-Petroland, Dana drilled two wells in 2014 (F06-05 and F06-06 with three sidetracks) leading to the discovery of the F06b-Zulu North Field and the F06b-Snellius Field (Fig. 3 and Appendix A). To date, the precise stratigraphic interval containing the oil has not been made public. In 2015, Total's exploration well F12-05 proved dry.

A new Chalk play in the North Sea. The discoveries made by Wintershall in the F17 block represent an extension of the Chalk play known from the Central North Sea and the Hanze discovery in the northern Dutch sector. Late Cretaceous inversion tectonics, which resulted in an elongated and subaerially exposed anticline parallel to the axis of the Dutch Central Graben, is key to this play. Above this sub-Hercynian unconformity a thin veneer (generally <100 m) of Maastrichtian Chalk was deposited. In the F17 area (Fig. 3, fields 92 and 95), the porosity of the Maastrichtian Chalk increases from 25% near the base to 38% near the top of the succession, proportionally with a decrease in siliciclastic and skeletal grains. This Chalk unit is underlain by a conglomeratic- and siliciclastic-rich interval, which is itself underlain by a sandstone interval found in several wells. The base of the sandstone represents the (Late Cretaceous) Sub-Hercynian unconformity.

The oil is hosted within the porous upper part of the Maastrichtian Chalk and sealed by the overlying clays of the Paleocene Landen Formation. Analogous to the Hanze Field, the oil in the Rembrandt and Vermeer fields is trapped in an anticlinal structure above a Zechstein salt diapir (Van Lochem 2018). The Chalk is 40–80 m thick above the salt diapir and only 20–30 m on its flanks. The greater thickness above the salt diapir may be explained by subsidence of the underlying salt leading to channel incisions on the flanks of the structure, which would be consistent with the presence of Campanian sandstones at the base of the Chalk Group (Van Lochem 2018).

Future trends and developments

The recent exploration successes in the Chalk play, such as those proven by the F17 discoveries, may lead to further new oil and gas finds. Favourable Chalk reservoir characteristics are also suggested

by recent observations of total losses of mud, reported at 945 m AHD in the Texel Marlstone Member while drilling onshore geothermal well PNA-GT-03-Sidetrack-2. The mud losses suggest a (local) zone of high permeability. Interpretation of a seismic survey in the Dutch offshore P15-block (Z3AMC1989A) has recognized features that resemble intra-Chalk runoff channels (Fig. 10). The channels occur relatively regularly about every 1000–1500 m, are oriented NE–SW and may be related to uplift occurring to the NE, as suggested by the widening of the channels towards the SW. The infill of the channels is unknown, but may host stratigraphic traps. For further developments in research on the Chalk, the reader is referred to Van der Voet *et al.* (2018), Deckers & Van der Voet (2018) and Smit (2018).

Cenozoic

History of exploration

Cenozoic sediments in the Dutch, UK and German North Sea sectors host abundant seismic-amplitude anomalies (bright spots, flat spots, velocity pull-down, attenuation, phase reversals), of which several are proven to be related to shallow gas accumulations. In all countries, increasing attention is given to shallow gas, as an energy resource or a possible geohazard for drilling and wind farm positioning, or to assess the effects of seabed gas emissions on marine ecosystems and climate (Verweij *et al.* 2018). The Netherlands was the first country in the North Sea region in which these accumulations have been developed as an energy resource.

Bright spots were already detected in the early 1970s, but in the late 1980s and 1990s several boreholes encountered shallow gas whilst drilling through Plio-Pleistocene shelf-edge delta deposits (SNS delta) (e.g. A12-03, A15-02, A18-02, A18-02-S1, B10-03, B13-03, B16-01, B17-05, B17-06, F02-05) (Fig. 11). Well A18-02 is recognized as the first discovery of shallow gas in an economically producible quantity. An inventory of bright spots on seismic data showed that many of the potential gas accumulations reside in shallow-marine to continental (deltaic) deposits of the Plio-Pleistocene SNS delta. The gas is either structurally trapped in anticlines above salt domes (e.g. Fig. 11) or associated with lateral fault seals, or occurs in stratigraphic or depositional traps (Schroot & Schüttenhelm 2003; Schroot *et al.* 2005; Kuhlmann & Wong 2008; Kombrink *et al.* 2012; Van den Boogaard & Hoetz 2012; Ten Veen *et al.* 2013, 2014; Williams & Gent 2015). Van den Boogaard *et al.* (2013) presented a preliminary total volume estimate for the shallow gas play in the Dutch North Sea sector of 36–118 bcm GHP. Geochemical and carbon isotopic

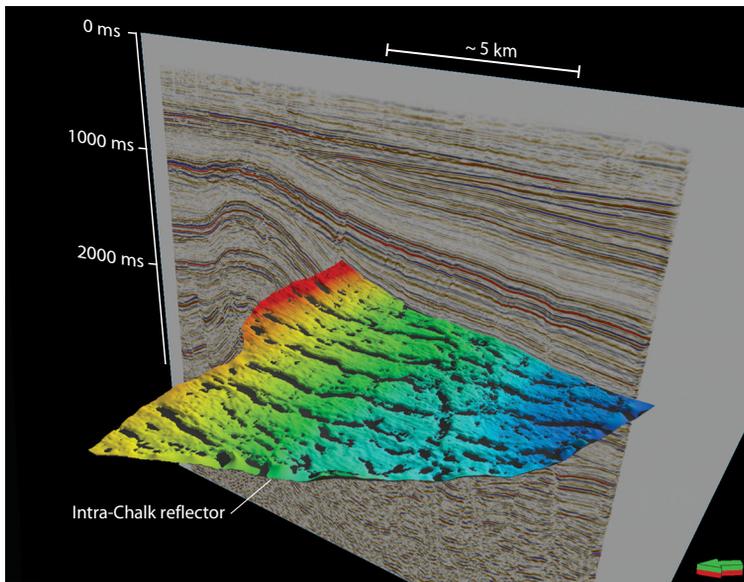


Fig. 10. Intra-Chalk Group runoff channels as observed in seismic survey Z3AMC1989A, block P15, Dutch offshore (freely available at <http://www.nlog.nl>). Arrow points towards the north. Channel interspacing is 1000–1500 m.

compositions of shallow gas accumulations in the SNS delta obtained from eight wells (A12-03, A18-02, B10-03, B13-03, B13-04, B16-01, B17-05 and F01-01) show that at these locations gas is very dry and has a microbial signature (Verweij *et al.* 2018).

Appraisal well A15-03 drilled in 1999 by Winterhall proved essential for an enhanced understanding of the geology of the shallow gas reservoirs and has been extensively studied. For instance, Kuhlmann & Wong (2008) linked the occurrence of gas to specific delta subenvironments and stratigraphic intervals that are controlled by Late Cenozoic glaciations (see also Donders *et al.* 2018). The study by Kuhlmann & Wong (2008) was instrumental in illustrating the importance of a sound understanding of the regional extent and architectural characteristics of the shelf delta for exploration and production. Stuart & Huuse (2012) made palaeogeographic reconstructions of the epicontinental North Sea Basin and elucidated the role of hypothesized tidally generated contour currents that led to the formation of sandy contourites, now identifiable by ‘bright spots’ on seismic data.

Initially, shallow gas fields (Fig. 3) were considered uneconomic and too challenging to develop for technical reasons. With the limited strength of the unconsolidated sandy reservoirs, early water breakthrough and sand production were expected (Van den Boogaard & Hoetz 2012). The field inventory for the SPB Atlas (Doornbal & Stevenson 2010) dates back to 2007 and mentions a total of six fields

that were expected to become developed. Eventually in 2007, almost 30 years after borehole A12-03 encountered gas, the shallow gas A12-FA Field (Fig. 11) was the first to be taken into production by Chevron (now Petrogas). This field was by then amongst the best producing gas fields in the country with a peak production rate of 3×10^6 m³/day via six producers. The economics of shallow gas has improved over the years owing to the advance of horizontal drilling techniques, the ability to separate sand through an expandable sand screen and the use of simple satellite platforms that connect with nearby processing platforms (e.g. the A12 platform) that can also deliver the required compression and access to the gas network.

New insights and discoveries since 2007

The F02 Pliocene field (also called HANP Field) is a new shallow gas discovery above the Hanze oil field that was brought into production in 2009 by Dana Petroleum. Subsequently, Petrogas started production of field B13-FA in 2011 and field A18-FA in January 2016 (almost 40 years after discovery). The four producing shallow gas fields show a steady contribution amounting to c. 1 bcm per year. The expected development of A15-A, B10-A, and B16A (licence withdrawn) proved uneconomic.

Just north of the Mid North Sea High (Fig. 2), Simwell was awarded exploration licences in UK block 29/22b, 23b, 27, 28 during the 2018 29th

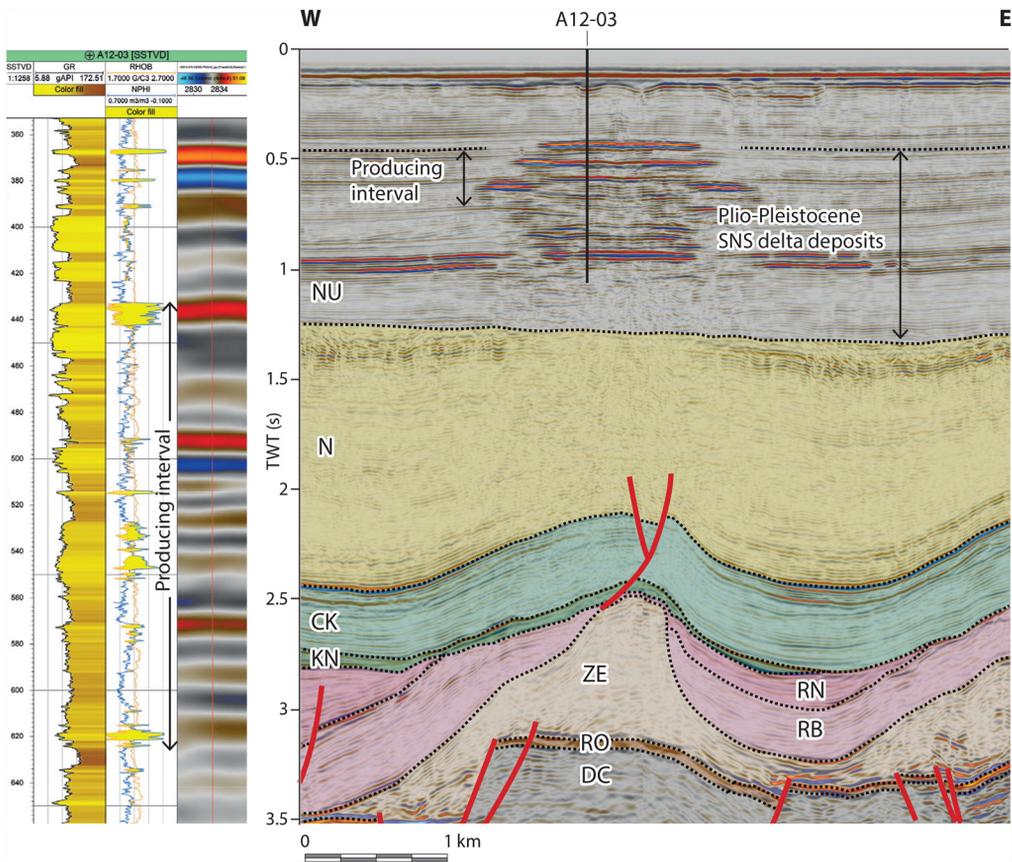


Fig. 11. Left: well logs of well A12-03 (GR, NPHI-RHOB cross-over plot indicating gas-filled sands and seismic extraction around the well path). Right: west-east seismic section across the A12-FA field showing stacked bright spots in the Southern North Sea (SNS) delta deposits of Plio-Pleistocene age. Note that the vertical scales for the well logs and seismic section are not the same. The bright spots in the producing interval correspond with gas-bearing sand as highlighted by the NPHI-RHOB cross-over plot to the left. The multilayer gas field is in a gentle anticline above a Zechstein salt dome. NU, Upper North Sea Group (Neogene + Quaternary); N, Lower and Middle North Sea groups (Paleogene); CK, Chalk Group (Late Cretaceous); KN, Rijnland Group (Early Cretaceous); RN, Upper Germanic Trias Group; RB, Lower Germanic Trias Group; ZE, Zechstein Group (late Permian); RO, Upper Rotliegend Group (late Permian); DC, Limburg Group (Carboniferous). Vertical exaggeration: approximately $\times 2$.

UK Offshore Licensing Round. The company identified two leads with stacked reservoirs, analogues to the Dutch reservoirs, based on the presence of bright spots and four-way dip closures with an estimated mean (P50) GIIP of 34 bcm.

Future trends and developments

No new exploration licences have recently been applied for. However, research is still being carried out in order to assess critical factors such as the origin of the gas, estimating gas saturations prior to drilling and cost reduction. A newly acquired 3D seismic survey in 2012 by Fugro that covers the Dutch Central Graben in the D, E and F blocks

may lead to the discovery of more and larger bright spots and associated gas accumulations as the area was previously predominantly covered by 2D seismic lines. For the remainder of the northern offshore, it is not expected that major future discoveries will be made as most gas accumulations have been identified.

Onshore, Cenozoic sediments can also be used to buffer geothermal and seasonal heat. Although all oil and gas wells are drilled through the Cenozoic interval, detailed reservoir knowledge is limited by the fact that data acquisition (logging) for this interval is minimal. Reservoir delineation and characterization studies are scarce, hampering the development of the Cenozoic for other energy resources. To

date, in the Netherlands the Cenozoic interval is mostly used for 'health spa' purposes (Lokhorst & Wong 2007), although currently a low-temperature (30°C) geothermal system for greenhouse heating is being installed in the Eocene Brussels Sand Member near Zevenbergen in the SW of the Netherlands.

Discussion and conclusions

The development in energy resources of the SNSB area is discussed in the following sections, including past, recent (2007–17) and future developments.

Historical developments

In both the UK and in the Netherlands, the pre-Groningen (1959) era of hydrocarbon exploration focused on a variety of geological formations with the Rotliegend generally being overlooked. In the UK, the East Midlands proved to be an area with relatively small hydrocarbon accumulations in the Carboniferous (e.g. Eakring oil field ($0.79 \times 10^6 \text{ m}^3$), 1939), whilst in the Weald Basin several Jurassic formations turned out to be prospective. In the Netherlands, during the first decennia of exploration, there was a widespread belief that the Zechstein Kupferschiefer was the main source rock. This was the result of some discoveries in the Zechstein, the first oil being found in 1923 near Corle close to the German border (0.24 m^3). The largest and most important oil discovery in the Netherlands took place in 1944 when oil was found in the Lower Cretaceous reservoir of the Schoonebeek Field in the east of the country with an oil initially-in-place of $c. 163 \times 10^6 \text{ m}^3$. This field is still producing today (Fig. 12a). Further exploration led to the discovery of nearby oil and gas reservoirs in Upper Jurassic/Lower Cretaceous intervals (e.g. Zweelo), but also in Upper Carboniferous, Zechstein and Triassic formations (e.g. Coevorden, De Wijk, Wanneperveen, Tubbergen).

Exploration histories for the Netherlands and UK are shown in two separate creaming curves in Figure 12a & b. The cumulative amounts of oil and gas discovered onshore and offshore per stratigraphic unit are given in units of energy (PJ). The corresponding total energy, and Groningen equivalent gas volumes (Geq.), discovered before and after 2007 for the UK and the Netherlands (small fields and Groningen Field) are presented in Table 1.

The most important discovery in the Rotliegend took place in 1959, when the giant Groningen gas field in the northeastern part of the Netherlands was found (2900 bcm). This was followed by other relevant Rotliegend discoveries with significant ultimate recoveries (UR) such as Annerveen (76 bcm) and Ameland-East (59 bcm) (Fig. 12a). In the UK, the discovery of the Groningen Field fostered an increase in the offshore exploration activity in the Upper Rotliegend Group throughout the 1960s. This activity led

to the discovery in 1966 of the Leman Field, the UK's largest offshore gas field with an initial-gas-in-place estimated around 316 bcm (Fig. 12b). Other important Rotliegend fields are Viking (UR 90 bcm), Indefatigable (UR 81 bcm), West Sole (UR 59 bcm) and Ravenspurn (UR 45 bcm). In the Netherlands, the onset of significant exploration efforts onshore and offshore took place a little later in the mid-1970s, as a result of the implementation of the small-field policy following the oil crisis of 1974. This policy was established to give preferential treatment to the discovery and production of other oil/gas fields than the Groningen Field (Mulder & Zwart 2006). Acquisition of seismic data aided the success of exploration campaigns. Although important 2D seismic acquisition took place from 1960 until the 1980s, the improved technology of 3D seismic, acquired in main parts of the SPB area, led to numerous and significant discoveries in the 1980s and 1990s (Fig. 12).

In addition to the Rotliegend discoveries, Carboniferous formations proved to be the most prolific natural gas reservoirs in the UK (e.g. Murdoch (UR 13 bcm), Schooner (UR 9 bcm)), with some Triassic and Zechstein accumulations (e.g. Hewett (UR 122 bcm), Esmond (UR 9 bcm), Orwell (UR 9 bcm)) (Fig. 12b). In the Netherlands, the Triassic was the most successful natural gas reservoir after the Rotliegend (e.g. Roswinkel (UR 15 bcm), De Wijk (UR 21 bcm), L09-FD (UR 25 bcm)), but also the Upper Carboniferous (e.g. E17-FA (UR 3 bcm), K04-A (UR 9 bcm), Coevorden (UR 36 bcm Carb + Ze)) and Zechstein (e.g. Schoonebeek-gas (UR 10 bcm)), which contributed with significant volumes (Fig. 12a). Oil, on the other hand, was mainly found in Lower Cretaceous formations in some discoveries made offshore and onshore in the 1980s (e.g. Horizon (UR $3 \times 10^6 \text{ m}^3$), P15-Rijn (UR $4 \times 10^6 \text{ m}^3$), Kotter (UR $12 \times 10^6 \text{ m}^3$), Rotterdam (UR $15 \times 10^6 \text{ m}^3$)). Since the 1990s, discoveries continued to take place in all main age intervals in the SNSB area. Shallow gas fields from Cenozoic formations saw the start of significant exploration during the 1990s (Fig. 12a), which are almost exclusively found in the northern part of the Dutch Central Graben.

Recent developments 2007–17

Between 2007 and 2017, natural gas is the main hydrocarbon type in most of the newly discovered fields in the SNSB area. The reservoirs range from Rotliegend (50), Triassic (21), Upper Carboniferous (12), Zechstein (5) and Upper Jurassic/Lower Cretaceous (1) intervals (Fig. 2 and Appendix A). In seven discoveries of Upper Cretaceous (4), Jurassic (2) and Triassic (1) age oil was the primary fluid type (Fig. 3 and Appendix A).

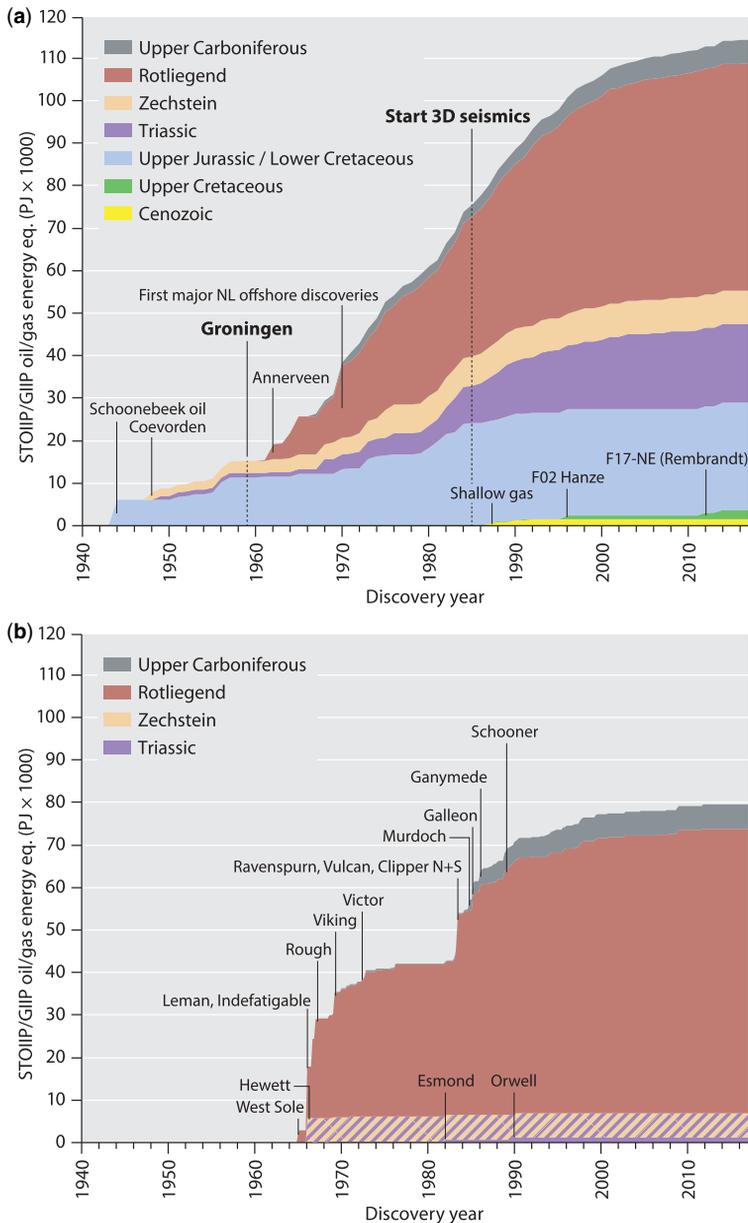


Fig. 12. (a) Creaming curve based on the oil (STOIIP) and gas (GIIP) resources v. year of discovery per lithostratigraphic unit found in the onshore and offshore areas of the Netherlands. The resources of gas discovered in 1959 in the Groningen Field (Rotliegend) were not included in this figure in view of its large magnitude (GIIP: c. 2900 bcm ($35.17 \text{ MJ m}^{-3} \rightarrow \text{energy eq. c. } 102 \times 10^3 \text{ PJ}$)). Volumes of oil and gas were converted to energy units (petajoules, PJ) based on: (oil) API (density) of each oil field and an average energy equivalent of $41.87 \text{ GJ}/1000 \text{ kg}$; (gas) gross heating value (GHV) of each particular gas field. (b) Based on the same principles an analogous creaming curve was generated for the oil and gas resources discovered in the onshore and offshore areas of the SNSB area of the UK. Some oil and gas discoveries were made in the UK prior to 1965, mostly in Carboniferous formations, yet owing to their small contribution they cannot be appreciated in this figure. This also applies to small discoveries made in Jurassic formations onshore. The data from the Netherlands and UK were delivered by TNO-Geological Survey of the Netherlands, and by the UK's Oil and Gas Authority respectively. The names of the fields shown in the figure derive from publicly available data (see Doornenbal & Stevenson 2010, appendix 3).

Table 1. Energy content (in PJ and bcm Groningen equivalent gas volumes) of hydrocarbon resources discovered in the SNSB area before and after 2007 for the UK and the Netherlands (small fields and Groningen Field)

	UK SNSB area fields $\times 10^3$ PJ (bcm Geq.)	Netherlands small fields $\times 10^3$ PJ (bcm Geq.)	Groningen Field $\times 10^3$ PJ (bcm Geq.)	Netherlands geothermal produced heat $\times 10^3$ PJ (bcm Geq.)
1940–2006	78.2 (2223)	110.8 (3149)	102.0 (2900)	n.a.
2007–17	1.4 (40)	4.1 (115)	n.a.	0.012 (0.345)
Total	79.6 (2263)	114.8 (3264)	102.0 (2900)	0.012 (0.345)

For comparison the Netherlands geothermal produced heat (in PJ and bcm Geq) in the period 2007–17 is given.

Although the majority of discoveries made in the period 2007–17 belong to the classic Rotliegend play, new plays were also successfully tested. For example, the F17-NE Rembrandt offshore oil field (2012) was found at a time when some argued that most, if not all, Chalk prospects related to salt domes had already been drilled. Another significant Rotliegend discovery was announced in September 2017 with the find of the Ruby gas field. The reservoir of the Ruby Field consists of basal Slochteren clastics (Upper Rotliegend Group) deposited in a north–south-trending syn-depositional graben, extending in an area north of the classic fairway where many did not anticipate petroleum potential. This new basal Upper Rotliegend play straddles the German–Dutch offshore border and may lead to new exploration activity in German waters unseen for a long time. In the UK, full appreciation of the hydrocarbon potential along the northern margin of the SPB in the Rotliegend only took place in recent years through the appraisal of the Cygnus Field. The most recent development in the UK was the attempt to extend the limits of the Carboniferous play, which led to important discoveries such as the Pegasus gas fields. A well drilled to test the Carboniferous beneath the Rotliegend in Ravenspurn proved to be unsuccessful, however. In the UK onshore, the Weald Basin made it to the news headlines in 2014 when the Horse-Hill discovery was announced. This is another example of how mature basins continue to deliver success.

In general the SNSB area has been quite successful in the timeframe with a success rate in exploration exceeding 60% in the Netherlands and slightly lower in the UK (EBN 2015). Although disappointments are relatively uncommon in the mature basin, estimation of actual volumes remains an issue.

Another interesting development in recent years is the emerging geothermal exploration and production activity. So far, this has taken place mainly in the onshore Netherlands, where aquifers in the Upper Jurassic/Lower Cretaceous formations have been targeted in the SW of the country. In this area there is a high local demand for heat from commercial greenhouse owners. Today, there are 14 operational geothermal installations in the Netherlands (Figs 2 &

3; Appendix B). They are mostly concentrated to the SW of the Netherlands, but applications for new geothermal exploration licences foresee the proliferation of geothermal to other parts of the country. Geothermal heat is a significant part of the future energy mix both for direct use for heating greenhouses and buildings but also for industrial processes which need temperatures above 120°C (Anonymous 2018a). Therefore, the interest in ‘Ultra Deep’ (>4 km) aquifers such as the Lower Carboniferous is evaluated in detail (Fig. 13), besides continued exploration efforts, including seismic acquisition (Anonymous 2019) to unlock as much geothermal potential as possible.

In terms of energy content, the contribution of the different discoveries becomes clear when the UK fields, the Groningen Field, the Dutch small fields and the current geothermal developments are compared (Table 1). The amount of thermal energy (initially natural gas) found in the Groningen Field (of c. 102×10^3 PJ, is roughly equivalent to the cumulative energy content found in all of the small fields discovered in the Netherlands, which is 115×10^3 PJ (initially natural gas and oil) (Fig. 12 and Table 1). It is important to mention that the recovery factor of the GIIP can vary between 70 and 90% while the STOIIP can vary between 10 and 40%. Nevertheless, the total amount of energy from hydrocarbon resources in the Netherlands is still enormous compared with the current potential of geothermal energy (Fig. 13). In 2017, an annual heat of 3 PJ was produced from the 14 operational geothermal installations (Fig. 13). Assuming a life expectancy for a geothermal field of up to 30 years, this means that the thermal energy potential of these current 14 operational geothermal systems is about 90 PJ. Annual production of geothermal energy is expected to grow to 50 and 200 PJ by 2030 and 2050, respectively (Anonymous 2018a). This means a total energy content of up to a few thousand PJ.

Future developments

Although the SNSB area is undoubtedly regarded as a mature oil and gas province, with annual

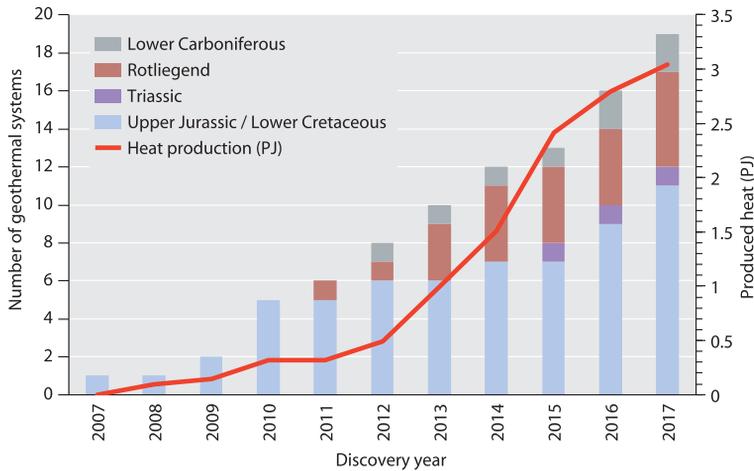


Fig. 13. Cumulative number of geothermal systems per lithostratigraphic unit in the period 2007–17 in the Netherlands (stacked bars). Annual geothermal heat produced from all operating geothermal systems (red line).

production continuously decreasing, the developments seen in the years between 2007 and 2017 show that the basin continues to surprise at times. This is further illustrated in Figure 12, where it can be seen that, despite a slowing down of the volumes discovered per year, new discoveries continue to be made every year. In general, we expect hydrocarbon potential to be found in each stratigraphic level in relative proportion to shown resources (Fig. 12). The mainstay Rotliegend remains the highest potential, although the relatively unknown Carboniferous play (both Upper and Lower) may conceal significant resources. Most other plays will only have a minor role in future exploration. Total developed resources found in the mature SNSB area comprise roughly 90% of its potential (MEA 2018), with a further 10% still to be developed under current conditions.

Future developments in the area will depend on how new plays such as the Chalk play in the Dutch Central Graben and the basal Upper Rotliegend play in the German–Dutch offshore area will perform. In addition, there may be further exploration along the southern margin of the Mid North Sea High in both the UK and Dutch sectors where the Lower Carboniferous is still relatively underexplored. The same area may also hold potential in the Zechstein, as shown by Patruno *et al.* (2018). There will almost certainly also be some remaining potential in the traditional Triassic (Kortekaas *et al.* 2018) and the Rotliegend plays (Catto *et al.* 2018).

With a strong public and political backing of a shift from fossil fuels to renewable energy, it is expected that the years to come will see an increased activity and diversification of plays pursued for geothermal exploration. As an example, in the

Netherlands an extensive study has been launched into the feasibility of geothermal energy production from deep Lower Carboniferous limestones. Similar research has been carried out in the UK where Lower Carboniferous limestones also form a potential target (Narayan *et al.* 2018). This is not only an interesting development from a geological perspective, it also brings a shift in exploration from offshore back to onshore, as geothermal energy production still relies on a market close to the site of production.

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HFM: Writing – Original Draft (Equal); **SN**: Writing – Original Draft (Supporting); **TCP**: Writing – Original Draft (Equal); **JHTV**: Writing – Original Draft (Equal); **MTB**: Writing – Original Draft (Supporting); **KVO**: Writing – Original Draft (Supporting); **RMCHV**: Writing – Original Draft (Supporting); **JMV**: Writing – Original Draft (Supporting); **G-JV**: Writing – Original Draft (Equal)

Appendix A

Dataset of hydrocarbon fields discovered in the period 2007–17, ordered by stratigraphical interval, discovery year and field name.

No	Hydrocarbon field name	Discovery year	Discovery well	Fluid type	Status 31-12-2017	NL/UK
<i>Upper Carboniferous</i>						
1	D15 Tourmaline	2007	D15-05-S1	gas	undeveloped, production start expected within 5 years	NL
2	Katy	2007	44/19b-6	gas	producing	UK
3	Wingate	2008	44/24b-7	gas	producing	UK
4	Fulham	2010	44/28a-6	gas	undeveloped	UK
5	Cameron	2011	44/19b-7A	gas	undeveloped	UK
6	Carna	2011	43/21b-5Z	gas	undeveloped	UK
7	Pegasus North	2011	43/13b-6Z	gas	undeveloped	UK
8	Severn	2013	43/18a-2Y	gas	untested hydrocarbons	UK
9	E11-Vincent	2014	E11-01	gas	undeveloped, production start unknown	NL
10	Pegasus West	2014	43/13b-7	gas	undeveloped	UK
11	Sillimanite	2015	44/19a-8	gas	undeveloped	UK/NL
12	Winchelsea	2016	44/23g-14	gas	undeveloped	UK
<i>Rotliegend</i>						
13	48/06-42	2007	48/06-42	gas	untested hydrocarbons	UK
14	Amanda	2007	49/11a-9	gas	undeveloped	UK
15	Cronx	2007	48/22b-6	gas	undeveloped	UK
16	Eos	2007	48/11c-13	gas	undeveloped	UK
17	Epona	2007	53/05a-8Z	gas	undeveloped	UK
18	Eris	2007	47/08c-4	gas	producing	UK
19	Faan	2007	FAN-01	gas	producing	NL
20	Victoria	2007	49/17-14	gas	producing	UK
21	Witterdiep	2007	WIT-02-S1	gas	suspended	NL
22	Doris	2008	48/30a-19	gas	untested hydrocarbons	UK
23	Fizzy	2008	50/26b-6	gas	undeveloped	UK
24	L05b-A	2008	L05-11	gas	undeveloped, production start unknown	NL
25	L09-FK	2008	L09-FA-103	gas	producing	NL
26	Vantage	2008	49/17-15	gas	untested hydrocarbons	UK
27	Andrea	2009	48/15b-10	gas	undeveloped	UK
28	Glein	2009	48/11a-12	gas	undeveloped	UK
29	Juliet	2009	47/14b-10	gas	producing	UK
30	K09c-B	2009	K09-12	gas	undeveloped, production start expected within 5 years	NL
31	K15-FP	2009	K15-FB-108	gas	producing	NL
32	L06-B	2009	L06-07	gas	producing	NL
33	K09ab-C	2010	K09AB-B-05	gas	suspended	NL
34	K09ab-D	2010	K09AB-B-06	gas	producing	NL
35	K15-FQ	2010	K15-FK-106	gas	suspended	NL
36	L05a-D	2010	L05-12-S1	gas	producing	NL
37	Olympus	2010	48/12e-11	gas	undeveloped	UK
38	Platypus	2010	48/01a-5	gas	undeveloped	UK
39	47/15b-5	2011	47/15b-5	gas	undeveloped	UK
40	Blija-Zuid	2011	BLF-108	gas	producing	NL
41	K12-L	2011	K12-18-S4	gas	producing	NL
42	Metslawier-Zuid	2011	TBN-01	gas	producing	NL
43	Monkwell	2011	42/29-6	gas and condensate	undeveloped	UK
44	Tolmount	2011	42/28d-12	gas and condensate	undeveloped	UK
45	Donkerbroek-West	2012	DKK-04	gas	producing	NL
46	K12-M	2012	K12-19-S1	gas	producing	NL
47	L10-N	2012	L10-36-S1	gas	producing	NL
48	Wieringa	2012	KBB-04	gas	producing	NL
49	Burum-Oost	2013	WFM-02	gas	production ceased	NL
50	Pharos	2013	47/05d-6	gas	undeveloped	UK

(Continued)

No	Hydrocarbon field name	Discovery year	Discovery well	Fluid type	Status 31-12-2017	NL/UK
51	Assen-Zuid	2014	WIT-04	gas	undeveloped, production start expected within 5 years	NL
52	Cepheus	2014	44/12a-6	gas	undeveloped	UK
53	Diever	2014	DIV-02	gas	producing	NL
54	L10-O	2014	L10-37-S1	gas	producing	NL
55	Romeo	2014	47/14b-11	gas	undeveloped	UK
56	L09-FM	2015	L09-FA-105	gas	producing	NL
57	L10-P	2015	L10-38-S2	gas	producing	NL
58	L11-Gillian	2015	L11-14	gas	producing	NL
59	Pieterzijl Oost	2015	WFM-03	gas	suspended	NL
60	J09 Alpha North	2016	K07-13	gas	undeveloped, production start unknown	NL
61	K09c-C	2017	K09-13	gas	undeveloped, production start expected within 5 years	NL
62	Ruby	2017	N05-01-S1	gas	undeveloped, production start expected within 5 years	NL
<i>Zechstein</i>						
63	P11b-Van Nes	2007	P11-05	gas	production ceased	NL
64	De Hoeve	2010	DHV-01	gas	producing	NL
65	Langezwaag	2011	LZG-01	gas	producing	NL
66	Nieuwehorne	2011	NWH-01	gas	undeveloped, production start unknown	NL
67	Zuidwijk	2012	ZWK-01	gas	undeveloped, production start unknown	NL
<i>Triassic</i>						
68	P10b-Van Brakel	2007	P10-05	gas	undeveloped, production start unknown	NL
69	G16a-B	2008	G16-A-03	gas	producing	NL
70	L09-FL	2008	L09-FB-102	gas	producing	NL
71	P11b-Van Ghent	2008	P11-06	oil+gas	producing	NL
72	Q01-D	2008	Q01-27	gas	producing	NL
73	Q14-A	2008	Q14-03	gas	undeveloped, production start unknown	NL
74	G16a-C	2009	G16-09	gas	producing	NL
75	Oudeland	2010	NMD-01	gas	producing	NL
76	Heinenoord	2011	BLK-01	gas	producing	NL
77	P11b-Van Ghent East	2011	P11-07	gas	undeveloped, production start expected within 5 years	NL
78	Q16-Maas	2011	MSG-03-S1	gas	producing	NL
79	G16a-D	2012	G16-B-04-S1	gas	producing	NL
80	De Klem	2013	NMD-02	gas	production ceased	NL
81	P10a-De Ruyter Western Extension	2013	P11-08-S1	gas	producing	NL
82	P11b-Witte de With	2013	P11-09	gas	undeveloped, production start expected within 5 years	NL
83	Oudendijk	2014	NMD-03	gas	producing	NL
84	P11a-E	2014	P11-11	gas	producing	NL
85	P15-19	2014	P15-RIJN-A-09-S2	gas	suspended	NL
86	L09-FM	2015	L09-FA-105	gas	producing	NL
87	P18-7	2015	P18-07	gas	undeveloped, production start expected within 5 years	NL
88	P11-12	2016	P11-12	gas	producing	NL
<i>Lower+Middle Jurassic</i>						
89	Markwells Wood	2010	Markwells Wood-1	oil	undeveloped	UK
<i>Upper Jurassic/Lower Cretaceous</i>						
90	Vinkega	2009	VKG-01	gas	producing	NL
91	Horse Hill	2014	Horse-Hill-1	oil	undeveloped	UK
<i>Upper Cretaceous</i>						
92	F17-NE (Rembrandt)	2012	F17-10	oil	undeveloped, production start expected within 5 years	NL
93	F06b-Snellius	2014	F06-06-S2	oil	undeveloped, production start expected within 5 years	NL
94	F06b-Zulu North	2014	F06-05	oil	undeveloped, production start unknown	NL
95	F17-SW Culmination	2014	F17-12	oil	undeveloped, production start expected within 5 years	NL

Appendix B

Dataset of geothermal systems discovered in the period 2007–17, ordered by stratigraphical interval, discovery year and geothermal system name.

No	Geothermal system	Discovery year	Discovery well	Fluid type	Status 31-12-2017	NL/UK
<i>Lower Carboniferous</i>						
101	Californie Geothermie (near Venlo)	2012	CAL-GT-01	geothermal	producing	NL
102	Californie Lipzig Gielen (near Venlo)	2016	CAL-GT-04	geothermal	producing	NL
<i>Rotliegend</i>						
103	Koekoekspolder Geothermie	2011	KKP-GT-01	geothermal	producing	NL
104	Heemskerk Geothermie	2013	HEK-GT-01-S2	geothermal	producing	NL
105	Middenmeer Geothermie I	2013	MDM-GT-01	geothermal	producing	NL
106	Middenmeer Geothermie II	2014	MDM-GT-03	geothermal	producing, from feb-18 as MDM-GT-02/MDMGT-05	NL
107	Middenmeer III	2017	MDM-GT-05	geothermal	startup phase	NL
<i>Triassic</i>						
108	Vierpolders Geothermie	2015	BRI-GT-01	geothermal	producing	NL
<i>Upper Jurassic/Lower Cretaceous</i>						
109	Installatie Bleiswijk	2007	VDB-GT-01	geothermal	producing	NL
110	Installatie Berkel en Rodenrijs	2009	VDB-GT-03	geothermal	producing	NL
111	Den Haag Geothermie	2010	HAG-GT-01	geothermal	undeveloped, production start expected within 5 years	NL
112	Pijnacker-Nootdorp Geothermie	2010	PNA-GT-01	geothermal	producing	NL
113	Pijnacker-Nootdorp Zuid Geothermie	2010	PNA-GT-03-S2	geothermal	producing	NL
114	Honselersdijk Geothermie	2012	HON-GT-01-S1	geothermal	producing	NL
115	De Lier Geothermie	2014	LIR-GT-01	geothermal	producing	NL
116	Kwintseul Geothermie	2016	KHL-GT-01	geothermal	startup phase	NL
117	Poeldijk	2016	PLD-GT-01	geothermal	producing	NL
118	Lansingerland	2017	LSL-GT-01	geothermal	startup phase	NL
119	Maasland	2017	MLD-GT-01	geothermal	startup phase	NL

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