DANMARKS OG GRØNLANDS GEOLOGISKE UNDERSØGELSE **RAPPORT 2020/49**

Hydrocarbon Play Maps in the Danish Central Graben

Niels H. Schovsbo, Finn Jakobsen & Peter Britze

GEOLOGICAL SURVEY OF DENMARK AND GREENLAND
DANISH MINISTRY OF CLIMATE, ENERGY AND UTILITIES

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Table of Content

Abstract

Between 1993 and 2017, Denmark was one of the largest oil exporting countries in Europe having gained this position from its share in the highly prolific Danish Central Graben whereas the area outside the Central Graben has a little and highly uncertain resource. Here, 12 play maps for the Danish Central Graben ranging from the well-established Upper Cretaceous chalk play to the unproved plays within the Farsund Formation and the newly established Heno and Neogene plays are presented as originally described by Andersen *et al.* (2015). For each play the resource is estimated based on an evaluation of 21 discoveries and 72 prospects and leads. Within the discovery portfolio it is estimate that an addition resource of 246 million m^3oe is present within the Danish Central Graben and an additional 190 million m^3oe (risked) resource is present within the yet-to-find category. For most plays the main petroleum source rocks is the Upper Jurassic – lowermost Cretaceous Farsund Formation. The Middle Jurassic coaly units of the Bryne and Lulu Formations constitute a secondary source, whereas unknown contribution may come from other source rocks including the Upper Jurassic Lola Formation, the Lower Jurassic Fjerritslev Formation, Permian shales and Carboniferous coals.

Introduction

Between 1993 and 2017, Denmark was one of the largest oil exporting countries in Europe having gained this position from its share in the highly prolific Danish Central Graben whereas the area outside the Central Graben has a little and highly uncertain resource (c.f. Schovsbo & Jakobsen, 2019). In this report we focus on the Danish Central Graben (DCG) that is part of the North Sea rift basin (Figure 1). The main petroleum source rocks of this mature petroleum province are the Upper Jurassic – lowermost Cretaceous marine shales, which are referred to as the Farsund Formation in the DCG, the Kimmeridge Clay Formation in the UK sector and the Mandal Formation in the Norwegian part of the Central Graben. The Middle Jurassic coaly units of the Bryne and Lulu Formations constitute a secondary source, whereas unknown contribution may come from other source rocks including the Upper Jurassic Lola Formation, the Lower Jurassic Fjerritslev Formation, Permian shales and Carboniferous coals (see Pedersen & Hertle, 2018 and Schovsbo *et al*., 2020 for recent reviews).

The Jurassic – lowermost Cretaceous source rocks mainly charged the Cretaceous – Palaeogene Chalk Group from where the main hydrocarbon production occurs in the DCG (Figure 2 and 3). Secondary production occurs from Middle Jurassic and Palaeogene sandstones and more recently also from Upper Jurassic and Miocene sandstones. Exploration of other Upper Jurassic plays has led to the Hejre-1, Amalie-1, Svane-1 and Xana-1X high-pressure and high-temperature (HPHT) discoveries (Figure 3). These discoveries were made in fan delta sandstones and offshore gravity flow deposits (Figure 3).

The first regional review of the quality and maturity of all Jurassic source rocks in the DCG was presented by Damtoft *et al.* (1987). Since then, the amount of source rock data and the regional stratigraphic knowledge has advanced considerably (Ineson & Surlyk, 2003). A second major advancement in our understanding was gained from the 'Jurassic Petroleum System Project' (PETSYS) completed in 2014. Important results from this project have been published by Johannessen *et al.* (2010) on sedimentology and by Petersen *et al.* (2010, 2011, 2012, 2013) and more recently Ponsaing *et al.* (2018, 2020a,b) and Schovsbo *et al.* (2020) on source rock quality and maturity.

The lithostratigraphy for the Jurassic to Neogene in the DCG is presented in Figure 3. In the Early Jurassic the DCG was characterized by a relatively slow sea level rise and deposition of the grey, shallow-marine shales of the Fjerritslev Formation. During the latest Early Jurassic – earliest Middle Jurassic the area was uplifted and the Triassic and most of the Lower Jurassic succession was removed by erosion. Due to this Toarcian erosion, parts of the Fjerritslev Formation are not present in the DCG. Mid-Jurassic rifting caused fault-controlled subsidence in the east, particularly along N–S trending segments of the Coffee Soil Fault. Because of the renewed subsidence and subsequent flooding of the DCG, the lower part of the Middle Jurassic is dominated by fluvial-channel sandstones assigned to the Bryne Formation. The upper part is characterized by paralic sandstones, shales and coal beds, which are overlain by shoreface and back-barrier deposits. During Oxfordian – Kimmeridgian, deep-water conditions were created in the DCG and the marine shales of the Lola Formation were deposited. The shallow-marine and back-barrier sandstones of the Heno Formation were deposited on the Heno and Gertrud plateaus during the late Kimmeridgian. The depositional area gradually extended westwards and the thick, shale-dominated marine succession of the Farsund Formation was deposited over larger areas. The subsidence rates were radically reduced in the latest Volgian, and the deposition of the organic-rich and highly radioactive 'hot shales' of the Bo Member (Volgian – Ryazanian) took place in most areas of the DCG. The transition from the Farsund Formation to the overlying Cromer Knoll Group (Valhall to Rødby Formation, Fig. 2) marks a basinwide facies change from organic-rich shales to carbonate-rich and organic-lean shales deposited in open-marine environments. This transition is generally termed the

Base Cretaceous Unconformity (BCU). The boundary marks the base of the deposits of the post-rift phase in the DCG, represented by the Cromer Knoll and Chalk Groups. In the Late Cretaceous to early Palaeogene, high sea level prevailed and the sedimentation shifted from siliciclastics to chalk composed of calcareous nanofossils and to a compressional tectonic regime.
The thickness of the Chalk Group (Hidra to Ekofisk Formations, Figure 3) varies from less than 200 m on inverted ridges to more than 1000 m in local depocentres in northern Tail End Graben, the Gertrud Graben and on the Heno Plateau. Deep burial of the Jurassic succession took place in the Paleocene to Neogene, and the depth to the top of the Chalk Group and top Jurassic ranges from 1600 to 3400 m and 2200 to 5000 m, respectively.

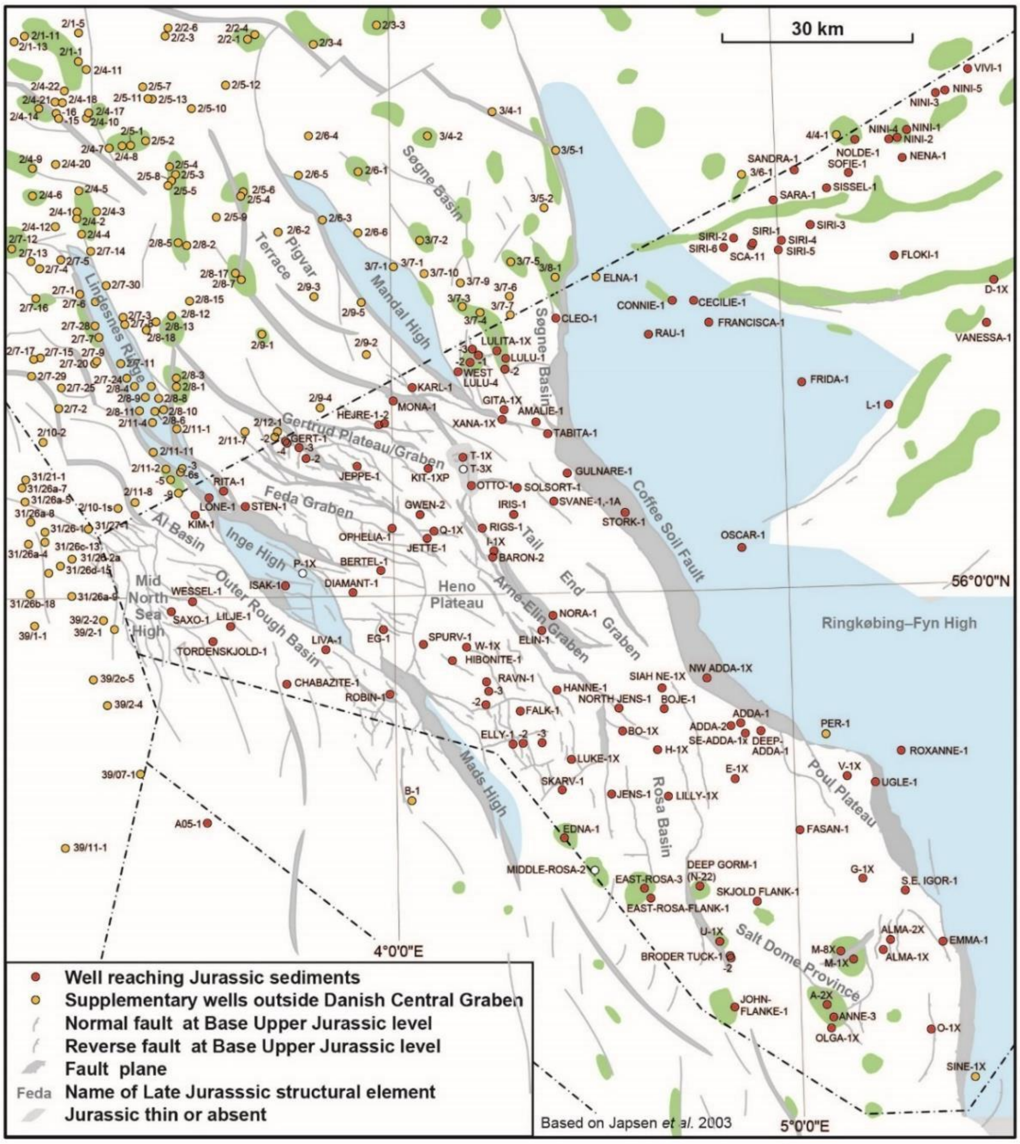

Figure 1: Well locations and structural outline. GIS map of structural elements in the Danish area is available as accompanying data (https://doi.org/10.22008/FK2/SFVSBM).

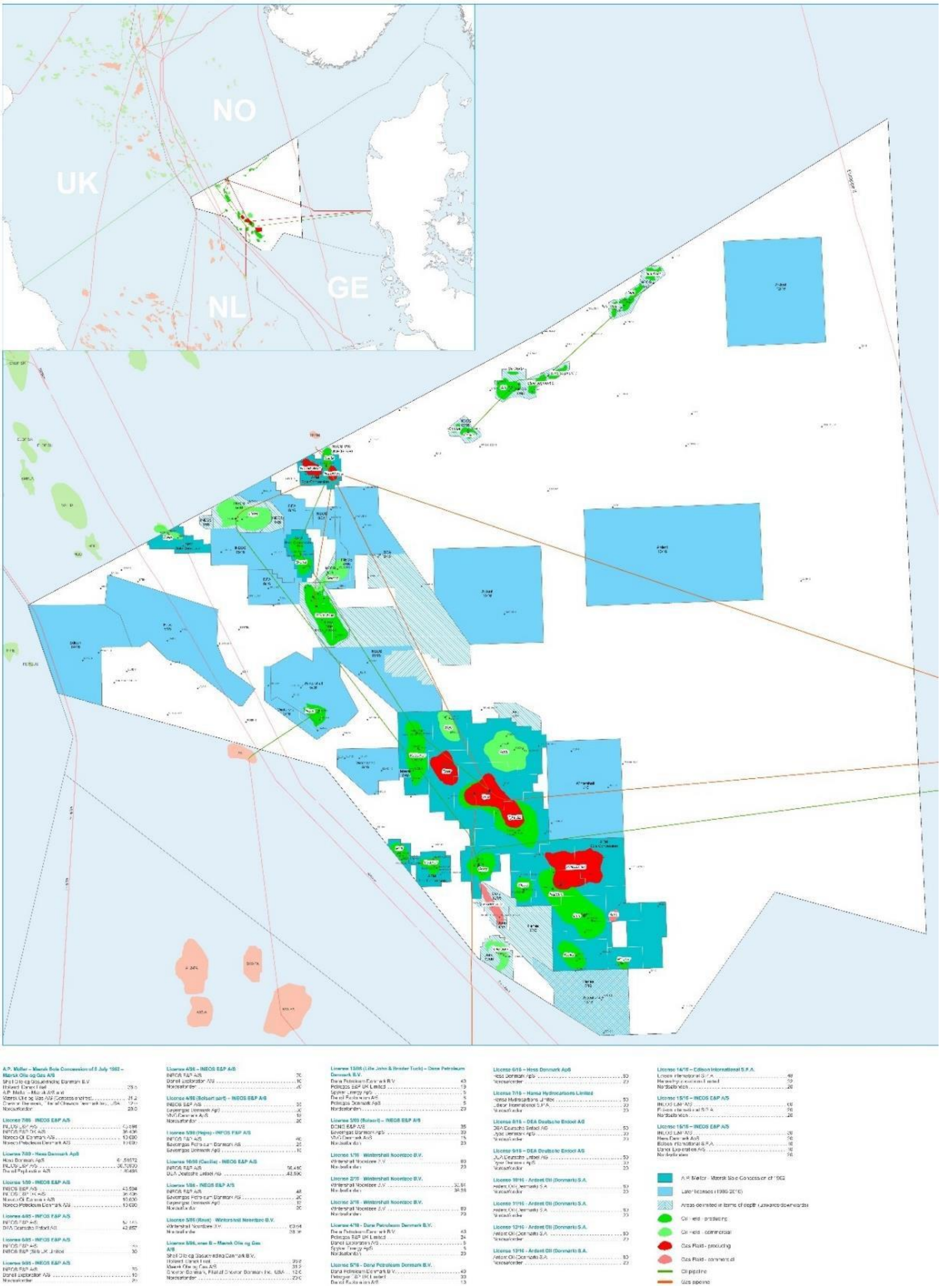

Figure 2: Danish oil and gas fields. From the Danish Energy Authorities (DEA). A GIS map of oil and gas fields in the Danish area is available as accompanying data (https://doi.org/10.22008/FK2/SFVSBM*).*

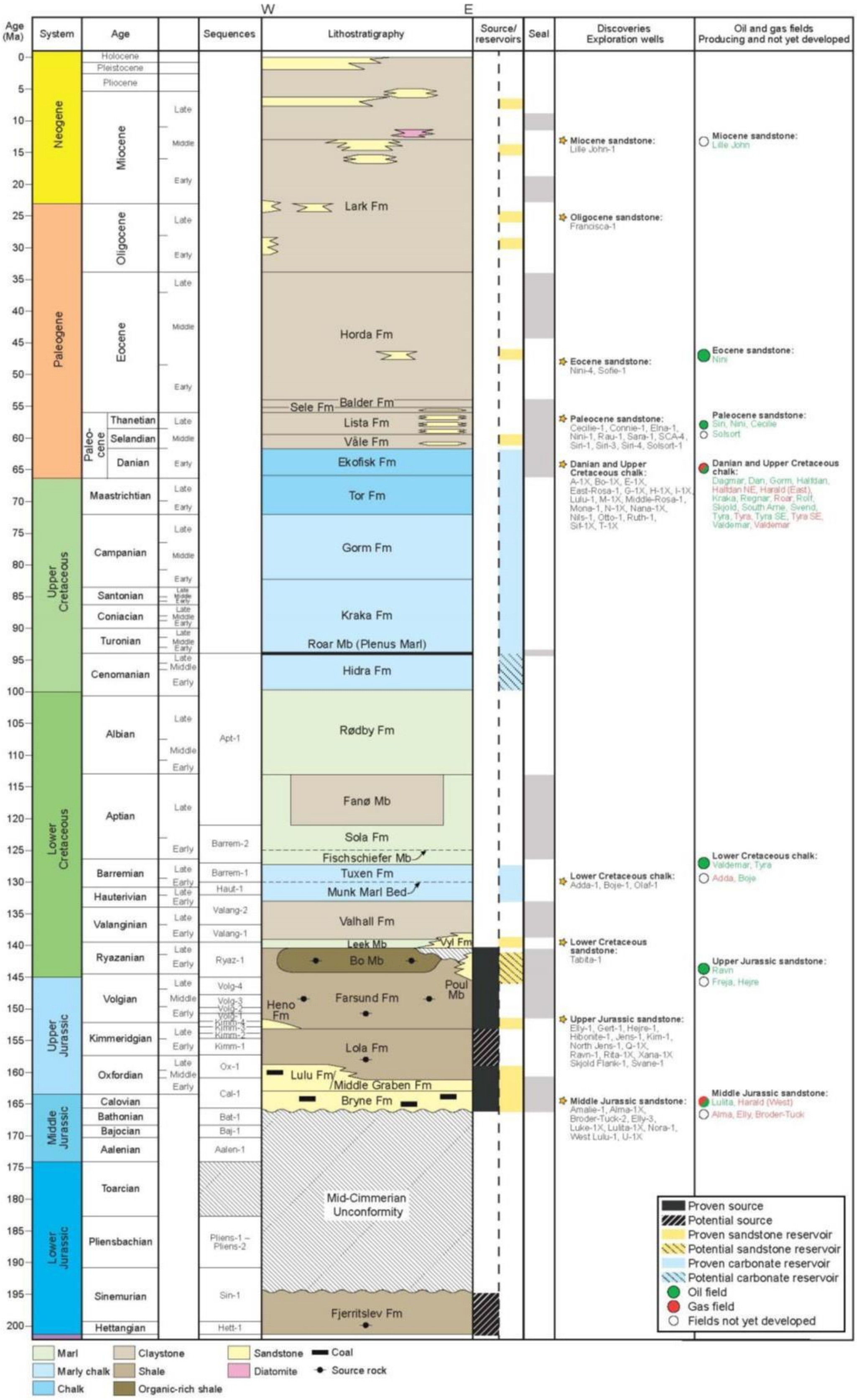

Figure 3: Lithostratigraphy with fields and discoveries in the Danish Central Graben. From Ponsaing et al. (2020a).

Play maps

The play maps and descriptions are based on the report “Vurdering af tilstedeværende olie/gas ressourcer i dansk Nordsø vest for 6°15´Ø” [Evaluation of the remaining oil/gas resource in the Danish North Sea West of 6°15´Ø”] prepared by Claus Andersen, Finn Jakobsen, Erik Thomsen and Nina Skaarup, all GEUS, in June 2015. In the context of the project “Geological Analysis and Resource Assessment of selected Hydrocarbon systems (GARAH)” the plays and descriptions have been further substantiated and all play outlies presented have been digitised. No new resource assessment is made here and the resources assessment present in the text and in Table 1 are all from Andersen *et al.* (2015). In the GARAH project evaluation of the unconventional plays and the risk evaluation of the conventional plays made by Andersen *et al*. (2015) will be addressed and therefore corrections of the resource assessment presented in Table 1 (on page 28) will occur.

By ‘play´ the geographical area is understood, where the geological factors that are a prerequisite for generation and trapping hydrocarbons can occur simultaneously. The following 12 play types are described and named after known productive reservoir intervals, but also more hypothetical intervals are described. For each play, experiences from exploration will be briefly mentioned, including fields and discoveries, as well as a summary description of the individual play elements with emphasis on reservoir properties and trap type.

Plays (see Figure 3 for stratigraphy):
1. Mid Jurassic sandstone gas / condensate play
2. Upper Jurassic Kimmeridgian shallow marine sandstone oil play (Heno Formation)
3. Upper Jurassic Volgian shallow water marine sandstone oil / gas play (Outer Rough sandstone)
4. Intra Farsund Formation sandstone oil / gas play (Kimmeridge - lower Volgian)
5. Upper Farsund Formation sandstone oil play (between Volgian - Ryazanian)
6. Lower Cretaceous Chalk oil / gas play (Tuxen and Sola Formations)
7. Upper Cretaceous Chalk oil / gas play (Hidra and Kraka Formations)
8. Upper Cretaceous Chalk oil / gas play (Tor and Ekofisk Formations)
9. Palaeogene sandstone oil / gas play
10. Neogene sandstone oil / gas play
11. Pre-Jurassic plays
12. Unconventional plays.

Play no. 2 - 10 dependent on the same well-established Upper Jurassic – lowermost Cretaceous Farsund Formation, while play no. 11 dependent on deep-lying source rocks of carbon age, which quality and distribution are very uncertain in the Danish Central Graben.

A GIS map version of the oil and gas plays are available as accompanying data from https://doi.org/10.22008/FK2/SFVSBM together with structural maps representing the Upper Ju- rassic configuration (c.f. Schovsbo *et al.*. 2020). The Danish structural map elements have been merged with a similar Jurassic structural elements maps covering the Norwegian part of the Central graben (https://www.npd.no/en/facts/geology/structure-elements/). The termination of the Danish structural map in the German part of the Central Graben are made here from a technical point of view only in order to close the polygons.

1. Mid Jurassic sandstone gas / condensate play

Production from the Jurassic interval was first established from the Mid Jurassic sandstones of the Bryne and Lulu formations within the Harald West and Lulita fields, both located in the north-eastern part of the Danish Central Graben near the Norwegian shelf border (Figure 2). Several minor discoveries have been made in Mid Jurassic sandstones (Alma, Amalie, and Elly, Figure 3), which at first were declared commercial, but have not yet been put into production. In recent years, the play has undergone a revival, as gas has been detected in 3 exploration wells, Gita-1, Luke-1, and Broder Tuck-2 / 2A, where the latter discoveries are being evaluated.

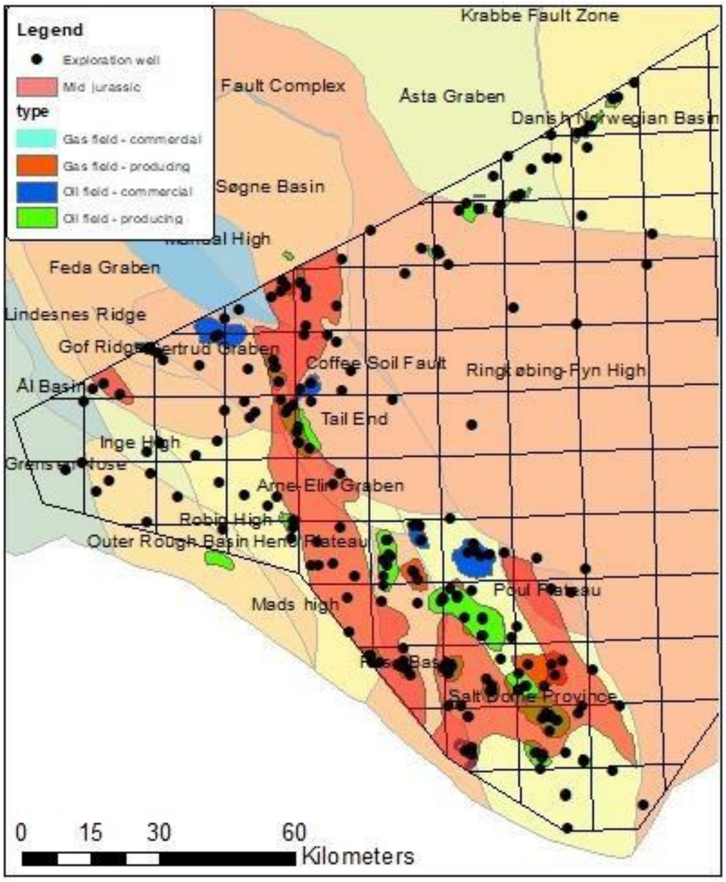

*Figure 4: Mid Jurassic sandstone gas / condensate play. GIS map of all play maps in the Danish area is available as accompanying data (*https://doi.org/10.22008/FK2/SFVSBM).

The Mid Jurassic sandstones are deposited in an overall fluvial-deltaic environment and are found throughout the eastern part of the Danish Central Graben. The sandstones have varying thickness and net / gross ratios and are buried at depths from 3000-4000 m to the south and to the north and to more than 7000 m in the eastern and central part of the Tail End Graben. The sands have a medium grainsize and include interbeds of coaly and carbonaceous shales, the latter acting as an efficient gas and local oil source (Pedersen & Hjertle, 2018). Due to differences in burial depths, there are marked variations in maturity (from early oil maturity to clearly overmature for dry gas) throughout the Danish Central Graben (Pedersen & Hjertle, 2018; Schovsbo *et al.*, 2020). The hydrocarbon phase in the Lulita field is oil.

The Mid Jurassic play is, however, generally considered a gas/condensate play and the oil producing Lulita field may represents an anomaly, possibly due to local oil-forming lacustrine deposits.

The trap type in the south and north of the play area is structural and associated with 4-way closures over deeper salt structures or along the flanks of salt pillows. In the central parts of the play area, traps linked to rotated fault blocks dominates. The expected play area is a 10-20 km wide elongated area bounded by the wedge of the Jurassic sequence to the west and the deeper parts of the Tail End Graben to the east, as shown on Figure 4. In defining the play, a depth delimitation of 5400 m has been used, as the reservoir quality below this level must be expected to be poor, just as HPHT conditions will complicate any drilling activities. Thus, the formation pressure is close to 100 MPa at approximal 5000 m depth in the Amalie-1 well, while in the Luke-1 well it is about 80 MPa at 4000 m. Farthest to the south the overpressure decreases.

Within the play area, relatively small prospects and structural leads have been mapped and only limited gas and/or condensate, typically less than 5 million m^3oe, are expected to occur. Andersen *et al.* (2015) estimated the total non-risk weighted P50 volume to be 38 million m^3oe (9 million m^3oe, risk weighted) within 11 structures. The area north of Elly, in the central part of the play area, is structurally very complex and covered by low quality seismic data. Here additional three unidentified leads related to rotated fault blocks or stratigraphic wedges may be present. Confirmation of this requires, however, access to improved seismic data. The size of these accumulation is estimated to be around 5 million m^3oe i.e. like the size of the discoveries in the Elly-Luke area.

2. Upper Jurassic Kimmeridgian shallow marine sandstone oil play (Heno Formation)

Upper Jurassic (Kimmeridgian) shallow marine to coastal sandstone deposited is present in the western part of the Central Graben on the so-called Heno Plateau. These deposits are assigned to the Heno Formation. Production from the Heno Formation has recently begun in the Ravn field situated on the shallower southern part of the Heno Plateau, where oil was also detected with a lower GOR (95 Sm^3 / Sm^3) (Pedersen *et al.*, 2018). Also, Heno Formation sandstones buried to more than 5000 m is an oil reservoir (44° API, GOR 550 Sm^3 / Sm^3) within the Hejre field, which is currently under development in the northern part of the play area. In addition, commercial quantities of oil have been found in the Freya / Mjølner field crossing the Danish-Norwegian border.

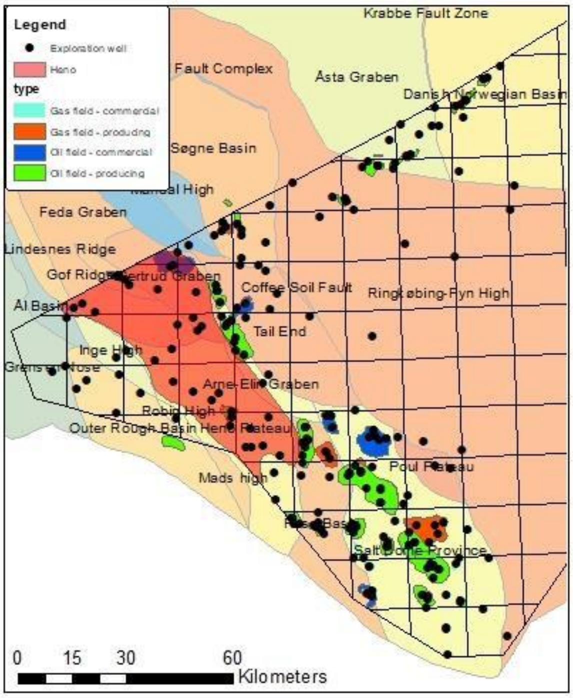

Figure 5: Upper Jurassic Kimmeridgian shallow marine sandstone oil play (Heno Formation).

The shallow marine sandstones belonging to the Heno Formation are in most of the distribution area at a burial depth of 4000 m to more than 5000 m, which is considered HPHT conditions (c.f. Schovsbo *et al.*, 2020). Within the area the thickness and reservoir quality vary considerably depending on the local depositional environments, location in the basin (accommodation space) and sediment supply. The lower part of the Farsund Formation is in several wells very rich in organic material and oil-mature and directly overlays the reservoir. The main trap type is associated with rotated fault blocks bounded by faults on one or more sides. Migration from source to reservoir can occur along contact surfaces in the fault zones. Several potential structural traps that have not yet been drilled have been identified and therefore, the Heno play likely hold an additional resource. Andersen *et al.* (2015) estimated the total non-risk weighted P50 volume in prospects and leads to be 102 million m^3oe (21 million m^3oe, risk weighted) divided into 15 structures. They found that the mapped structures were evenly distributed within the play area, and thus considered it unlikely that additional leads will be identified in the future.

3. Upper Jurassic Volgian shallow water marine sandstone oil / gas? play (Outer Rough sandstone)

The distribution of shallow water marine sandstone of Volgian age (Outer Rough sandstone) is limited to the westernmost part of the Central Graben on the flanks of the Mid North Sea High (Figures 1, 6). On the Danish side, this type of sandstone has only been drilled in two wells situated on rotated fault blocks. The poor data material indicates a very varying thickness and reservoir quality. The Saxo-1 well drilled more than 60 m of sand with high porosity and permeability suggesting that high quality reservoirs maybe present in the area. However, none of the wells detected hydrocarbons in commercial quantities. The dry wells were attributed to a combination of poor seal and difficult migration routes from the source rock(s). In this part of the Central Graben, the otherwise prolific organic-rich Farsund Formation is thin and only early mature for oil generation. An alternative source in the area may, however, be older Paleozoic rocks, e.g. gas-forming Carboniferous strata, which are the source of the nearby German A6-B4 field (Figure 2).

Several minor leads have been mapped in connection with previous licensing rounds. In the portfolio, however, only two possible prospects were selected by Andersen *et al.* (2015) with a total non-risk weighted P50 volume calculated to be 44 million m^{3}oe (7 million m^{3}oe, risk weighted). A low probability of discovery was estimated due to the above-mentioned factors combined with the fact that it is critical to have a resolution of the seismic data that can resolve these thin reservoirs. The two prospects and leads are considered to cover the potential of this non-proven play.

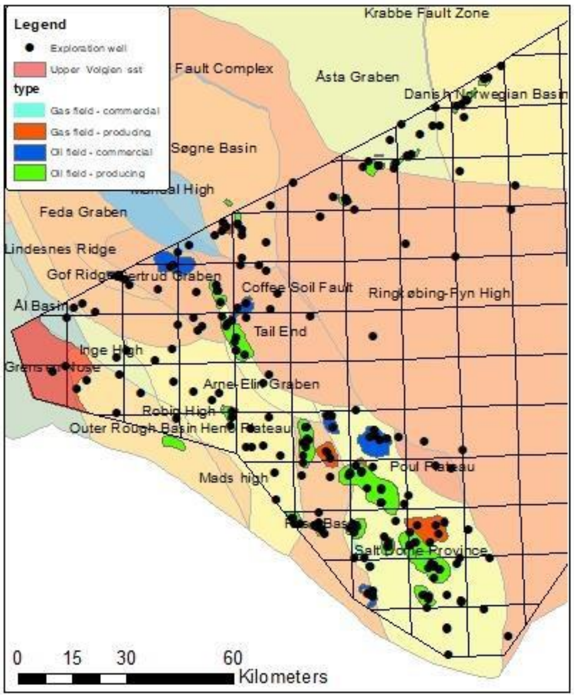

Figure 6: Upper Jurassic (Volgian) shallow marine sandstone oil / gas play (Outer Rough sandstone).

4. Intra-Farsund Formation sandstone oil / gas play (Kimmeridge - lower Volgian)

Basin floor fan deposited sandstones embedded in the Farsund Formation source rock has within the last decades attracted renewed exploratory interest. In 2002, the Svane-1 exploration well was completed to a depth of almost 6000 m in the northern part of the Tail End Graben. Here, gas-saturated sandstones of Kimmeridge age from a depth of approximately 5300 m under HPHT conditions on a 4-way closure was found. However, the Svane discovery was subsequently declared sub-commercial and technically difficult to assess, after which the license was relinquished.

Later, Gita-1 was drilled on a sloping fault block west of the Amalie-1 well with a 300 m interval of stacked sandstones with reservoir quality, but without hydrocarbons. South of Gita-1, the Xana-1 well encountered oil in the same sandstone interval. The sandstone interval in the two wells is presumably the same age as the sandstones in the Svane discovery. These results therefore suggest the presence of an attractive gas and oil play in the northernmost part of the Tail End Graben, where turbidite sandstone is deposited as basin floor fans embedded in the lower part of the several km thick organic-rich Farsund Formation (Figure 7). Here, two prospects are mapped both located on the hanging block of faults.

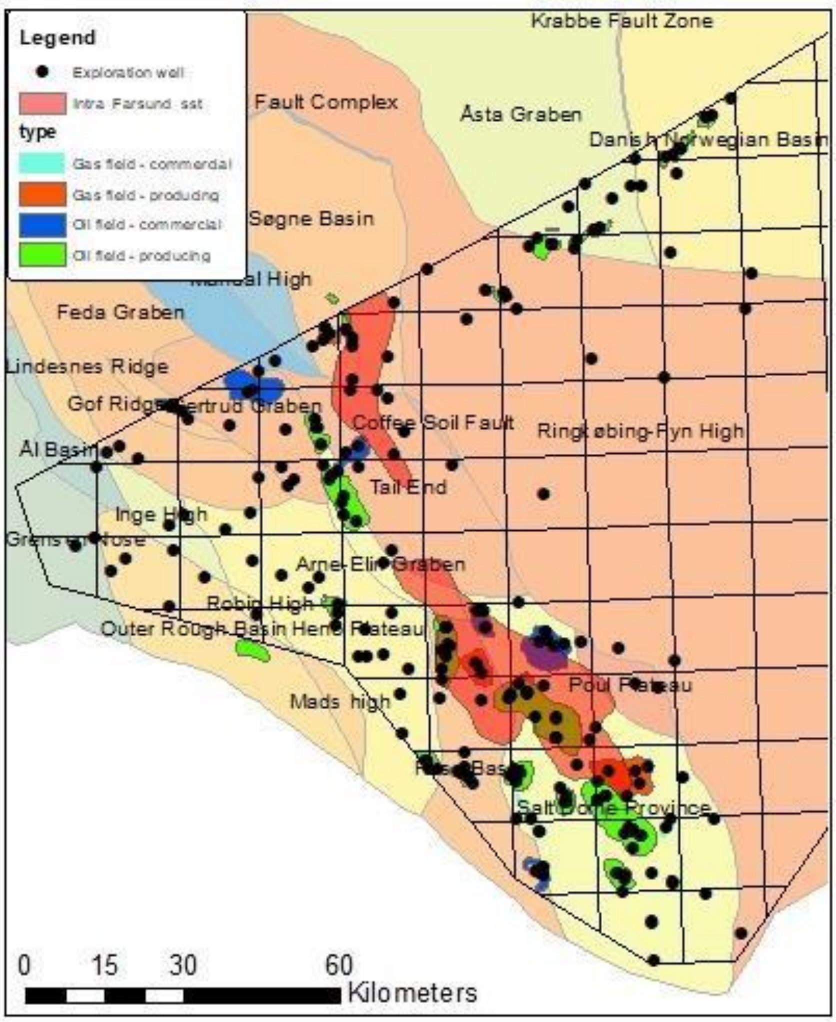

Figure 7: Intra-Farsund Formation sandstone oil / gas play (Kimmeridge - lower Volgian).

Seismic data have in several places in the Tyra area identified lobe systems of Kimmeridge age at about 4000 m depth suggesting that this play also extends to the south as shown in Figure 7. Results obtained by seismic elastic inversion are here compatible with the presence of hydrocarbon-bearing sandstone.

Andersen *et al.* (2015) estimate the total non-risk weighted P50 volume for known prospects to be 81 million m^3oe (27 million m^3oe, risk weighted). It is noted that there is a very large spread in the size distribution of the identified prospects. If future drilling activities can demonstrate the presence of a reservoir in this part of the Farsund formation south of the Svane discovery, it is conceivable that the play area can be expanded to the south and the portfolio expanded with a mapping of an additional prospects in the 20 million Sm^3 oil range in the Tail End Graben and in the Salt Dome Province (Tyra area) as shown on Figure 7.

5. Upper Farsund Formation sandstone oil play (Volgian - Ryazanian)

Sandstone deposited as basin floor fans embedded in the upper part of the Farsund Formation source rocks or as ‘gravity flows’ associated to the main fault zone of the Ringkøbing-Fyn High has been an exploration target in several wells. The play has also gained renewed interest and several prospects and leads have been identified.

The exploration results from a number of wells have shown that the Volgian – Ryazanian part of the Farsund Formation is clay-dominated without reservoir intervals with the exception of sandy beds of varying reservoir quality deposited as ‘gravity flows' along the main fault to Ringkøbing-Fyn High (i.e. Poul Sand) and thin turbidite intervals in the basin areas (cf. Figure 3). The only exception to this was the results from the Amalie-1 well in the northern part of the Central Graben, where a thin sand layer at 4300 m depth with high formation pressure and porosity between the Farsund shale and the overlying Lower Cretaceous Valhall Formation was drilled. However, a subsequent appraisal well found only traces of sand with minor shows and the interval has not been a target for further drilling.

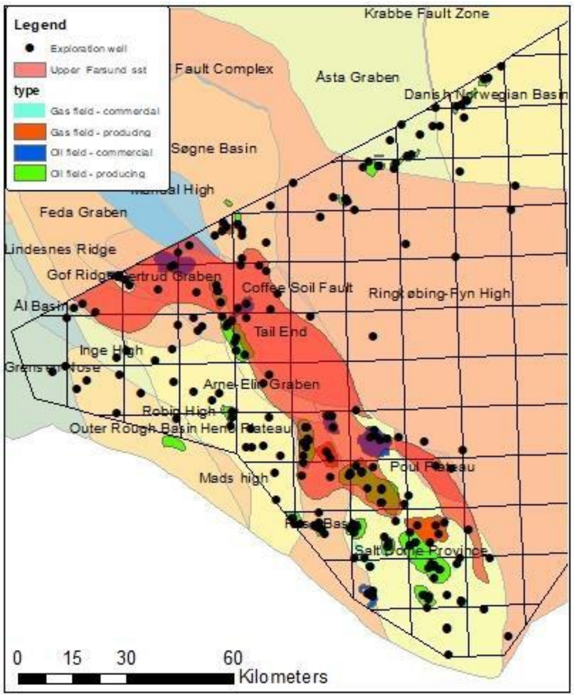

Figure 8: Upper Farsund Formation sandstone oil play (Volgian – Ryazanian).

The outlined play area in Figure 8 includes the northern and eastern parts of the Central Graben and is delineated by the limit of the thick upper Farsund Formation. The play is to be regarded as unconfirmed, disregarding the hydrocarbons detected in the Amalie-1 well. Traces of thin turbidite sandstone is documented from wells in the northern play area, but the distribution of the sandstone in the southern part of the play area is highly uncertain.

Nine prospects and leads with a generally low probability have been included in the portfolio. The depth ranges from about 3300 m to the south and to more than 4600 m to the north in the Hejre area where also a considerable overpressure can be expected for the formation here (c.f. Schovsbo *et al.*, 2020). Andersen *et al.* (2015) calculated the total non-risk weighted P50 volume to be 189 million m^3oe (30 million m^3oe, risk weighted).

6. Lower Cretaceous chalk oil / gas play (Tuxen and Sola Formations)

Lower Cretaceous chalk and marl are the main reservoir in the Valdemar / Bo field (Figures 2, 3). In addition, the same stratigraphic interval is also a reservoir in the Adda discovery (Figure 3), which is expected to be put into production within a few years. Finally, the potential for production below the Upper Cretaceous accumulations in the Syd Arne and Tyra fields are under assessment.
Traditionally, the Lower Cretaceous has been considered a secondary, deeper exploration target on structural traps identified at the Upper Cretaceous chalk level. The reservoir consists of hemi-pelagic chalk and marl belonging to the Tuxen Formation and to a lesser extent also the overlying Sola Formation (Figure 3). The interval lies between the Upper Jurassic to lowermost Cretaceous source rocks and the overlying hydrocarbon-saturated Upper Cretaceous chalk reservoirs and are thus advantageously on the migration route e.g. via crack and fault zones.
The reservoir quality in the Lower Cretaceous is controlled by the clay content. Porosities up to 35–40% have been observed in the Tuxen Formation on the Valdemar field at a depth of about 2500 m. The porosity decreases with increasing clay content and burial depth. The permeability is generally very low, which reduces productivity.

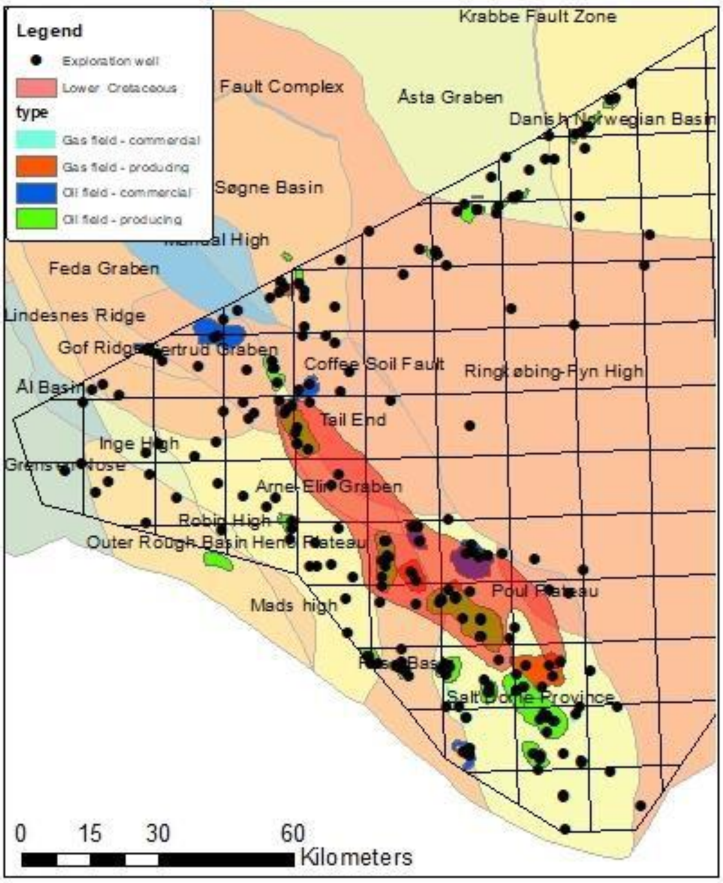

Figure 9: Lower Cretaceous chalk oil / gas play (Tuxen and Sola Formations)

The Tuxen Formation occurs over most of the Central Graben with varying thicknesses of more than 50 m. However, areas with average porosities above 25% seem to be limited to an area around the Valdemar-Tyra-Adda with an extension north towards the Syd Arne field (Figure 9). As the presence of hydrocarbons in the Tuxen Formation is often linked to the presence of hydrocarbons in the Upper

Cretaceous chalk, the development of chalk within the Lower Cretaceous play area could include both levels. Potential independent Lower Cretaceous stratigraphic traps in connection with wedge of reservoir have been identified seismically. However, this play has not yet been verified.

The inventory includes prospects in the Boje and Tyra area as well as a single lead north of the Valdemar field in the depth range from around 2600–2800 m. Andersen *et al.* (2015) estimated that the total non-risk weighted P50 volume is 41 million m^3oe (19 million m^3oe, risk weighted).

7. Upper Cretaceous Chalk oil / gas play (Hidra, Kraka Formations)

Structurally positioned oil has been found in the lower part of the Chalk Group i.e. the Hidra and Kraka formations (Figure 3) in the Adda and Bo / Valdemar areas above accumulations in the Lower Cretaceous Tuxen chalk, where the top seal is leaking. From here, however, production has not yet been established.

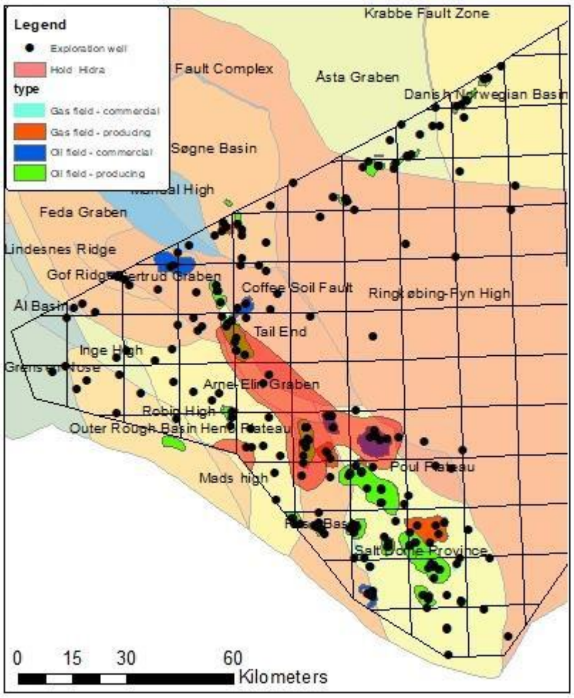

Figure 10: Upper Cretaceous chalk oil / gas play (Hidra and Kraka Formations).

The above-mentioned discoveries show that the chalk can act as both a reservoir and as a top seal. High porosities in the lower part of the Chalk Group appear to occur primarily, where the chalk contains zones with redeposited chalk at a moderate burial depth and with overpressure, which reduces the effective stress and thus mechanical and/or chemical compaction of the chalk. The play area (Figure 10) is comparable to the play area of the underlying Tuxen Formation (Figure 9) and is limited to the inversion anticline area in the central part of the Central Graben. It should be noted, however, that gas has been encountered in the lower part of the Chalk Group directly over the gas-bearing Heno Formation sandstone in the Elly-1 well to the west. Furthermore, a lead located east of the Adda discovery on the adjacent part of Ringkøbing Fyn High is included in the inventory. This is a seismic amplitude anomaly in the basal part of the Chalk Group, which may represent redeposited chalk from the nearby inversion ridge.

Three high-risk prospects and leads located in the Valdemar area within the depth range from around 2200–2500 m have been included in the inventory. Andersen *et al.* (2015) estimated that the total non-risk weighted P50 volume is 41 million m^3oe (4 million m^3oe, risk weighted).

8. Upper Cretaceous chalk oil / gas play (Tor and Ekofisk Formations)

Most Danish oil and gas production are from porous chalk reservoirs in the Ekofisk and Tor formations i.e. from the upper part of the Chalk Group (Figure 3). The dominant trap type is a 4-way structural closure over salt structures or on inversion anticlines. Despite a very mature exploration stage where all known structural traps at the chalk level have been drilled, the play was revived after the turn of the millennium due to the discovery of the Halfdan field northwest of the Dan field (Figure 2). The Halfdan field has reserves of 100 million m^3 and is linked to a possibly unique non-structural trap with a sloping oil-water contact in the Tor Formation as well as a pressure variations within the oil zone, which shows that the oil is not in equilibrium but is moving slowly. Subsequently, exploration activities in the chalk have been focused on locating Halfdan type accumulations with such dynamic traps or in purely stratigraphic traps without structural closure. The results have not been promising until now. Seismic inversion has shown to be an effective tool for predicting the presence of porous reservoir intervals in the chalk. The main challenge has been to predict the presence of hydrocarbons, which include likely migration routes from the Upper Jurassic to lowermost Cretaceous source rock and into the trap.

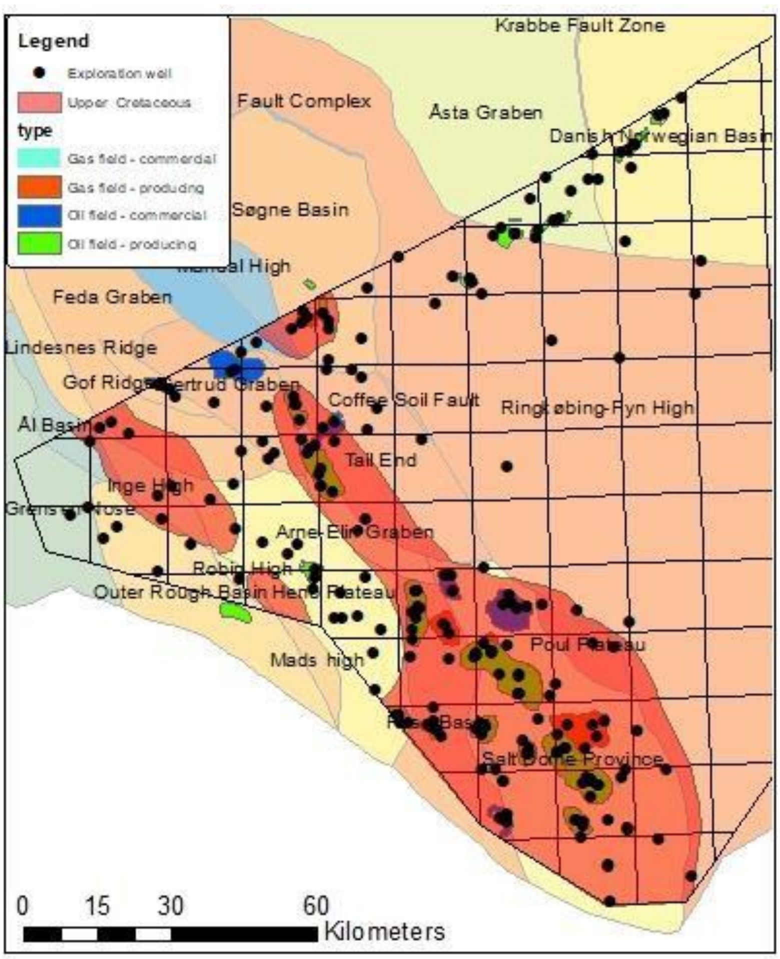

Figure 11: Upper Cretaceous chalk oil / gas play (Tor and Ekofisk Formations).

An estimate of the residual potential of the chalk is further complicated by the nature of the chalk itself with its low matrix permeability and strong capillary forces, as it is not possible to calculate the distribution of mobile and non-mobile oil in advance. At the same time, experience has shown that sloping free water level is more the rule than the exception, which makes predictions about its placement in any prospects very uncertain.

The estimate on the residual potential within the play includes 12 predominantly stratigraphic leads and prospects in the primary play area as shown in Figure 11. The depth of the play is in the order of 2000 m to the south increasing to about 3000 m to the north and west. Possible unrecognized resources have been included from fractured chalk over salt structures in the southernmost part of the Central Graben, where wells from the late 1970s demonstrated the presence of non-commercial amounts of hydrocarbons, but which may be possible to upgraded using modern technology. The depth to the top of the chalk in these structures is about 1700 m. Andersen *et al.* (2015) estimated the total non-risk weighted P50 volume to be 223 million m^3oe (45 million m^3oe, risk weighted). GEUS considers it probable that future seismic studies may identify additional stratigraphic leads in the chalk with total non-risk weighted present amounts of 25 Sm^3 in the Central Graben or possibly on the adjacent parts of the Ringkøbing Fyn High. It should be noted that there is a large spread in the size distribution of fields, prospects and leads.

9. Palaeogene sandstone oil / gas play

Paleocene and lower Eocene sandstones at a depth of 1800–2200 m are reservoirs in oil-producing fields located in the Siri Canyon on the southern flank of the Norwegian-Danish Basin (Figures 2, 3). Oil was also found in Palaeogene sandstone in 2010 with the Solsort discovery made in the north-eastern part of the Central Graben at a depth of approximately 3000 m. No production from the Solsort has been made but it is expected to commence in the near future. The known reservoirs all belong to a system of deep marine turbidite sandstone bodies in the Siri Canyon, which is one of several canyons that cuts the top Chalk Group surface east of the Central Graben. The traps, which mainly include classic 4-way closures formed by differential compaction, are filled by long-distance migration (up to 70 km) of oil sourced from the mature Farsund source rock in the Central Graben (Schovsbo *et al.*, 2020). The Solsort discovery was made on a combined structural and stratigraphic trap east of the Svend field on the western extension of the Siri trend (Figure 2).

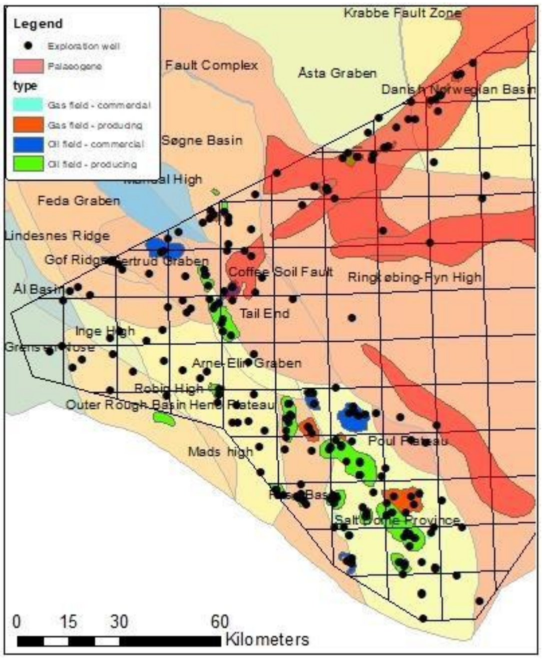

Figure 12: Paleogene sandstone oil / gas play map.

The Siri trend along the Danish-Norwegian border and the adjacent part of the Central Graben has reached a very mature exploration stage, where only a few and small further discoveries can be expected. At the same time, no Paleocene reservoir intervals have been found in the very large number of wells in the Central Graben, which drill this stratigraphic interval. Five dry wells without a sand reservoir have been drilled in the chalk on the Ringkøbing-Fyn High (Figure 12). However, it is too early to conclude that there is a definitive negative test of the play in these areas. However, there is a significant exploration risk associated with both the presence of the reservoir and the migration route on the Ringkøbing Fyn High. The inventory of possible resources includes small discoveries in the Siri trend (eg. the Rau discovery), where the license has been returned due to sub-commercial quantities. In addition, in the Siri area, gas has been detected in small amounts within Oligocene turbidite sandstone. Potential gas resources in this play have not included. In summary Andersen *et al.* (2015) estimated that a total non-risk weighted P50 volume of 3 million m^{3}oe could be present in the Siri Canyon trend.

10. Neogene sandstone oil / gas play

Interest in possible resources within the Neogene has increased with the discovery of oil in Miocene sandstones in the exploration well Little John-1 drilled on the flanks of the John Salt diapir in the southernmost part of the Central Graben (Figures 1, 3). This discovery is now producing (Goffey *et al.*, 2018).

The presence of hydrocarbons in the shallow layers over salt diapirs has traditionally been perceived as a 'drilling hazard' in connection with exploration of the underlying chalk. It is thus worth noting that the T-1 well drilled on the Svend field in the 1970s detected oil in Miocene sand that later shown linked to a seismic bright spot. It is therefore possible that other 'drilling hazards' close to existing fields may switch to prospects as seen from DHI maps (i.e. Figure 14) as this indicate that leaking hydrocarbons from underlying layers are commonly associated with the oil and gas fields in the Danish Central Graben. Also, seismic 'bright spots' are also very common in the Neogene east of the Central Graben (Figure 14). Here it is, however, much more uncertain whether it represent gas of thermogenic or biogenic origin not to mention if it exists in producible quantities.

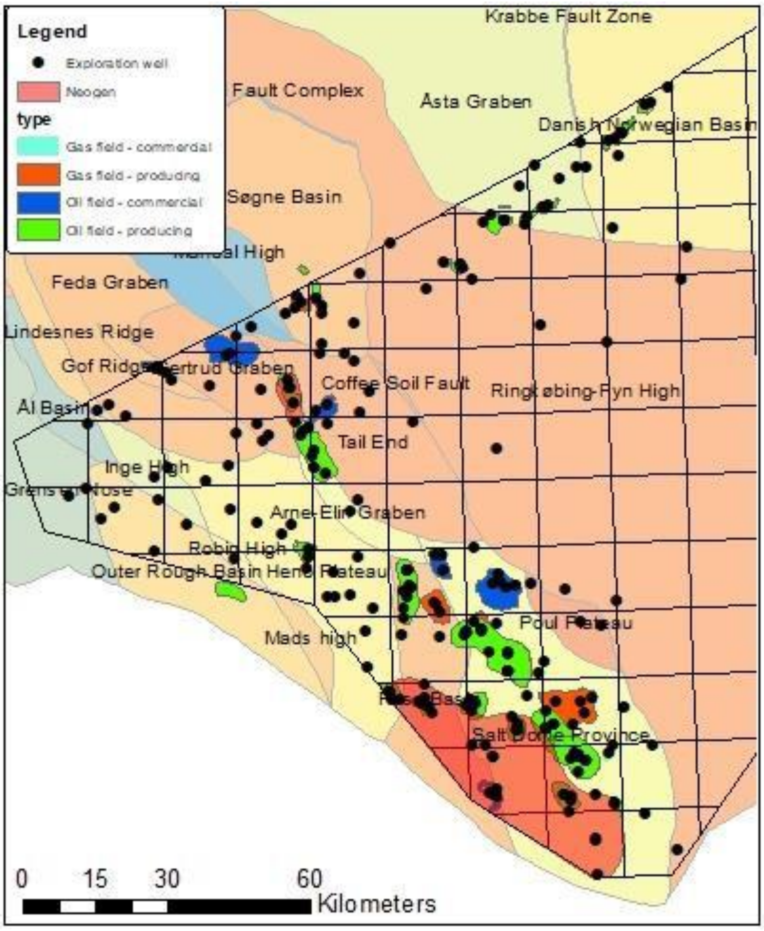

Figure 13: Neogene sandstone oil / gas play map.

In addition to the area around the Svend field in the north, the play area in Figure 13 is limited to the southwestern most part of the Central Graben in the John area, where sand is expected to occur in units of late Miocene age. In addition, oil traces have been found in several wells in connection with salt structures. Five shallow prospects and leads less than 1500 m deep have been included in the inventory, of which 3 occur over salt structures. Andersen *et al.* (2015) estimated that the total non-risk weighted P50 volume to be 65 million m^3oe (18 million m^3oe, risk weighted). This estimate does not, however, include other areas with seismic DHIs (c.f. Figure 14) that may represent shallow gas accumulations.

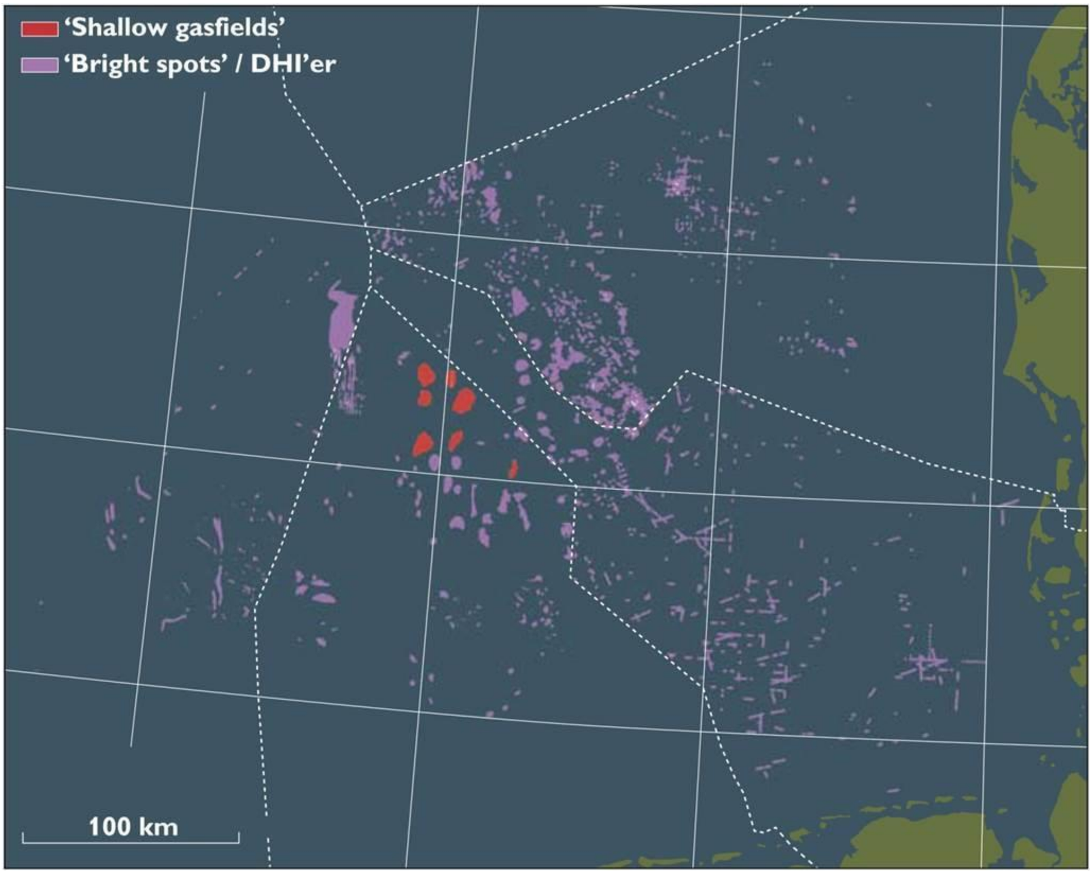

Figure 14: Bright spots (DHI). From the Southern Permian Basin Atlas (SPBA).

11. Pre-Jurassic plays

Pre-Jurassic plays all depend on the uncertain presence of deep-lying and gas-forming carbonaceous rocks of Carboniferous age. Possible reservoirs can be found both in the Triassic (Bunter sandstone and in the Skagerrak Formation) and in the Permian (Rotliegend sandstone). So far, no discoveries related to such plays have been made in the Danish North Sea. This contrasts with the southern North Sea, where thick organic rich Carboniferous units are the source to the gas in the southern gas province. The distribution of possible source rocks is, however, largely unknown in the Danish Central Graben. Coals of lower Carboniferous age are known only from a single well on the Gert structure. However, the source of the Paleozoic reservoirs on the nearby A6-B4 gas field in Germany is most likely carbonaceous deposits in the Scremerston Formation of Carboniferous age. This suggests that similar layers may be preserved in the deeper buried parts of the Danish Central Graben east of this. Outside the Central Graben, potential deep-lying gas can also form but is highly uncertain and no assessment of resources is made.

Andersen *et al.* (2015) estimated a limited risk weight resource to be present within this play (4 million m^3oe, risk weighted) distributed to 4 prospects and leads.

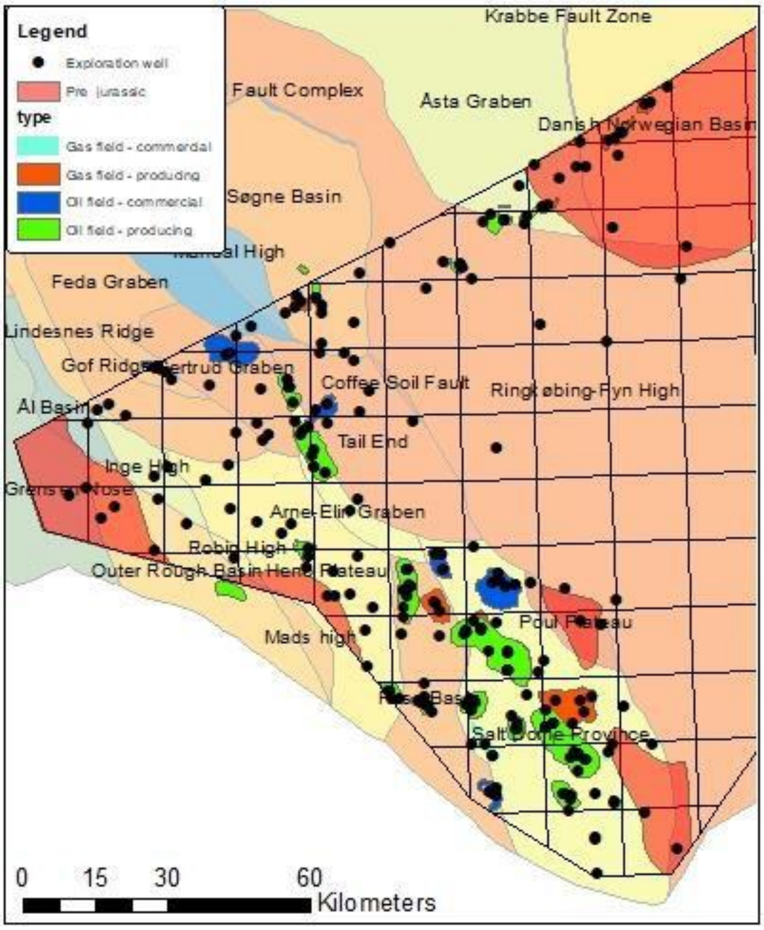

Figure 15: Pre-Jurassic play map.

12. Unconventional plays – Farsund Formation

The main source rock in the Central Graben is the organic-rich Upper Jurassic Farsund Formation, which is present in most of the area. The formation may have an exploration potential, as there has been produced oil from it in some wells. An example is the drilling Jens-1 from 1982 where a 60-foot strongly fractured zone of shale and thin dolomite layers was tested with a production rate of around 1200 BOPD. On the current basis, it is not possible to quantify the potential but only to give a calculation example. In connection with a production well on the Valdemar field, a horizontal well track in the Farsund Formation was planned to test the production potential. At the same time, the operator carried out an 'up-side' estimate of around 1.5 billion m^3 for the oil volumes present for the upper approximately 700 m of the formation covering an area of approximately 50 km^2 with assumptions about both fracture and matrix porosity. It is noted that the area covers only a small part of the total volume of the formation. However, only insignificant amounts were produced in the well track VA-5b, after which the well track was closed with the conclusion that the production potential in the investigated interval here was very limited.

More recently, a growing interest has been seen for unconventional hydrocarbon resources within the Jurassic shales in the DCG (Galluccio *et al.*, 2019). Efforts to map and quantify the resources in the Central Graben have begun as part of the project Geological Analysis and Resource Assessment of selected Hydrocarbon systems (GARAH). The mapping will quantify the hydrocarbon present with the matrix of the oil and gas mature areas of the DCG (Figure 16) where this play is present.

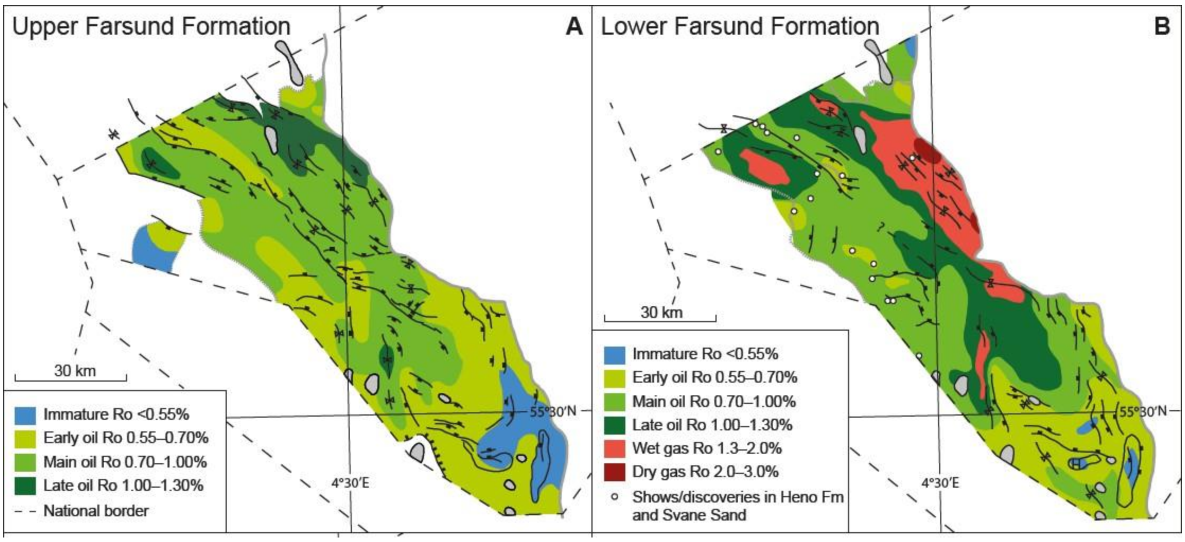

Figure 16: Maturity of the top and base Farsund Formation. From Schovsbo et al. (2020).

Summary

The 12 play maps in the Danish Central Graben originally presented by Andersen *et al.* (2015) range from the well-established Upper Cretaceous chalk play to unproved plays within the Farsund Formation and the newly established Heno Formation and Neogene plays. For each play the resource was estimated based on evaluation of 21 discoveries and 72 prospects and leads. Within the discovery portfolio Andersen *et al.* (2015) estimated an addition resource of 246 million m^{3}oe to be present in the Danish Central Graben and an additional 190 million m^{3}oe (risked) to be present within the yet-to-find category. The summed P50 values for quantities present (in million m^{3}oe) of the individual prospects and leads (categories 2 and 3) within the described play types are summarized in Table 1. It is noted that play no. 6, 8 and 11 (upper Farsund, Outer Rough and pre-Jurassic) are still unconfirmed. In the analysis of Andersen *et al.* (2015) the summed P50 non-risk weighted amounts of these make up about 30% of the total, but only about 20% of the risk weighted total, reflecting the increased play risk. The table also includes possible additional resources related to yet unidentified and mapped leads.

It should be noted that the chosen inventory method by Andersen *et al.* (2015) is based on a summation of the prospects and lead portfolio known by GEUS. Possible un-mapped additional resources linked to the confirmed plays will probably provide a likely upside to the total 'yet to find' quantities present in Table 1. Also, no attempt was made to quantify possible resources associated with fractured shale (tight oil) in the Farsund Formation or within the matrix itself, just as new data may increase the potential in shallow Neogene reservoirs.

In the ongoing GARAH project the assessment method will be revaluated including the risk approach. Also attempts to quantify the possible resources in the Farsund Formation will be made.

		Category 1 (mil m^3oe)		Category 2+3 (mil m^3oe)		
	Play type	Discoveries	P50	Prospects and leads	P50 (non-risked)	P50 (risked)
1	Neogene	1	10	5	65	18
2	Paleogene	3	21	2	3	0
3	Upper Cretaceous (Tor, Ekofisk Formations)			12	223 (+25)	45 (+2.2)
4	Upper Cretaceous (Hidra, Kraka Formations)	4	25	4	41	4
5	Lower Cretaceous (Tuxen – Sola Formations)	1	29	3	41	19
6	Upper Jura (Upper Far-sund sst)			9	189	30
7	Upper Jura (Intra Farsund sst)	1	44	4	81 (+20)	27 (+2)
8	Upper Jura (Outer Rough sst)			3	44	7
9	Upper Jura (Heno Formation)	6	78	15	102	21
10	Mid Jurassic sandstone	5	39	11	38 (+15)	9 (+1.5)
11	Pre-Jurassic			4	30	4
	Total	21	246	72	857 (+60)	184 (+5.7)

Table 1: Summary of estimated resource for category 1 and "yet to find" (category 2 + 3) for the individual plays for P50 (non-risk weighted and risk weighted) as well as the estimated possible as yet unidentified additional resources (in parentheses). From Andersen et al. (2015).

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