Geological Analysis and Resource Assessment of selected Hydrocarbon systems

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Deliverable

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Updated assessment of the conventional and unconventional resources of the North Sea Basin

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ABSTRACT

The Geological Analysis and Resource Assessment of selected Hydrocarbon systems (GARAH) work package 2 overall aim is to assess and evaluate hydrocarbon (HC) resources across borders in the North Sea. The assessment of the conventional resources is made quantitatively based on a harmonisation of the national reserve and resource estimation, and qualitatively following a play-based approach. The assessment of the unconventional resources is made following a Monte Carlo simulation approach known as the “EUOGA method”.

For conventional hydrocarbons, 14 billion cubic meters (14 x 10^9 m^3) of oil equivalent have been produced in the North Sea since the 1960’s, and additional reserves (2P) of at least 2.9 billion cubic metres (2.8 x 10^9 m^3) of oil equivalent (o.e.) are reported across the study area. Contingent resources (2C) of at least 1.5 x 10^9 m^3 have been estimated by the national agencies to be present. In addition, prospective or *yet-to-find* conventional resources of 1.9 x 10^9 m^3 o.e. are estimated combined across the study area.

Ten potentially prolific unconventional oil plays in the North Sea have been identified with a *yet-to-find* resource potential (P50) of 6.6 x 10^9 m^3 oil, and nine gas plays have a *yet-to-find* resource potential of 9,344 x 10^9 m^3 gas. This assessment includes the unconventional resource estimated for a 100 m thick Upper Jurassic to lowermost Cretaceous shale unit and thus excludes the resource base calculated in the >1 km thick shale interval in UK and Norway. The unconventional oil resource is mostly located in the Upper Jurassic- lowermost Cretaceous shales in the UK and Norwegian part of the North Sea owing to its vast regional coverage and thickness. The gas resource is dually distributed in the Carboniferous Bowland equivalent shales located in the Netherlands and in the UK offshore area and in Jurassic shales in UK and in Norway.

EXTENDED ABSTRACT

The Geological Analysis and Resource Assessment of selected Hydrocarbon systems (GARAH) overall aim is to assess and evaluate the hydrocarbon (HC) resources across borders in the North Sea. The assessment of the conventional resources is made quantitatively based on a harmonisation of the national reserve and resource estimations and qualitatively following a play-based approach. In addition, the assessment of the unconventional resources is made following a Monte Carlo simulation approach known as the “EUOGA method”.

The harmonization of the national conventional assessments shows that more than 14 billion cubic meter oil equivalents have been produced in the North Sea and that significant additional reserves and resources remain. The reserves amount to at least 2,900 x 10^6 m^3 o.e. and the contingent resources (2C) are estimated to be at least 1,500 x 10^6 m^3. Following the national agencies, it is estimated that the prospective *yet-to-find* resources are 1,900 x 10^6 m^3 o.e.

The qualitative assessment of the North Sea has resulted in the reconstruction of a total of 13 major conventional play maps that represent the first North Sea-wide mapping of the where hydrocarbon accumulations are likely to be located. The maps thus represent a major step in planning of the future use of the North Sea subsurface both in terms of licences rounds, alternative use and risking.

The assessment of the *yet-to-find* resource associated with the unconventional plays in the North Sea focus on the shale plays reflecting four main stratigraphical levels (Carboniferous, Triassic, Lower and Upper Jurassic) that have been identified to potentially hold unconventional HC resources in the North Sea area. Stratigraphical equivalent shale layers have been the main targets of onshore unconventional hydrocarbon exploration activities for more than a decade, and although similar rocks are present beneath parts of the North Sea, exploration activity offshore is restricted to a few well tests in the Danish part of the North Sea.

The assessment of the unconventional *yet-to-find* resource potential show that there is a significant resource also within the unconventional plays. The ten potentially prolific oil plays in the North Sea have identified with a *yet-to-find* resource potential (P50) of 6,648 x 10^6 m^3 oil and nine gas plays have a gas *yet-to-find* resource potential of 9,344 x 10^9 m^3 gas. This estimate includes the resource estimated for a 100 m thick Upper Jurassic - lowermost Cretaceous shale unit and thus excludes the resource base calculated in the >1 km thick shale interval in UK and Norway. The oil resource is mostly located in the Upper Jurassic- lowermost Cretaceous shales in the UK and Norwegian part of the North Sea owing to its vast regional coverage and thickness. The gas resource is dually distributed in the Carboniferous Bowland equivalent shales located in the Netherlands and in the UK offshore area and in Jurassic shales in UK and in Norway.

The unconventional resource estimate is based on Monte Carlo simulations. The main parameters that contribute to the uncertainties are the saturation, porosity and thickness and the sorption parameters such as the *Langmuir Volume* (L_V).

Since the inception of the GARAH project around 2018, the position of hydrocarbon use (and fossil fuels in general) has rapidly changed with regards to the European and national energy research agendas. This is exemplified with the latest report from the International Energy Agency (IEA) that details a roadmap to zero emission in 2050 in which new hydrocarbon exploration or development is not included (IEA, 2021). Instead, EIA argues that known HC resources will be sufficient to transition to green energy sources. Also, in the Danish part of the North Sea the current legislation has given a cut-off of oil and gas production with 2050 and does not permit new licencing rounds.

In this context, the reported total resource base, and especially the new unconventional resource estimate, may extend field life and postpone abandonment phase as the unconventional plays occur typically where production is already taking place. Understanding the current and potential resource may also support the shift from coal to domestic gas and should feed into planning and policy (particularly licensing of areas for exploration) by Member States, as well as commercial exploration strategies. Lastly, our mapping of remaining knowledge gaps can inform any academic research or programs of exploration sponsored by member states. The combined assessment of the resource base also has value for decarbonising energy in the subsurface of North Sea, with potential for providing carbon and other energy storage and production (e.g. blue hydrogen).

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1 INTRODUCTION

Within the context of the project "Geological Analysis and Resource Assessment of selected Hydrocarbon systems (GARAH)" hydrocarbon resources are assessed and evaluated in the North Sea that represent Europe's most prolific petroleum basin. The North Sea is set to play a major role in the future energy direction (including decarbonisation, Quirk et al., 2021) of neighbouring countries, underpinned by its natural resources (including oil and gas), renewable energy asset (principally wind and solar, but also tidal), and geography.

This report (D2.3) follows the progress of Task 2C in the GARAH project and concentrates on the resource assessment of the unconventional as well as conventional hydrocarbons in the North Sea basin. Collected data on the hydrocarbon resources from Tasks 2A and 2B reported in GARAH Delivery Reports 2.1 and 2.2 are used in the assessment (Table 1-1). GARAH also investigates the multiple-use (or sequential-use) potential and impacts of hydrocarbon reservoirs that will enable the European community to improve efficient, sustainable, and foster climate friendly use of the subsurface. This will be reported in GARAH Delivery Report 2.6.

One of the main outcomes of Task 2C is to present the first North Sea basin wide assessment of the *yet-to-find*[1] unconventional shale gas and oil resources. For this we use the "EUOGA" method, culminating in a probabilistic volumetric calculation of the GIIP/OIIP with P10, P50 and P90 assessments and an uncertainty evaluation as well as a general chance of success description. The Task 2C also include an updated assessment of the conventional resources made on data from previously performed assessments at the respective national energy agencies and a comparison to the *yet-to-find* resource made as part of the 3DGEO pilot area as reported in the GARAH Deliverable Report 2.4 and 2.5 (Table 1-1).

Table 1-1 GARAH WP2 deliveries related to hydrocarbon assessment of the North Sea

<table>
<tr><th>Deliverable number</th><th>Task</th><th>Deliverable name</th></tr>
<tr><td>D2.1</td><td>2A</td><td>Data base and harmonization report</td></tr>
<tr><td>D2.2</td><td>2B</td><td>Petroleum system report and GIS maps in North Sea</td></tr>
<tr><td>D2.3</td><td>2C</td><td>Updated resource assessment in the North Sea</td></tr>
<tr><td rowspan="2">D2.4</td><td rowspan="4">2D</td><td>Resource assessment 3D pilot area</td></tr>
<tr><td>Unconventional</td></tr>
<tr><td rowspan="2">D2.5</td><td>Resource assessment 3D pilot area</td></tr>
<tr><td>Conventional</td></tr>
<tr><td>D2.6</td><td>2E</td><td>Hazards and Alternative use</td></tr>
</table>

[1] Accumulations that have yet to be discovered

1.1 Conventional

For the assessment of the conventional resources in the North Sea a two-step approach was followed. A quantitative assessment was made based on published information and reports from the respective countries. These were collected and the applied methods compared (see GARAH Deliverable Report 2.1 and 2.2). A qualitative assessment was made from harmonizing play maps across the North Sea. In this step, plays that were not included in the published assessments were identified, and collated to reveal cross-border issues. All plays were then classified into different categories, based on their assessment status as well as their maturity (mature, proven, new, conceptual). Finally, the published resource assessments were harmonized in terms of units and collated to cover the North Sea study area.

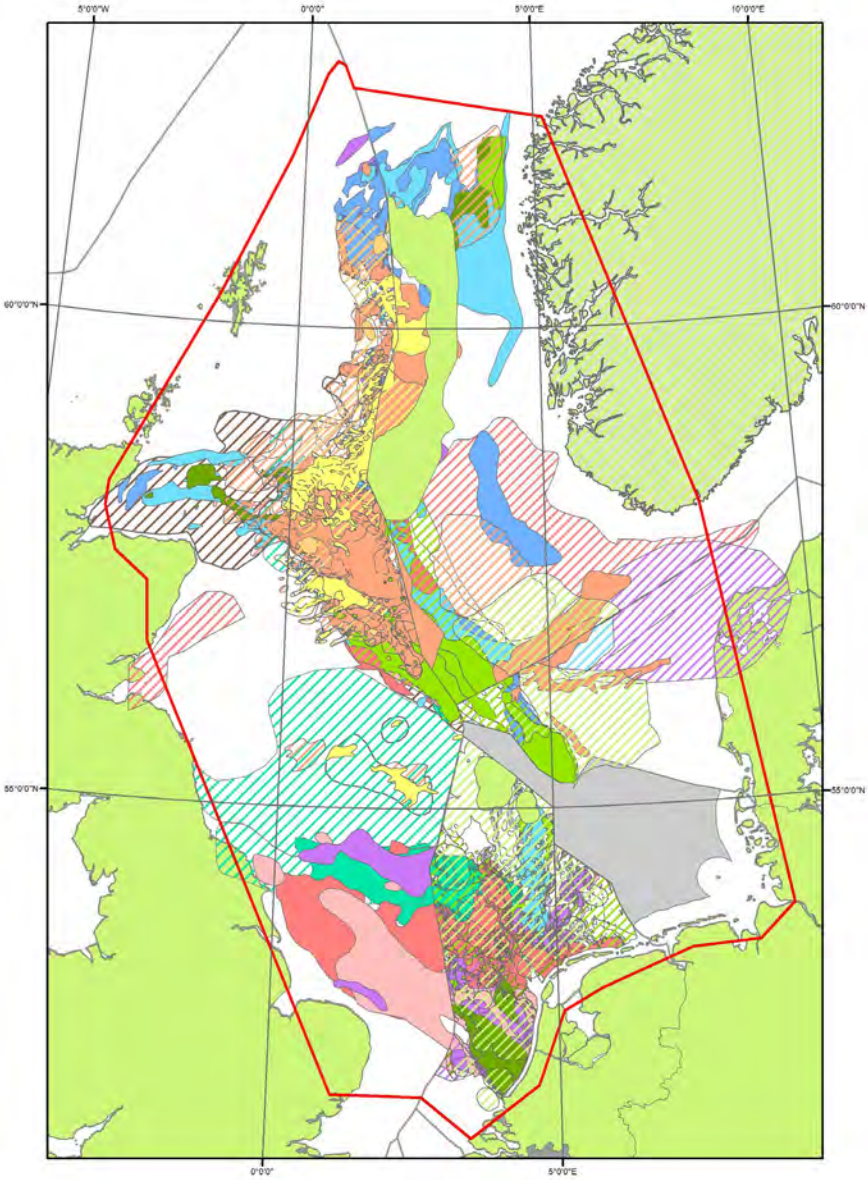

Figure 1-1 The GARAH North Sea study area (red outlines) and all harmonised conventional play outlines in GARAH GIS. Updated from GARAH Deliverable Report 2.2.

1.2 Unconventional

The assessment of the unconventional *yet-to-find* resource in the North Sea Basin is made as an extension of the mapping and assessment of European onshore unconventional resources made within the framework of the EU funded European Unconventional Oil and Gas Assessment (EUOGA) project completed in 2017 (cf. Anthonsen et al., 2016; Nelskamp, 2017; Schovsbo et al., 2017; Zijp et al., 2017). One outcome of the EUOGA project was the formulation of a scientifically based assessment methodology aimed to provide a consistent appraisal of this new resource base that can be used by relevant policy makers and society. In the GARAH project we have followed the EUOGA established method with minor modifications for adaption to the North Sea offshore play setting.

The North Sea unconventional shale plays in the GARAH study area were identified and reported within the GARAH Deliverable Report 2.2. In this report the nine identified gas and ten oil plays were assessed (Figure 1-2). The plays are identified within 12 well-known source rock strata, including the Upper Jurassic to lowermost Cretaceous shales: i.e. the Kimmeridge Clay Formation in the UK, the Farsund Formation in Denmark and Germany, and the Mandal Formation in Norway, the Lower Jurassic Posidonia shale in the Netherlands, Germany and the UK, the Triassic Sleen Formation in Germany, the marine Carboniferous Bowland equivalent shales from UK and the Geverik Formation from the Netherland (for stratigraphical overview see Figure 3-8).

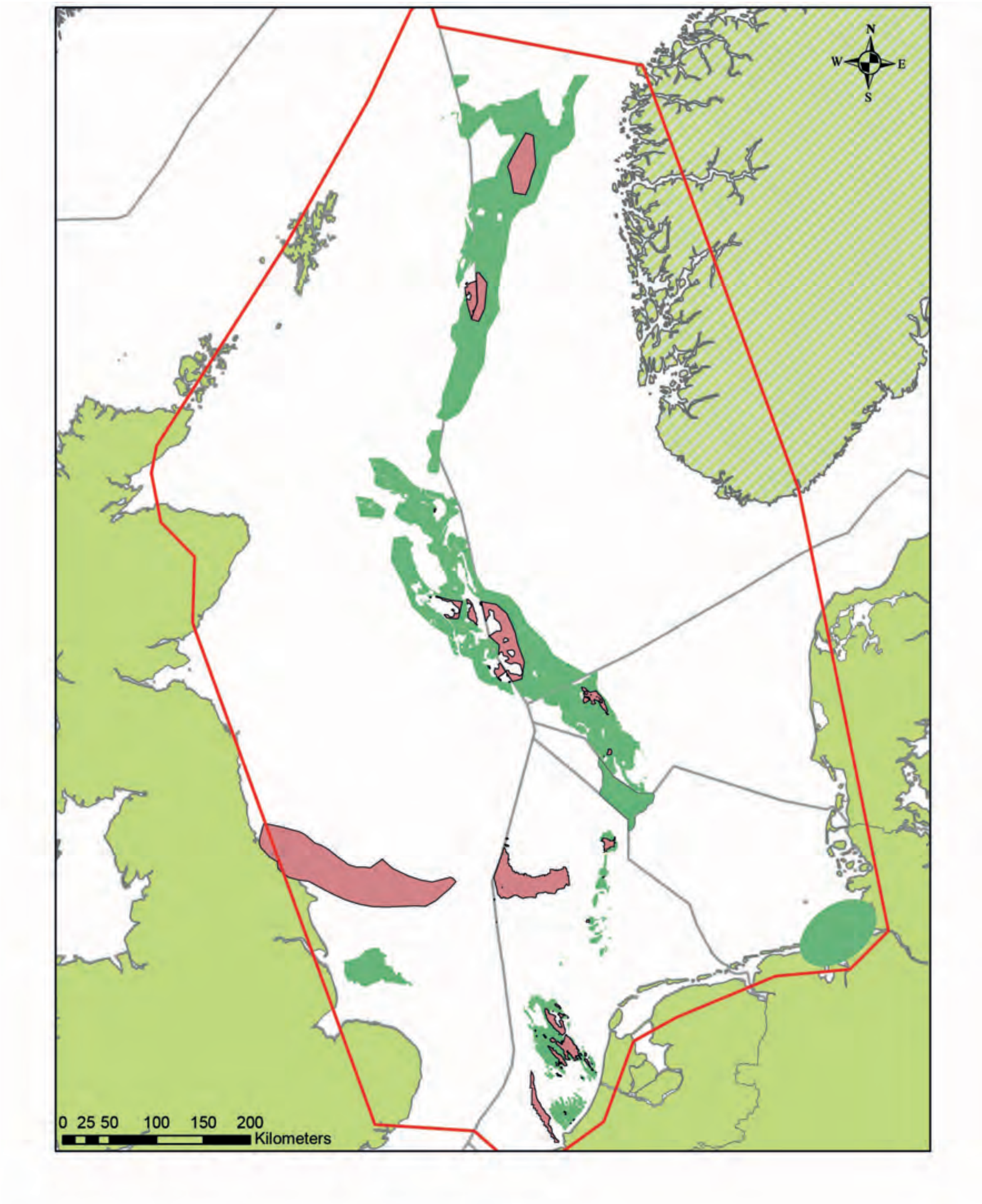

Figure 1-2 The GARAH North Sea study area (red outlines) and occurrence of the identified shale play (10 oil plays marked with green, and 9 gas plays marked with red) outlines in the unconventional GARAH GIS. From GARAH Deliverable Report 2.2. Note that some plays may be hidden below others.

Offshore unconventional development – technical feasibility

Currently, there are no unconventional hydrocarbon exploration or developments ongoing in the North Sea Basin. In the scientific literature, however, several descriptions of potential unconventional sweet spots within the North Sea Basin have been reported. Cornford et al. (2014) describe a tight sand-shale system within the Upper Jurassic sequence and Galluccio et al. (2019) proposed that dolomite stringers, which typically occur in the Farsund Formation, could act as an unconventional reservoir in a manner that compares to the Bakken oil shale play in North Dakota, U.S., where wells are completed within a tight limestone bed interbedded in an oil mature shale (c.f. Jarvie, 2012a, b; Zhau et al., 2021). Both descriptions thus suggest that geological similarities to producing North American unconventional plays exist in the North Sea Basin.

In the North Sea, unconventional field development would, however, be fundamentally different from any onshore unconventional development due to differences in economics and logistics between on- and offshore. However, it is envisioned that the technical part of the development of an unconventional resource could be quite similar to producing North American shale fields, e.g. applying long horizontal multistage fractured wells but from offshore platforms. A blueprint for such an offshore development of shale plays could be the producing chalk fields in the Danish North Sea, where from a single pad a subsurface reservoir area of more 30 km^2 has been developed (c.f. Figure 1-3).

An alternative to this would be the exploitation of offshore (near-shore) resource from well pads located onshore; this has the benefit of lower drilling costs and the possibility of a reduced impact to onshore stakeholders. Hence, from a technical point of view an offshore development of shale plays in the North Sea seems feasible.

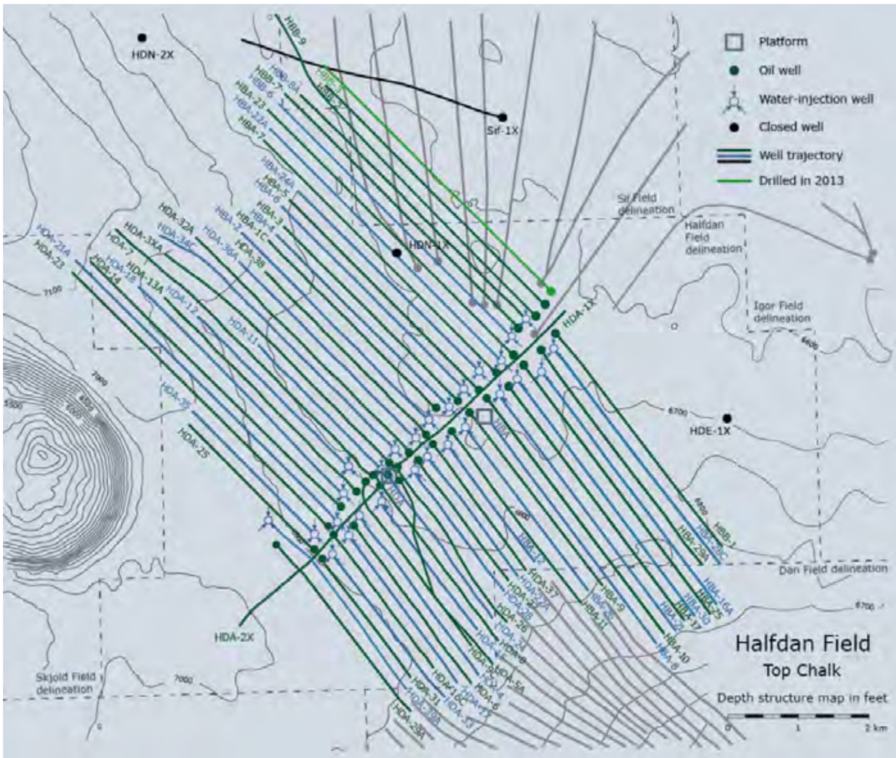

Figure 1-3 Well schematics for the Halfdan chalk field in the Danish North Sea (DEA, 2013). The field may serve as a technical analogue for offshore shale play development using horizontal drilling and multistage fracturing as already done in some North Sea chalk fields. The subsurface coverage is about 32 km^2 from two platforms.

2 METHODOLOGY

2.1 Conventional Methodologies

2.1.1 Resource Assessment Methodology

Most of the countries in the North Sea Basin study area regularly publish updates of their conventional hydrocarbon resource assessments (see also Section 2.1 of GARAH Deliverable Report 2.2). For the purpose of this study, the assessments from Germany (DE), Denmark (DK), Norway (NK), the Netherlands (NL) and the United Kingdom (UK) were collected, and a comparison made of their general methodologies, published resource assessments and potential or *yet-to-find* hydrocarbon resources. Numbers are reported in the format 10^6 for millions and 10^9 for billions in general.

All public resource assessments in the study area use the PRMS method based on updated from the Society of Petroleum Engineers (SPE, 2018) for the classification and assessment of their hydrocarbon resources (Figure 2-1). The Norwegian Petroleum Directorate (NPD) publishes their assessment methodology in their yearly report and describe how it translates to the PRMS system as shown in Figure 2-2.

In this report, we attempt to collate, compare, and, where possible, combine these assessments within the GARAH study area of the North Sea. As different countries publish resource estimates using different units, in this report, we attempt to harmonise published resources by converting final resource assessments into standard cubic metres (Sm^3) oil equivalent where possible. Generally, converted figures are rounded to the nearest million. In some examples, conversion has already been carried out within published data; in these cases, the authors will indicate that the conversion comes from the original source. In other cases, the GARAH authors have converted the resources using the conversion unit factors from Norwegian Petroleum Directorate (NPD) statement on conversion of units (NPD, 2021).

To convert volumes to weights and vice versa requires assumptions regarding temperature and pressure; the NPD assume standard conditions of 15 °C and normal atmospheric pressure (101.325 kPa). Resources and reserves are also sometimes converted to oil equivalent (o.e), in order to account for varying types of petroleum products (oil, gas, and condensate). NPD conversions are based on average properties for the Norwegian shelf, and so conversions for the North Sea GARAH area of interest are not considered to be exact. Where conversions have been carried out to harmonise cross-border resource assessments, this is noted in the appropriate text or caption. Table 2-1 provides the list of conversion factors and units used by NPD as of September 2021.

Table 2-1 List of conversion factors and units from the NPD conversion calculator and website (NPD, 2021). Nm^3 reference conditions are 0 °C and 101.325 kPa. Sm^3 reference conditions are at 15 °C and 101.325 kPa.

1 Sm^3 oil	=	1.0 Sm^3 o.e.
1 Sm^3 condensate	≈	1.0 Sm^3 o.e.
1000 Sm^3 gas	≈	1.0 Sm^3 o.e.
1 Sm^3 NGL	≈	1.0 Sm^3 o.e.
1 tonne NGL	≈	1.9 Sm^3 o.e.
1 Sm^3	≈	35.315 SCF
1 SCF	≈	0.028317 Sm^3
1 Sm^3	≈	6.2898 barrels
1 Sm^3	≈	0.84 t o.e.
1 Sm^3	=	0.9475 Nm^3

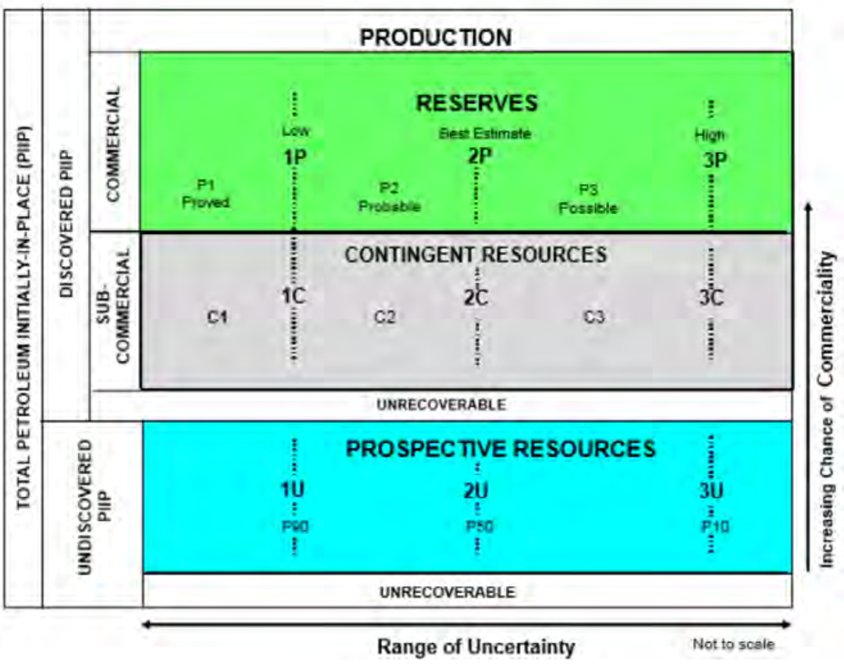

Figure 2-1 Classification used for Total Petroleum Initially in Place (PIIP). From (SPE 2018).

In addition, details of hydrocarbon plays were compiled and compared across borders (see GARAH Deliverable Report 2.2 for lists and methodology). For each country these plays were given a status (conceptual, new, proven, mature) based on their exploration and production status, the amount of data available for the play and the known discovered fields. Differences in the assessment of these plays are highlighted in Section 3.2 and discussed in Section 4.2.

2.1.1.1 Resource Assessment Methodology: DE

In Germany the reported reserves and resources follow the international Standard SPE/WPC (1997), UN/ECE 1996 as reported in Porth et al. (1997). Only production data is publicly available, and there is no differentiation between the onshore and offshore.

2.1.1.2 Resource Assessment Methodology: DK

The Danish Anergy Agency (DEA) makes an assessment of Danish oil and gas resources. A description of the classification system is given below with the GARAH correlatrive PRMS resource class in brackes.

Reserves (2P)
The category include ongoing recovery and approved for development.

Contingent resources:

Technology dependant (3P)
The DEA has reviewed a number of options for increasing the recovery with the use of known technology, i.e. technology that is used today under conditions comparable to those prevailing in the North Sea. Based on reservoir calculations and general estimates of investments, operating costs and oil price developments, it is assessed that it is possible to recover additional oil and gas from a number of fields.

Pending development (2C)
Resource category dependant of further recovery from the Fields Adda, Alma, Amalie, Boje area, Elly, Freja, Gorm, Halfdan, Tyra and Valdemar is included.

Development unclarified (3C)
The category development unclarified comprises additional recovery from the fields Halfdan South Arne and Tyra.

Development not viable or on hold
Includes resources in discoveries not considered commercially viable under the existing conditions

2.1.1.3 Resource Assessment Methodology: NL

Petroleum reserves and Contingent resources

The advisory group for the Ministry of Economic Affairs and Climate at TNO publishes annually a report on Natural resources and geothermal energy on www.nlog.nl. The oil and natural gas report follows the PRMS classification and focusses on probable reserves class (2P) and the first subclass of the contingent resources (2C) (Development Pending).

Gas volumes are reported in standard cubic meters (Nm^3) using the standard reference conditions of 0^oC and 101.325 kPa where $1Nm^3 = 0.9475\ Sm^3$. In some cases the gas volumes are reported as Groningen gas equivalent (m^3 Geq) of 35.17 MJ gross calorific value per Nm^3. One Nm^3 gas with a calorific value of 36.5 MJ is equivalent to 36.5/35.17 Nm^3 Geq. Oil volumes are reported in standard cubic meters (Sm^3) with reference conditions of 15^oC and 101.325 kPa.

Prospective resources

The following text is mostly quoted and slightly modified from the annual report on Natural resources and geothermal energy (2018) on www.nlog.nl.

Exploration potential

TNO updates the Dutch prospect portfolio for natural gas based on data that operators provide in their annual reports for their licensed areas in accordance with Article 113 of the Mining Decree and in accordance with the PRMS directive.

TNO assumes a fixed number of prospect developments (i.e. exploration wells) per year in the evaluation. The number of exploration wells occurring each year is based on the long-term moving average (5 years) of historical exploration drilling intensity, which corresponds to 5 offshore and 2 onshore wells. The choice to base the drilling intensity in the evaluation on historical figures does mean that the current low oil and gas price does result in a large decrease in drilling intensity. The exploration potential figures presented are therefore representative on long time scales (~25 years).

Geological units and prospects

TNO focuses on the evaluation of the so-called ‘proven plays’. These are geological units for which the data and discoveries justify the assumption that the necessary geological conditions for the generation, migration and accumulation of natural gas took placed. Together, all prospective structures (‘prospects’) that have been mapped and evaluated on the basis of existing data form the prospect portfolio.

Hypothetical plays and prospects are ignored, due to their speculative character. Both TNO and EBN have noticed that in the majority of prospect developments the predrill volume of gas in place are overestimated. On average, only half of the expected volume was found. This implies that any volumes presented as a result of the exploration potential in this annual report may be deemed optimistic. However, TNO does not take into account prospects in non-proven plays or as yet unidentified prospects, thus the exploration potential will be conservative.

Gas portfolio characteristics
The prospect portfolio is characterised by the number of prospects and the associated volume of gas. The volume of a prospect can be expressed either in terms of the expected recoverable volume in the case of a discovery (the so-called Mean Success Volume, MSV), or as the risked volume (the so-called Expectation volume, EXP). The expectation volume is the product of the MSV and the probability of finding natural gas (the Possibility of Success: POS).

Exploration potential
The exploration potential is that part of the prospect portfolio that meets certain minimum economic conditions. This economic threshold is based on (amongst others) the annual number of exploration wells (i.e. number of prospects drilled), the expected gas price, the spatial distribution and availability of infrastructure, the expected volumes, productivity and the spatial distribution of the prospects.
"…" The exploration potential is defined by two methodologies which quantify the economical attractiveness of the portfolio, the Expected Monetary Value and Risked Value to Investment Ratio."

Ministry of Economic Affairs and Climate Policy (2018) Natural resources and geothermal energy in the Netherlands – Annual review 2017. https://www.nlog.nl/sites/default/files/yearbook%202017-%20englishversion.pdf

2.1.1.4 Resource Assessment Methodology: NK
In Norway, the Norwegian Petroleum Directorate (NPD) has developed its own resource and reserve classification system that has been compared to other international systems such as the UNFC-2009. This was described in the bridging document of Knudsen et al. (2015).

The NPD classification is outlined in Figure 2-2. The NPD system requires that all resource estimated must describe a low estimate, a base estimate and a high estimate. Prospective resources are classified into leads (class 8) and leads and plays (class 9). Contingent resources are classified in resources classes 4 to 7.

	NPD 2001			
		Category		*Class*
Discovered	Reserves	In production	1	Reserves
		Approved Plan for Development and Operation (PDO)	2F	
			2A	
		Licensees decided to recover	3F	
			3A	
	Contingent Resources	In the planning phase	4F	Contingent Resources
			4A	
		Recovery likely but undecided	5F	
			5A	
		Not yet evaluated additional potential	7A	
		Not yet evaluated	7F	
		Recovery not very likely	6	
Undis-covered	Undiscovered Resources	Prospect	8	Undiscovered resources
		Lead and Play	9	

Figure 2-2 NPD classification scheme. From Knudsen (2015).

2.1.1.5 Resource Assessment Methodology: UK

The oil and gas industry in the UK is regulated by the Oil and Gas Authority (OGA), who regularly calculate official assesments of the UK's reserves, resources and prospective resources. The most recent OGA report on UK offshore oil and gas reserves and resources was published in 2020 (OGA, 2020) and reports up until end 2019. A previous version was published in 2018 (OGA, 2018) and was used for the initial parts of the GARAH project.

The majority of the caculations for the UK petroleum reserves are made for the entire UK continental shelf (UKCS) and in barrels of oil equivalent (boe). Barrels of oil equivalent (boe) are calculated as below based on Appendix A of OGA (2018).

1 metric tonne of crude oil = 7.5 barrels of oil equivalent
1 cubic metre of gas = 35.315 cubic feet of gas
1 cubic foot of gas = 1/5800 barrels of oil equivalent (0.0001724)

The OGA also provides some breakdowns by area, of which the following are relevant to the GARAH project: the Northern North Sea (NNS); Central North Sea (CNS); Mid-North Sea High (MNSH) and Southern North Sea (SNS). Reserves, resources and potential resrouces are also separated by hydrcarbon type (oil, gas, dry gas, condensate). Initial harmonisation as part of the GARAH work was to convert all reported assessments into metric tonnes (for oil) and cubic metres (for gas).

The OGA seeks to align its reserves and resource classifications with those published by the Society of Petroleum Engineers (SPE) as the Petroleum Resources Management System (PRMS), as revised in 2018 (SPE, 2018).

Petroleum reserves are separated into three categories based on confidence levels and defined as: proven (1P); probable (2P); and possible (3P). Generally, this translates to: proven reserves (1P) having a 90% chance of being produced; probably reserves (2P) having a better than 50% chance of being technically and commercially producible; and possible reserves (3P) having a more than 10% but less than 50% chance of being commercially and technically possible. Further details are found in Appendix B of the OGA 2020 report. Reserves were calculated based on responses from UK operators according to the SPE classifications and as outlined in Appendix B of OGA (2020).

Contingent resources are considered as estimated petroleum recoverable from known accumulations, but not yet at the level of commercial development (see Appendix B of OGA 2020) and are classified based on confidence as: 1C (a better than 90% chance of being recoverable); 2C (better than 50% chance of being recoverable) and 3C (more than 10% but less than 50% chance of being recoverable). Contingent resources are also split into: Producing fields; Proposed New Developments; and Marginal Discoveries. Gas reserves and contingent resources are also split into field type as: dry gas; gas condensate; and gas from oil fields.

Prospective resources are defined by the OGA as "potentially recoverable resources in mapped leads and prospects that have not yet been drilled, plus those undiscovered potentially recoverable resources that are estimated to reside in plays for which there are few or mapped features" (OGA, 2020, p.21). Thus, prospective resources are separated into those which are calculated from a lead and prospect inventory, and then supplemented by additional mean prospective resources, which are estimated in plays which have not been systematically mapped with defined leads and prospects. Estimates do not include unconventional plays or onshore resources.

Significant changes were made to the methodology used to calculate *Yet-to-Find* (YTF) prospective resources in 2017/18 (OGA, 2018), in order to reflect industry best practise and to make use of the OGA inventory of leads and prospects. The new YTF estimate also includes results from the OGA's more recent programme of geological studies. Of particular interest to the GARAH project are the updated prospective resource estimates for the Mid North Sea High (MNSH) area as discussed further in Section 3.2.4.

In order to model viable targets in their approch to prospective resources, the OGA use cut-offs where leads and prospects require a minimum volume of 10 million boe (30 million for the west of Shetland area, outside of the GARAH area of interest), and have an estimated geological success rate of more than 15%, to be viable (OGA, 2018, 2020). This reduces the number of features from 3500 total to 486. Totals for resources are calculated stochasically using the Monte Carlo method rather than simply compiled arithmetically.

2.1.2 Play Methodology

Each country (expect Germany wherefrom no public play maps were available) identified hydrocarbon plays based on the definitions and methodologies described in Section 2.2.1 of the GARAH Deliverable Report 2.2. Each play was named after known productive intervals, but some more hypothetical potential plays are also included, as is reflected in the potential resource assessments for some countries (except for Germany). Further details of how plays were classified and created are detailed below.

After compilation of country play types (see GARAH Deliverable Report 2.2, Sections 2.2.1 and 2.2.2) the main plays for each country were harmonised across border in the GARAH area of interest. These are given below by age and are also used to separate the play maps in the GARAH GIS:

- Shallow Gas (generally post-Eocene)
- Eocene
- Lower Eocene
- Palaeocene
- Upper Cretaceous
- Lower Cretaceous
- Upper Jurassic
- Middle Jurassic
- Lower Jurassic
- Triassic
- Permian Rotliegend
- Permian Zechstein
- Carboniferous
- Devonian

Plays are also described as mature, proven, or conceptual, and these definitions are discussed further in the country methodologies below.

2.1.2.1 Play Methodology: DE

No publicly available information on plays are available for Germany.

2.1.2.2 Play Methodology: DK

Play maps in Denmark were recently evaluated by Schovsbo et al. (2020b) based on an older GEUS-in-house evaluation (Clausen et al., 2015 cited in Schovsbo et al., 2020b).

In Schovsbo et al. (2020b) a play is defines as a geographical area where the geological factors that are a prerequisite for generation and trapping hydrocarbons can occur simultaneous. A total of 11 conventional plays and one unconventional play were defined and each play was named by the reservoir age and hydrocarbon type present.

The plays included:

- Mid Jurassic sandstone gas / condensate play
- Upper Jurassic Kimmeridgian shallow marine sandstone oil play (Heno Formation)
- Upper Jurassic Volgian shallow water marine sandstone oil / gas play (Outer Rough sandstone)
- Intra Farsund Formation sandstone oil / gas play (Kimmeridge - lower Volgian)
- Upper Farsund Formation sandstone oil play (between Volgian - Ryazanian)
- Lower Cretaceous Chalk oil / gas play (Tuxen and Sola Formations)
- Upper Cretaceous Chalk oil / gas play (Hidra and Kraka Formations)
- Upper Cretaceous Chalk oil / gas play (Tor and Ekofisk Formations)
- Palaeogene sandstone oil / gas play
- Neogene sandstone oil / gas play
- Pre-Jurassic plays

For the purpose of GARAH project and for cross-border issues seven additional plays were defined in Denmark:

- Miocene – Diatomite - Lark Fm
- Rotliegend Sandstone
- Zechstein Carbonate
- Jurassic Sandstone
- Triassic sandstone
- Palaeogene-Neogene Sandstone - biogenic

The new plays are all conceptual and included new plays such as the Lark Fm and biogenic gas or details plays that was lumped together by Schovsbo et al. (2020b) such as the pre-Jurassic plays.

2.1.2.3 Play Methodology: NL

The play areas in the Netherlands were newly defined for the purpose of this study and a total of 16 plays were identified. The main play definitions were taken from Doornenbal et al. (2019) and are described in the GARAH Deliverable Report 2.2.

The play areas were mapped based on a stacking of the published maps of identified reservoir intervals per stratigraphic level (DGM-deep-V3, https://www.nlog.nl/en/dgm-deep-v3-offshore). These stacked reservoir maps were combined with the distribution maps of the main source rock intervals in the Netherlands (Lower Jurassic Posidonia Shale Formation – oil, www.nlog.nl, Upper Carboniferous Westphalian Coal Measures – gas, Lower Carboniferous

Coals – gas, conceptual, based on facies maps from van Buggenum & den Hartog Jager, 2007) that were extended by an average migration margin of 10 km.

Proven plays in the Dutch offshore are those that have either the Posidonia Shale Formation of the Westphalian Coal measures as their source rock interval and have at least one known field within the play outline. For some plays the play outline was subdivided based on the location of the known fields and a "proven play outline" was created based on a 10 km range around outlines of the known fields. Conceptual plays are those with the Lower Carboniferous coals as potential source rock interval and all other plays without known fields in the play outlines.

2.1.2.4 Play Methodology: NK

Play mapping was based on mapping made by the Norwegian Petroleum Directorate (NPD) - [Plays and method for calculating undiscovered petroleum resources - The Norwegian Petroleum Directorate (npd.no)).]

In Norway a play is defined as a geographically delineated area where several geological factors are present so that producible petroleum could be proven i.e. similar as the definition of plays in Denmark (c.f. Schovsbo et al., 2020b).

Plays in Norway defined by NPD include:

- Basement - fractured or weathered
- Cretaceous Chalk in Tor and Ekofisk Fms
- Middle Jurassic Sandstone
- Miocene Sandstone
- Palaeocene sandstone
- Post Palaeocene Sandstone
- Pre-Triassic plays
- Triassic, Lower-Middle Jurassic
- Upper Jurassic sandstone

For the purpose of cross-border alignment of plays, the Cretaceous Tor and Ekofisk play in Norway have been enlarged to encompass the possibility of long-distance migration of hydrocarbons from the Central Graben. This play is recognised as a hypothetical play in Denmark.

Note that a number of plays in the North Sea part of the Norwegian shelf are described as "Devonian, Carboniferous, Permian and possible Triassic" and so their age is uncertain.

2.1.2.5 Play Methodology: UK

A total of 48 plays were identified within the GARAH North Sea study area offshore the UK, with further details of their compilation published in Figure 2-2 and 2-3 of the GARAH Deliverable Report 2.2. UK play maps were compiled based on published maps of reservoir distribution (OGA and Lloyds Register, 2019) and depositional environment as well as internal BGS studies. Details on source maturity and migration were generally sourced from the Millennium Atlas (Kubala et al., 2003). Further sources for each play are included in the GIS attribute tables.

Mature plays in the UK offshore are considered those which are well understood and producing; these are associated with known fields. Proven plays may not be producing but are considered to be relatively well geologically understood and were likely included in the OGA *yet-to-find* lead and prospect inventory (see Section 2.1.1.5). Conceptual plays are based on internal BGS studies and on the 2017/18 OGA systematic estimate of play-level prospective resources, which are risked and modelled in the OGA 2020 reserve and resource report. Values for these play estimated prospective resources by area are reported in Section 3.2.5.2 and a list of Unproven plays is provided in Appendix C of OGA (2020).

2.2 Unconventional Methodologies

The unconventional resource assessment method applied here follows the methodology to assess the in-place hydrocarbon resources established during the EUOGA project (Nelskamp, 2017, Schovsbo et al., 2017 and Zijp et al., 2017) to ensure comparability with other European assessments. The method first aims at ranking individual shales in a pre-screening procedure prior to the assessment as presented in GARAH Deliverable Report 2.2.

*2.2.1 **Shale ranking***

In the EUOGA method, four shale ranks or classes were defined based on the degree of knowledge and geological similarity to producing North American shales (Table 2-2). The two highest ranking classes (Class 1 and 2 in Table 2-2) are considered to be grossly similar in terms of thermal maturity, organic richness, thickness and burial depth to producing North American shales and are characterised by numerous data. However, it is important that we here do not consider other relevant parameters such as mineralogy, in-situ stress, planning and development constraints.

Shale ranking in these two prime classes qualify to be assessed from a technical point of view. Shale plays of the lowest lower rank classes (3 and “no” in Table 2-2) either deviate widely from accepted criteria for successful plays and/or are so poorly defined that they must be considered as completely hypothetical. Therefore, resource assessments have not been conducted for these two classes of shale plays in the North Sea Basin.

Table 2-2 Shale play classification. From Nelskamp (2017).

- Class 1 – Main screening parameters consistent with typical shale gas/oil play as known from plays in the US
  - GIIP/OIIP calculation
- Class 2 – Some parameters are not consistent with typical shale gas/oil plays
  - GIIP/OIIP calculation with wider range for parameters and overall higher uncertainty
- Class 3 – Some parameters are unknown
  - GIIP/OIIP calculation only if critical parameters are available. Possible zero value in uncertainty estimation
- No – A parameter falls out of the range of shale gas/oil plays
  - no GIIP/OIIP calculation

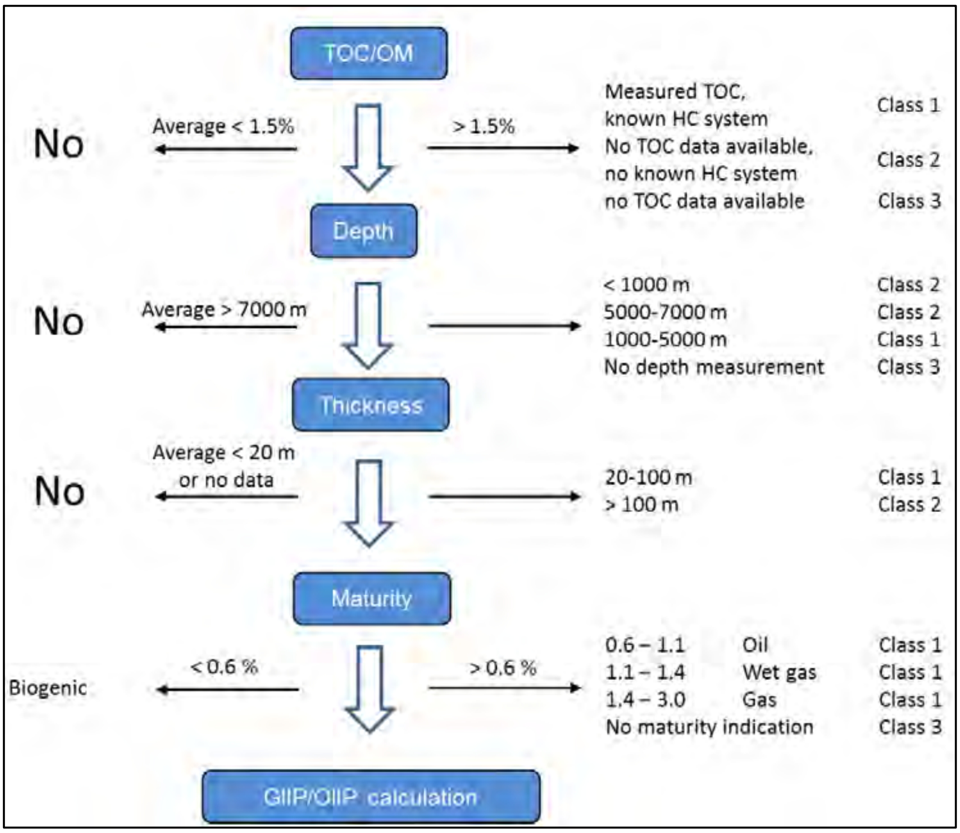

Figure 2-3 Shale play ranking and screening steps. From Nelskamp (2017).

2.2.2 Play parameters

<u>Depth</u>

For the assessment, a maximum average reservoir depth of 5 km below sea surface and a minimum depth of 1 km is used as maximum and minimum limits. Areas shallower than 1 km are thus not included. In the EUOGA project resources between 5 and 7 km were also included in the assessment (Figure 2-3). We do not, however, envision that shales deeper than 5 km will in any manner be realistic for offshore development in the North Sea. Such areas will be in a high temperature and high pressure (HPHT) regime (c.f. Schovsbo et al. (2020a) for the Danish area) where even conventional discoveries would be regarded as an extreme high risk.

Thickness

An average net shale thickness of 20 m is the lower boundary for the assessment (Figure 2-3). The resource assessment of >100 m thick shale seqeunces are made with a slight modification to EUOGA. A typical shale development will access and drain the reservoir ± 50 m around the well bore. Development of >100 m sequence can be done as in a conventional stacked reservoir system by multilateral, stacked production wells. Offshore, however, we consider such reservoir development that depend on multilateral, stacked from one vertical, drill slots unlikely. Thus, these plays were integrated into the assessment with a reservoir section limited to 100 m thickness. For comparison, however, we also calculated the in in-place resource potential using the full thickness range of the shale interval.

Maturity

The maturity information for mature plays were used to subdivide the shale into an oil play (VR 0.6–1.1% Ro) for the calculation of free oil or a gas play (VR: 1.1–3.0 %Ro) for the calculation of the GIIP. This subdivision is based on the average measured vitrinite reflectance (VR) or other forms of maturity data (Figure 2-3). Immature shale (VR > 0.6 %Ro) layers are not considered relevant for thermogenic hydrocarbons accumulations.

Geochemical characteristics

A target geochemical data collection was made to define the key geochemical parameters needed to define the shale capacity. The data collection aimed at addressing the organic carbon richness (TOC, wt%), the Kerogen type, the hydrocarbon potential (hydrogen index (HI), mg HC / g TOC), maturity (VR, %Ro) and sorption capacity. Both published and in-house data base was used. The results are presented for each analysed shale formation in Appendix A. For Denmark a specific study was made to characterise the Farsund Fm and its stratigraphical units based on a large in-house GEUS geochemical database (Schovsbo et al., 2020a).

Key geochemical parameters (organic carbon richness (TOC, wt%)and thermal maturity (VR, %Ro) have been included in the GIS attribute list.

Tectonostratigraphic and burial histories

The tectonostratigraphic and burial histories for each play were evaluated based on 3D basin modelling made as part of GARAH Delivery Report 2.4 for the Danish, German and northern part of the Dutch sector in the Central Graben. For the UK and Norwegian section of the North Sea the Basin modelling and techno-stratigraphical models made within the Millennium Atlas (2003) were evaluated. Additional burial models for the Carboniferous in UK and the Netherlands from Zijp et al. (2015) were evaluated.

Literature references for shale capacity description
A full list of references for the published data sources that related to the source rock properties and definition of the unconventional shale capacity parameters (CP) are presented in Appendix B.

2.2.3 Monte Carlo simulations

The GIIP and free oil volumes are obtained from stochastic distributions from Monte Carlo simulations considering the uncertainty ranges and probability density distribution of the input parameters. The assessment is made using the software "Crystal Ball® version 11.1" from Oracle® and with scripts developed in the EUOGA project (Ziip et al., 2017).

Oil initially in place (OIIP)

Free Oil

Free Oil is calculated as:

$$O_f = V \times \phi \times S_{oil} \qquad (1)$$

Where V is Volume (m³), ϕ is bulk porosity, S_{oil} is saturation of pore space in %.

Free Oil calculations were made on oil plays with the maturity range of 0.6–1.1 $\%R_o$.

Sorbed Oil
Is not calculated in the EUOGA method.

Gas initially in place (GIIP)

GIIP is calculated as:

$$GIIP = G_f + G_a \qquad (2)$$

Where $G_f + G_a$ is calculated as:

$$G_f = V \times \phi \times S_{gas} \times B_g \qquad (3)$$

Where G_f is free gas, V is volume (m^3), ϕ is bulk porosity, S_{gas} is saturation of pore space in % and B_g is expansion factor (gas formation volume factor) (Rm^3/Sm^3) [Reservoir vs Surface volume ratio].

$$G_a = V \times \rho \times G \qquad (4)$$

Where G_a is sorbed gas, V is volume (m^3), ρ is the rock density (g/cm^3) and G is the gas content (Langmuir Factor), which is calculated through:

$$G = \frac{P \times L_V}{P + L_P} \qquad (5)$$

Where G is the gas content (m^3/ton), P is the reservoir pressure (Pa), L_V is the *Langmuir Volume* (m^3/ton rock) and L_P is the *Langmuir Pressure* (Pa).

The Langmuir Factor and isotherms are developed to describe methane sorbed to the surface of kerogen, which is assumed to be in equilibrium with methane present in the gas phase.

GIIP calculations were made on gas plays with the maturity range of 1.1–3.0 %R_o.

Oil and gas saturation

The oil saturation distribution was evaluated from an average of European shales combined with data from North American shales. This gives an average saturation of 4.4% of the pore volume (Zijp et al., 2017). This estimate is used for the free oil calculation for plays when no saturation is given. For these shales the probability density distribution is assumed to be log normally distributed with a standard deviation of 0.083 and with a minimum value (location) of 0 (Figure 2-4; Zijp et al., 2017).

The gas saturations were estimated from the EUOGA data base of European shales if not provided (c.f. Zijp et al., 2017). The distribution is assumed to be triangular with likeliest value of 28%, the lowest value to be 3% and the highest value to be 67% of the pore-space (Figure 2-5).

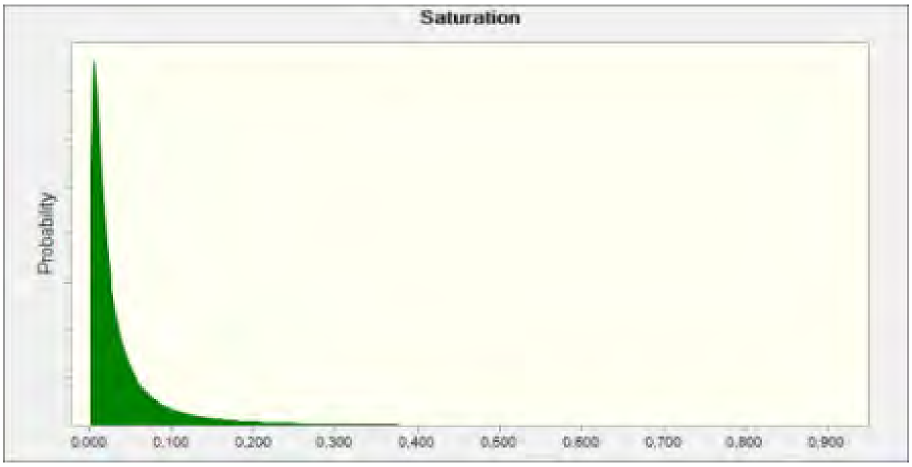

Figure 2-4 Probability density distribution of oil saturation. From Zijp et al. (2017).

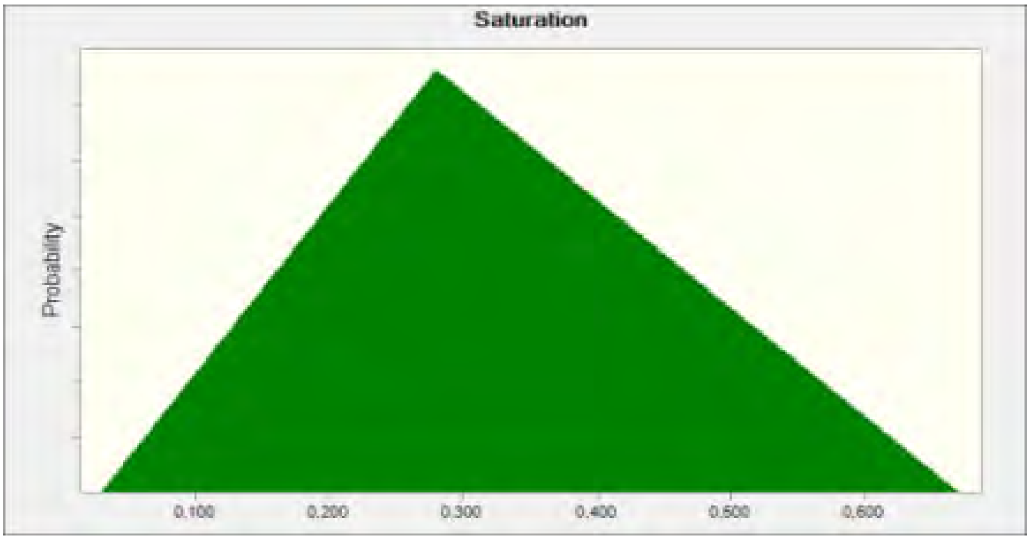

Figure 2-5 Probability density distribution of gas saturation. From Zijp et al. (2017).

Langmuir parameters

For very few shales measured *Langmuir Pressure* and Volume are reported for the kerogen and therefore, we use an average distribution reported by Zijp et al. (2017) based on measurements from both European and American shales (see Gasparik et al., 2012 for examples). According to this estimate the *Langmuir Volume* has a lognormal distribution with a mean of 69 Sft^3/ton rock and with a standard deviation of 34 at minimum value (location) of 5 (Figure 2-6). For the *Langmuir Pressure* the distribution is assumed to be lognormal with a mean of 1230 psi and with a standard deviation of 450 and a location of -300 (Figure 2-7).

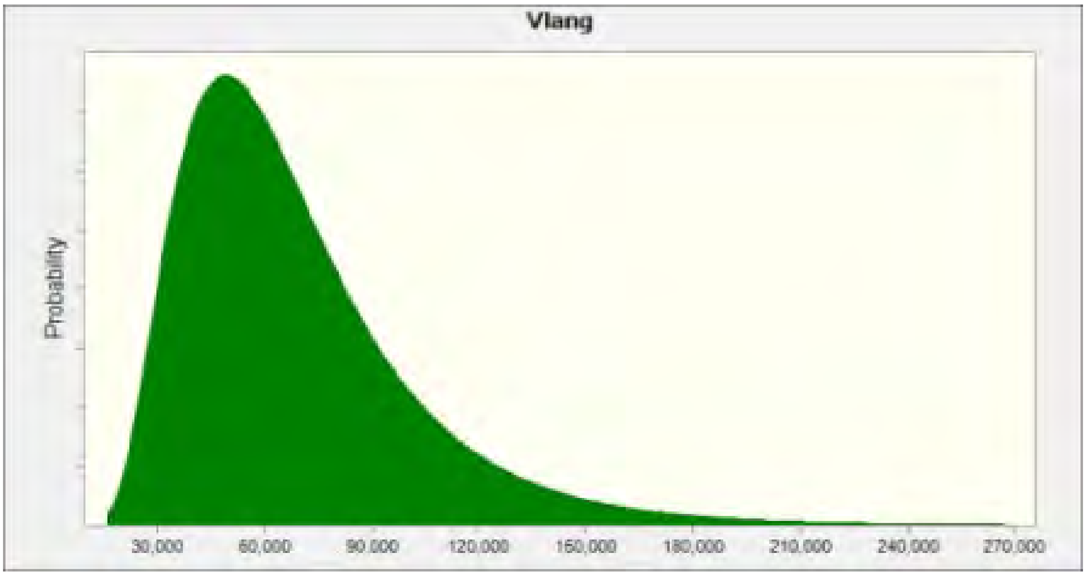

Figure 2-6 Probability density distribution of the *Langmuir Volume*. From Zijp et al. (2017).

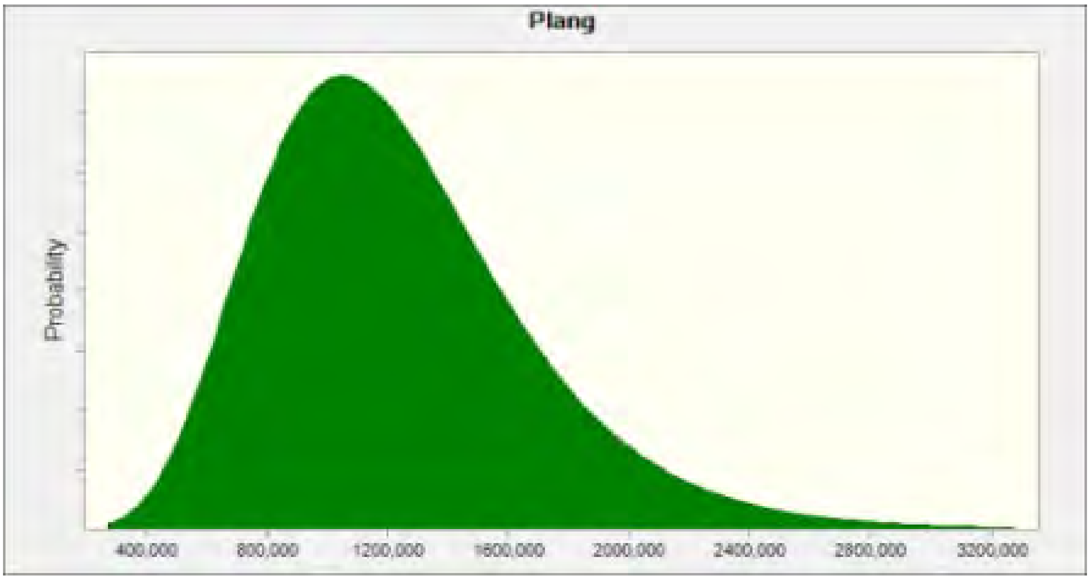

Figure 2-7 Probability density distribution of the *Langmuir Pressure*. From Zijp et al. (2017).

Gas expansion factor

The expansion factor of each formation is calculated based on the ideal gas equation together with the given temperature and pressure gradients of the formation as outlined by Zijp et al. (2017). For the three depths (minimum, median and maximum) the density of methane gas is calculated and compared to the density of gas at surface conditions. The website of NIST Chemistry Webbook (http://webbook.nist.gov/chemistry/) aids in determining the thermo physical properties of the fluid system, using 100% methane gas.

Temperature

Temperatures were estimated from provided gradients. If no gradient were provided, then a gradient of 30 ^{o}C/km has been assumed (cf. Schovsbo et al., 2020a). We also assume that the temperatures are distributed following a triangular distribution with the likeliest temperature reflecting the median depth of the formation and that the lowest and highest temperatures reflect the minimum and maximum depths of the formation.

Pore pressure

Pore pressures were estimated from provided pore pressure gradients. If no pressure data were available, then pressures were estimated to be hydrostatic in normal pressured basins i.e. 9.8 kPa/km. In overpressured parts of the North Sea the pressures were estimated according to the pore pressure gradients provided in Schovsbo et al. (2020a). We assume that the pressures are distributed following a triangular distribution with the likeliest pressure reflecting the median depth of the formation and that the lowest and highest pressures reflect the minimum and maximum depths of the formation.

Shale volume

The shale volume is calculated from the net shale thickness and the area of the formation that both provided as part of the screening and characterisation of the shale plays (c.f. Appendix A). The thickness distribution is assumed to be triangular if nothing else is reported. The likeliest thickness represents the median thickness and the lowest and highest represent the thinnest and thickest occurrence. The net shale thickness is the thickness excluding non-shale lithologies such as sandstone, siltstone, or carbonates.

Table 2-3 Uncertainty classification for areas with discrete mapping of the distribution. From Nelskamp (2017).

Type of data	***Class A***	***Shale distribution continuous***	***Shale distribution patchy***	***Class B***
3D seismic; >1 well/100 km2	1a	PDF=Normal M=Area SD=2.5%*Area	PDF=Normal M=Area SD=5%*Area	1b
3D seismic; <1 well/100 km2	2a	PDF=Normal M=Area SD=5%*Area	PDF=Normal M=Area SD=10%*Area	2b
2D seismic; >1 well/100 km2	3a	PDF=Normal M=Area SD=7.5%*Area	PDF=Normal M=Area SD=15%*Area	3b
2D seismic; <1 well/100 km2	4a	PDF=Normal M=Area SD=10%*Area	PDF=Normal M=Area SD=20%*Area	4b
Wells only	5a	PDF=Normal M=Area SD=25%*Area	PDF=Normal M=Area SD=50%*Area	5b

The area of the shale play is provided based on depth structure maps. The area for the free oil assessment is defined as the area between 1–5 km that has a maturity between 0.6–1.1 %R_o. The area for the GIIP assessment is defined as the area between 1–5 km that has a maturity between 1.1–3.0 %R_o.

For the uncertainty on the area estimate, we follow Zijp et al. (2017) if there is no other publicly available data. We thus assume that the true area is normal distributed with a standard deviation (SD) that reflect the data quality and well control. In plays with 3D seismic coverage the SD of the reported area is assumed to be 5–10% of the reported area and for plays mapped only with 2D seismic data then it is assumed that the SD is 10–15% of the reported area (c.f. Table 2-3).

3 ASSESSMENT OF HYDROCARBON PLAYS IN THE NORTH SEA BASIN

3.1 Conventional hydrocarbon plays in the North Sea Basin

A breakdown of the major conventional plays identified for each country is provided in GARAH Deliverable Report 2.2, and provided within the GARAH GIS with accompanying metada. Appendix D (Section 11) of this report shows harmonised maps for each of the play intervals evaluated in the GARAH area of interest. Note that the German offshore area is excluded from the GIS overview as Germany has not provided any information on plays.

While some efforts have been made to reconcile cross-border differences between plays in different sectors, a full re-interpretation is beyond the scope of the GARAH project. Each country evaluates their plays in different ways, and has different standards for defining what is conceptual or proven (see details of individual methodologies in Section 2.1.2). Despite the North Sea being a mature petroleum area, and the publication of a number of collaborative basin-scale geological studies and atlases (Evans et al., 2003; Doornenbal and Stevenson, 2010; Hopper et al., 2014) these cross-border differences remain, and are considered a concern in fully understanding the potential of the North Sea both in terms of conventional hydrocarbon extraction and for alternative use.

Below, we briefly highlight some examples of cross-border discrepancies in plays/stratigraphic intervals of interest – largely plays which are relatively underexplored, or where countries have idenfified new conceptual plays which stop abruptly at international borders.

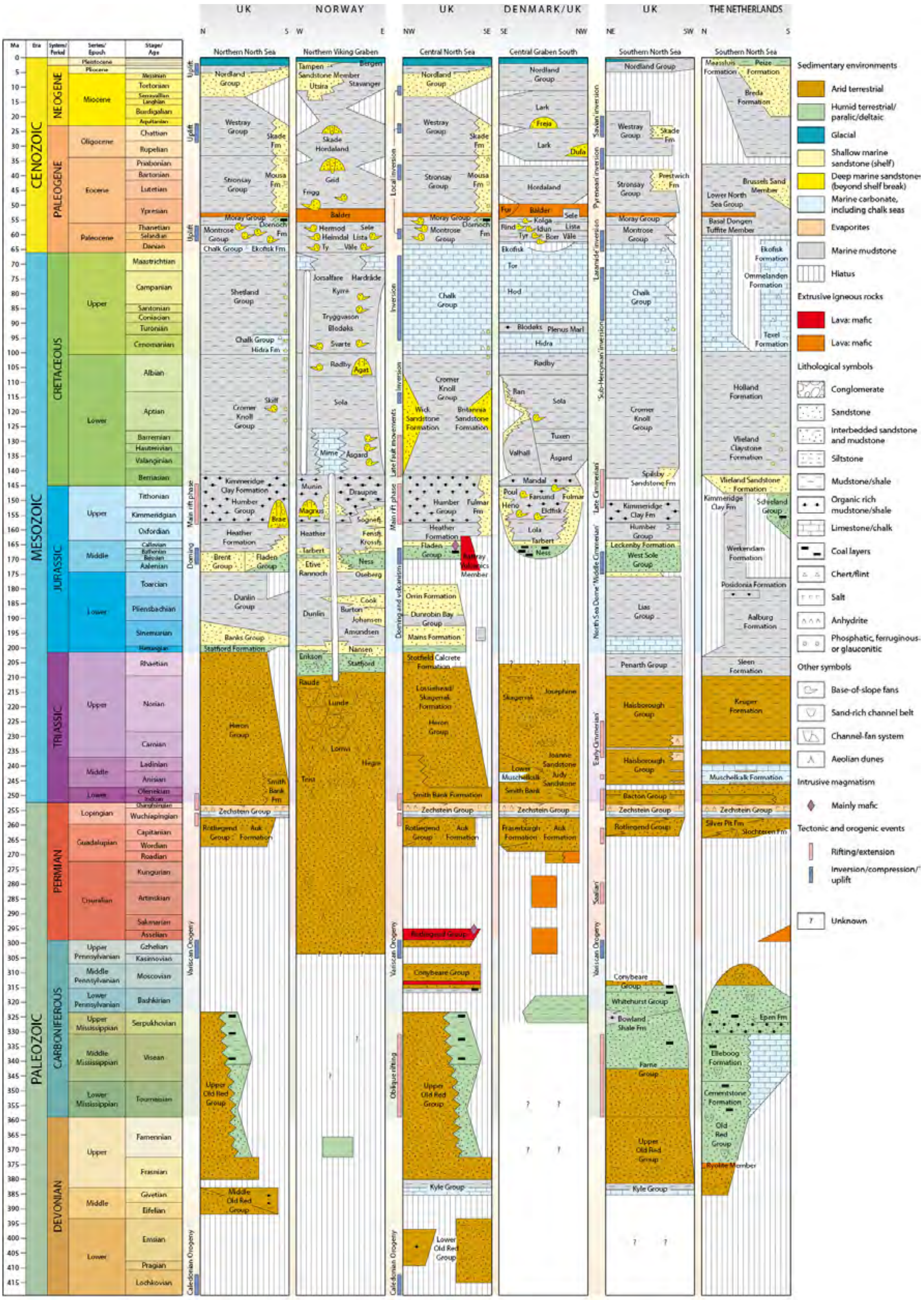

Figure 3-1 Generalised North Sea stratigraphic column. From Figure 11.18 of Hopper et al. (2014).

3.1.1 *Examples of Cross-Border issues*

3.1.1.1 Upper Cretaceous – UK, NL, NK, DK

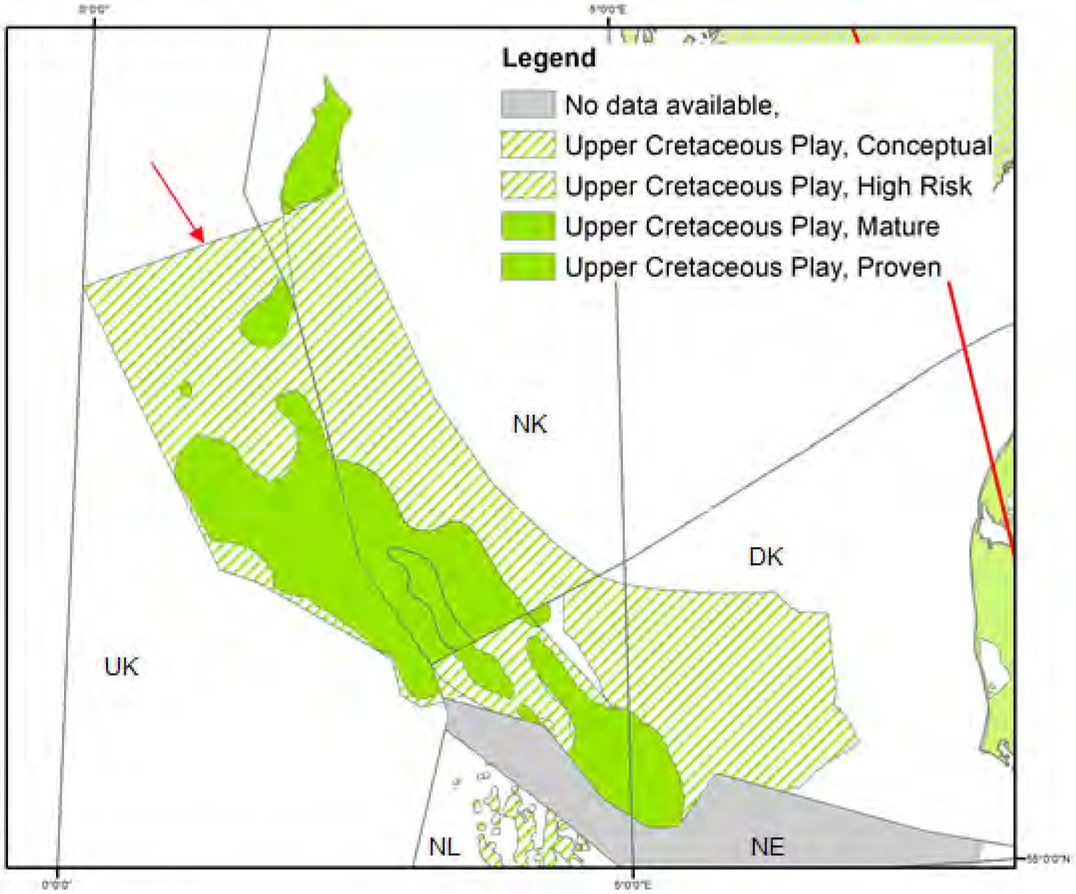

Figure 3-2 Detailed view of the Upper Cretaceous play areas in the five country cross border area.

Denmark

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 3-1). 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 fields trapped in a quasi dynamic state such as the Haldfan Field in the Salt Dome province (Albrechten et al., 2001). Deeper part of the Chalk Group (Hod-Hidra Fms) are also prospective where in areas where high overpressure has preserved porosity in the chalk.

In the Chalk play area high risk areas are found off-structure in the deeper parts of the basins where porosity preservation will be tied to the occurrence of pressure cells. Conceptual areas are located outside of the Central Graben and include parts that are envisioned to be within reach of long-distance migration of hydrocarbons generated within the Central Graben deeply buried Farsund Formation.

Norway

Similar type of chalk plays as found in Denmark also exists in the southern part of the Norwegian North Sea (Figure 3-2). Cross-border issues relates to the risk-classification as the northern extension of the high-risk play in Denmark borders a mature plays rank in Norway. This likely reflects geological condictions since the overpressure needed for porosity preservation in the Chalk is much higher in the southern part of Norwegian Central Graben than in the Danish part. However, difference in play perception cannot be ruled out.

The conceptual Chalk play located to west of the Central Graben that is recognised in Denmark was not recognised in the Play map inventory from the NPD. In this GARAH update, the extension of the conceptual play in Norway was redrawn, with the western border interpreted to relate maximum migration distance of oil from the Central Graben. The northern margin was aligned with the UK extent (see below).

UK

In the UK sector, the limits of the Conceptual or High Risk Upper Cretaceous play are based lagely on BGS mapping of the ‘Chalk Play’ which comprises potential Upper Cretaceous reservoirs, in particular: the Chalk Group; Ekofisk; Tor and Hod Formations. Of these, as in the Danish and Norwegian sectors, permeability in the Hod and Ekofisk Formations requires ares of high pressure to be viable (Surlyk et al., 2003) in the Central Graben of the North Sea. The outline of the conceptual area is based on very approximate limits of the Central Graben, as the distribution of Upper Cretaceous reservoir is considered extensive in this area (Lloyds Register for OGA, 2019). The SW-NE linear limit to the north extending into the Norwegian sector (red arrowed in Figure 3-2) reflects only the limit of mapping and the artificial internal boundary in UK mapping between the ‘central’ and ‘northern’ North Sea areas. Given the importance of the Chalk plays, particularly in the Danish and Norwegian sectors, a better understanding of cross-border potential of the Upper Chalk is consdiered to a priority in this area. In the UK sector, recent nearby discoveries in the Upper Jurassic (e.g. the Glengorm Discovery in 2019; OGA, 2021) are likely to lead to the acquistion of further subsurface data in the area.

Netherlands

The Upper Cretaceous play in the Netherlands can be a challenging play. Even though deposits of the Upper Cretaceous Chalk Group can be found in most of the offshore area, only five fields (oil in the Dutch Central Graben area and gas further south) were discovered. According to Doornenbal et al. (2019), this is mostly related to a lack of charge and not so much to a lack of reservoir. The main process defining reservoir properties in the Dutch Chalk Group is generally described as fracture porosity within the Upper Maastrichtian and Danian part. In adition, the known fields are located on top or in the vicinity of salt structures. The play area was therefore defined by the presence of the Chalk Group on mapped salt structures with a margin of 1.5 km. With the exception of the areas with known fields, these play areas were considered as conceptual.

3.1.1.2 Triassic – UK, NL

Netherlands

In the Netherlands the main reservoir units of the Triassic are located in the Lower Triassic Main Buntsandstein Formation in structural traps. Most fields contain gas sourced from the Carboniferous, but some stuctures in the southern offshore and onshore also contain oil or condensate, mostly due to fault juxtaposition with the Lower Jurassic Posidonia Shale Formation (Doornenbal et al., 2019). Most discoveries in Triassic reservoirs are located in the West Netherlands Basin and Broad Fourteens Basin in the southern part of the Dutch offshore as well as in the Terschelling Basin and southern part of the Dutch Central Graben. In addition to these proven plays cross border comparison with the mapped play areas in the UK indicate good exploration potential in Lower Triassic reservoirs further north, just south of the Mid North Sea High.

UK

As in the Netherlands, the main Triassic reservoir unit of interest in the UK sector of the southern North Sea is the Bunter Formation (equivalent to the Buntsandstein) – which is sourced from the Carboniferous. Play mapping reveals discrepancies at the UK/NL border; to the north, in the UK sector, the Bunter Sandstone Play is considered proven compared to conceptual in the NL sector (see green arrow in Figure 3-3). However, to the south, potential and mature Triassic plays in the NL sector clearly stop at the UK border (red arrow in Figure 3-3); largely a result of UK exploration in the area previously focusing on older well-established Permian plays. Recent work on the mid North Sea High (Brackenridge et al., 2018) highlight more extensive play potential towards the NL border in the Bunter play fairway. Cross border work in this region, particularly foscuing on the effect of the underlying salt, is likely to be useful in providing a more geologically controlled understanding of Triassic play potential into the NL sector.

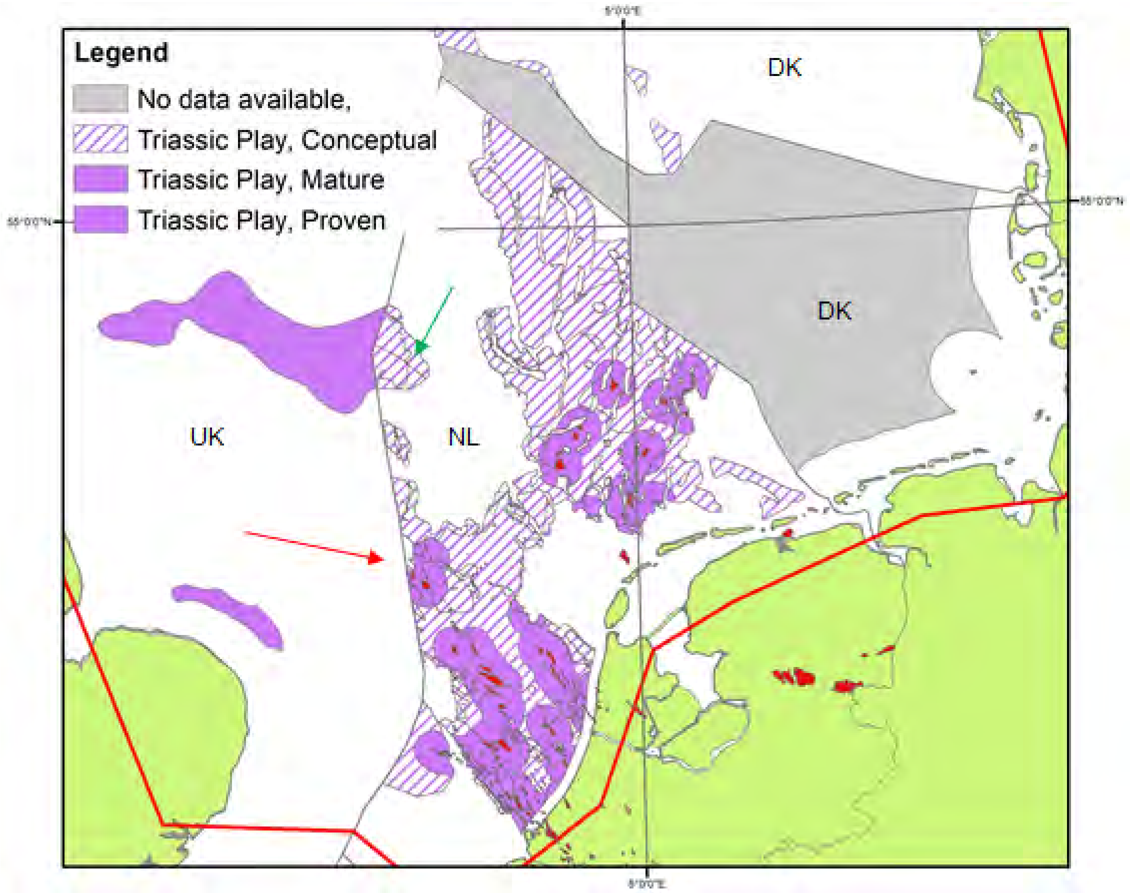

Figure 3-3 Detailed view of the Triassic Plays in the southern North Sea area

3.1.1.3 Carboniferous – UK, NL

Figure 3-4 shows a relatively good match for proven Carboniferous plays across the UK/NL border, but highlights a large conceptual play in the UK sector not idenfied in the NL sector (red arrow, Figure 3-4). The more extensive conceptual play is based on the identification by the OGA of the Carboniferous in parts of the UK Sector as underexplored, and subsequent data acquisition and work by Monaghan et al. (2015; 2017) to map the extent of the potential clastic Namurian Yoredale Formation reservoir, which is used to create the conceptual Carboniferous play in the UK sector in Figure 3-4. Namurian fluvial, fluvial/lacustrine and delatic facies were identified across the border in the GDE maps of Bachmann et al. (2010) with the potential to extend Triassic conceptual plays into the NL sector. More recently, play fairway analysis by Brackenridge et al., (2018, see their Figure 4.12) also shows good potential towards the south of the MNSH towards the border.

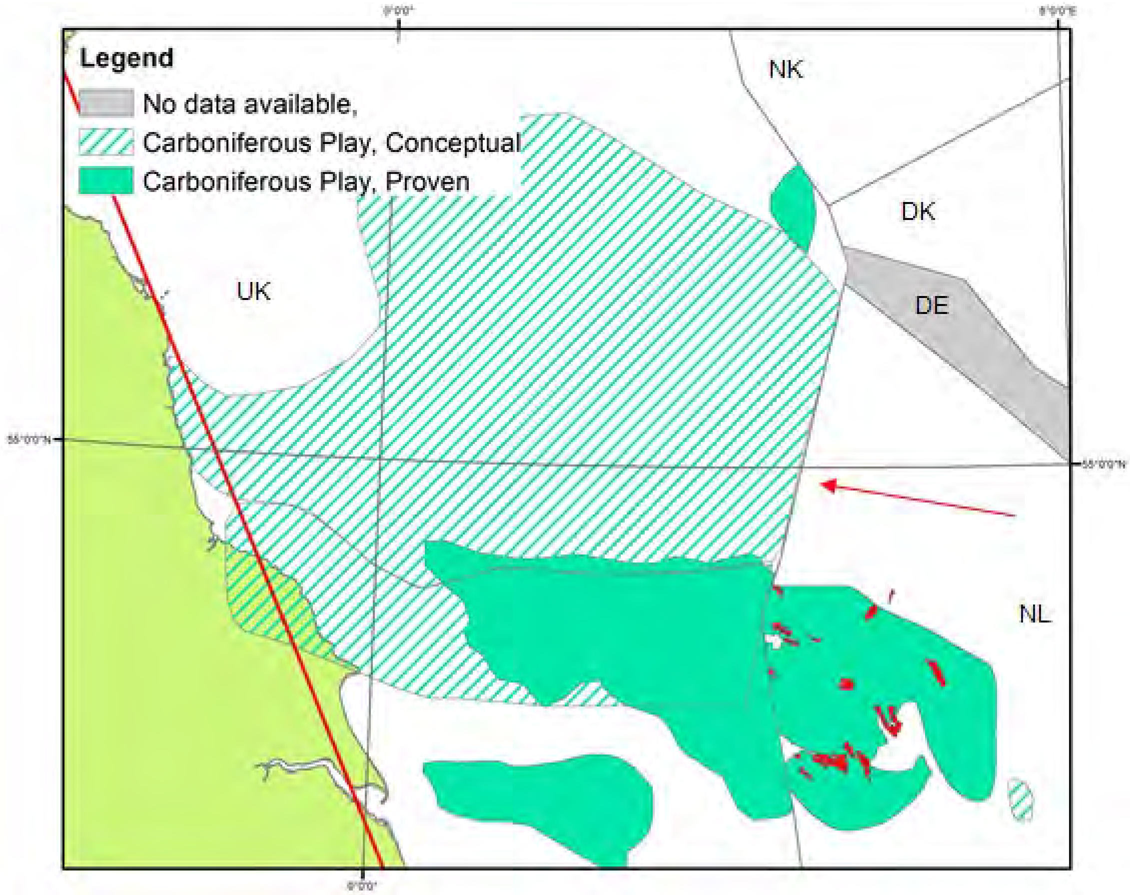

Figure 3-4 Detailed view of the Carboniferous play areas in the southern North Sea area

In the Netherlands the Namurian clastic reservoirs have not yet been studied in detail and therefore have not been assessed with respect to their hydrocarbon play potential in the context of this study. Based on the UK studies and previous studies in the Netherlands (e.g., ter Borgh et al., 2018), it is very probable that this conceptual play extends into the northern part of the Dutch offshore region.

3.2 Resource assessment of the conventional resource

Updates on resource assesments and potential resources are presented for each country below. Units for resources and reserves vary between countries, with the UK using imperial measures in barrels of oil equivalent (boe). In this report, the original data is reported and also converted into metric units, which are used by Denmark, Germany, the Netherlands and Norway. Conversion is based upon NPD factors, as outlined in Section 2.1.1.5 .

3.2.1 DE

The data availability and status of resources was addressed in GARAH Deliverable Report 2.2. For Germany, no national North Sea specific reserve and resource assessment was available.

3.2.2 DK

Data availability and resource status were previously updated in GARAH Deliverable Report 2.2. In Denmark the reserves and contingent resources are issued every second year by the Danish Energy agency. The assessment follows the PRMS system (classificationoilgas.pdf (ens.dk)) and provides data on: Production; Reserves (sum of 1P, 2P and 3P); Contingent resources (subdivided into Development pending (1C); Development unclarified or on hold (2C); Development not viable (3C); technological resource; and prospective resources based on the exploration prospects known at time of publication.

Table 3-1 Summary of conventional reserves and resources in Denmark pr. 1/1-2021 from the Danish Energy Agency (high prognosis). GEUS resources for *yet-to-find* is from Clausen et al., (2015 reported in Schovsbo et al., 2020b). Note volumes converted from Nm^3 to Sm^3 using NPD standards.

	Gas	**Oil**	**Oil eq**
	10^9 Sm^3	10^6 m^3	10^6 m^3
Produced	196	447	
Reserves	31	65	
Contingent resources	48	80	
Technological reource	1	15	
Exploration	6	22	
Yet-to-find:			
Discoveries (P50)			246
Prospects and leads (Category 2+3) unrisked (P50)			857
Prospects and leads (Category 2+3) risked (P50)			184
Possible additional resources unrisked (P50)			60
Possible additional resources risked (P50)			6

An evaluation of the prospective resources or *yet-to-find* resource in Denmark is presented by Clausen et al. (2015 reported in Schovsbo et al., 2020b). The *yet-to-find* resources include: Discoveries (Category 1) under evaluation; Prospects and leads (Category 2+3) un-risked; Prospects and leads (Category 2+3) risked; Possible additional resource's un-risked; and Possible additional resources risked. Within C category, 1,246x10^6 m^3 Oil equivalent is estimated and within category 2+3 857x10^6 m^3 (un-risked) oil equivalents or 190x10^6 m^3 risked oil equivalent are estimated (Table 3-1).

Following a play-based break-down of the resource most resource is present in the Upper Cretaceous – Paleogene Tor-Ekofisk Chalk play, followed by the Upper Jurassic and Mid Jurassic sandstone plays and the Palaeocene sand play in the

Siri Canyon (see GARAH Delivery Report 2.2 and Section 3.1). These plays are all proven in Denmark. High risk plays where no production has yet been established include sandstone reservoirs of Miocene sand, Upper Jurassic sandstone under HP/HT conditions and Jurassic and Lower Cretaceous turbidite sands (see Appendix D).

Conceptual play types include biogenic gas in Miocene or younger reservoirs, diatomite reservoirs and fractured basement in basement highs and plays that depend on long distance migration from the Central Graben or pre-Mid Jurassic source rock interval to charge.

3.2.3 NK

The data availability and status of the national resource assessments were updated in GARAH Deliverable Report 2.2.

Table 3-2 Summary of conventional reserves and resources in Norwegian North Sea pr. 31/12-2021. From [Resource accounts for the Norwegian shelf - Norwegianpetroleum.no (norskpetroleum.no)]

	Resource account as of 31.12.2020				
Total recoverable potential	***Oil***	***Gas***	**NGL**	***Condensate***	**Total**
Resource Class	10^6 Sm^3	10^9 Sm^3	10^6 tonn	10^6 Sm^3	10^6 Sm^3 o.e.
Produced	3882	2010	167	70	6280
Reserves	918	1016	47	0	2023
Contingent resources in fields	151	127	11	0	299
Contingent resources in discoveries	178	140	11	0	339
Undiscovered resources	375	240		50	665
Sum	**5504**	**3533**	**236**	**120**	**9605**

In Norway, a total of 24 plays have been defined by the NPD for the Norwegian part of the North Sea area (see GARAH Deliverables Report 2.2). Of these, four are unconfirmed. The most successful play in terms of resource volumes are the Cretaceous Chalk and Jurassic Sandstones reservoirs sources from the Upper Jurassic shales. The most promising in term of future development is the Upper Triassic to Lower Jurassic Sandstones plays sourced from Jurassic source rocks.

3.2.4 *NL*

The updated state of the natural resources and geothermal energy in the Netherlands is published in a yearly review report on https://www.nlog.nl/index.php/en/annual-reports. The report covers the exploration and production of hydrocarbons, rock salt and geothermal energy as well as the temporary storage of natural gas, oil and nitrogen) and permanent storage of brine and CO_2.

3.2.4.1 Reserves and Resources

The resources and reserves are updated yearly based on the reported estimates of remaning resources per accumulation and the expected annual production from the active operators in the Netherlands. Based on these reports the domestic resources and future production is estimated. The hydrocarbon resouces are subdivided into three classes, reserves (2P), contingent resources (2C – subcategory development pending) and prospective resources as described by the PRMS resource classification (Figure 2-1). The contingent resource subclasses 'unclarified', 'on hold' and 'development no viable' are not included in the recoverable resources. All estimates of resources in the Netherlands only refer to those in proven conventional plays and do not include conceptual or unconventional plays (see Table 3-3 and Table 3-4).

Table 3-3 Natural gas resources in the Netherlands in billion Nm³ as of 1 January 2021 (from https://www.nlog.nl/sites/default/files/2021-08/annual_report_2020_natural_resources_and_geothermal_energy_in_the_netherlands_30082021.pdf)

Area	Reserves	Contingent resources (development pending)	Total
Groningen	6.6	-	6.6
On land	28.4	32.9	61.3
At sea	57.4	12.9	70.3
Total	92.4	45.8	138.2

Table 3-4 Oil resources in the Netherlands in million Sm³ as of 1 January 2021 (from https://www.nlog.nl/sites/default/files/2021-08/annual_report_2020_natural_resources_and_geothermal_energy_in_the_netherlands_30082021.pdf)

Area	Reserves	Contingent resources (development pending)	Total
Land	9.2	5.0	14.1
Sea	2.5	13.0	15.5
Total	11.6	18.0	29.6

3.2.4.2 Assessment of prospective resources

The assessment of the prospective resources is only done for the natural gas resources as in agreement to current government policy. The prospectve resources are defined as “resources that have not yet been proven, but which are expected to be present and to be considered economically viable on the basis of technical data. Actual production can only be started if these expectations have been positively proven by an exploration well.” The reported prospective resources are based on a calculated exploration scenario based on the expected gas resources as supplied by the operators (see box in Chapter 1.4: https://www.nlog.nl/sites/default/files/2021-08/annual_report_2020_natural_resources_and_geothermal_energy_in_the_netherlands_30082021.pdf). Based on this exploration scenario the potential for known economically attractive prospective resouces was reported to be 64 billion m³ Geq (~62 billion Nm³ or 58 billion Sm³), see Figure 3-5.

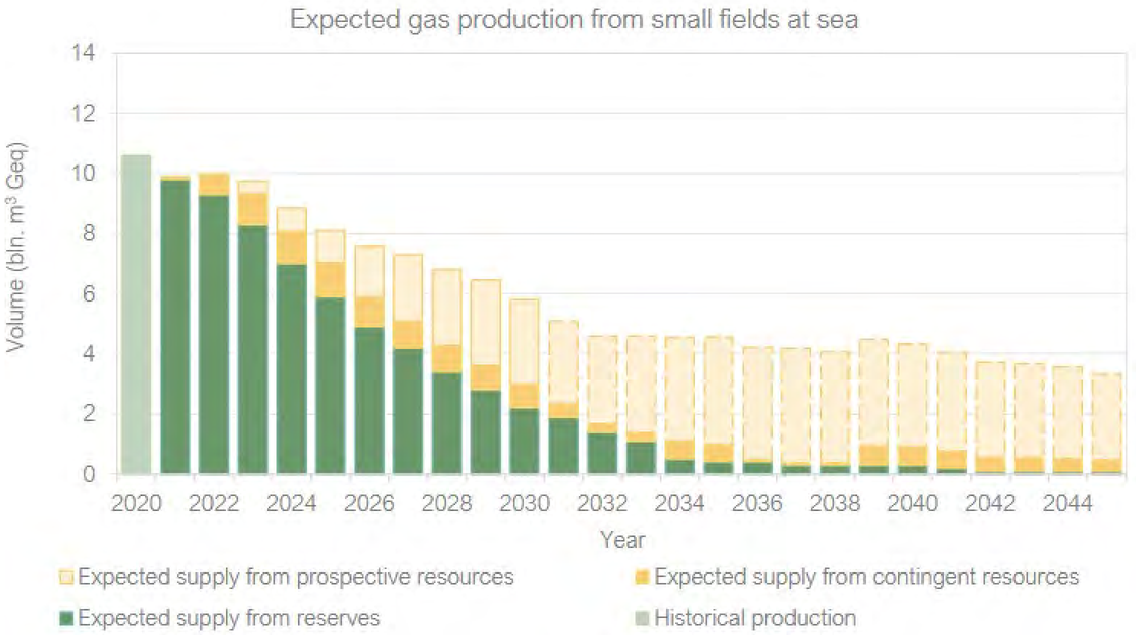

Figure 3-5 Actual production in 2020 and expected production from natural gas from the small fields

3.2.5 UK

3.2.5.1 UK Reserves and Resources

An update on UK offshore production and licensing for 2020 is provided in GARAH Deliverable Report 2.2. Since 1975, hydrocarbons produced from the UK North Sea are equivalent to 39 bilion boe, which is approximately 6.2 x 10^9 Sm^3 or 5.3 x 10^9 metric tonnes oil equivalent (OGA, 2018, 2020).

The OGA 2020 report on reserves and resources estimates total probable oil and gas reserves (2P) for the entire UK continental shelf (UKCS) reserves at 5.2 x 10^9 boe at end 2019, as shown in Table 3-5. This is slightly less than the 5.5 x 10^9 boe reported at end 2018 (OGA, 2018), due to the production of around 600 million boe in 2019 and no replacement to the reserves base. Contingent resources at 2C confidence level are reported as: 2.1 x 10^9 boe for producing fields; 1.7 x 10^9 boe for proposed new developments, and 3.5 x 10^9 boe for marginal discoveries.

Table 3-6 shows the same figures converted into metric tonnes and million Sm^3 using the Norwegian Petroleum Directorate conversion standards, as outlined in Section 2.1.1. Converting to metric units using the NPD conversions (NPD, 2021) results in the 2019 5.5 billion boe reserves being approximately equivalent to 709 x 10^6 tonnes oil equivalent, or 827 x 10^6 Sm^3.

Table 3-5 Total UK offshore oil and gas reserves and resources in billion (10^9) boe at end 2019 and 2018. Modified from Table 1 of OGA (2020), Table 1 of OGA (2018), Appendix D3 and D4 of OGA (2020) and Appendix D3 and D4 of OGA (2018).

Reserves (Oil and Gas)	**2019 (2P, bboe)**	**2018 (2P, bboe)**
Total	5.2	5.5
Contingent Resources	**2019 (2C)**	**2018 (2C)**
Producing fields	2.1	2.3
Proposed new developments	1.7	1.9
Marginal discoveries	3.5	3.3

Table 3-6 Total UK offshore oil and gas reserves and resources coverted into metric tonnes and cubic metres for this study. *Conversions based on those published by the Norwegian Petroleum Directorate (NPD, 2021).

Reserves (Oil and Gas)	***2019 (2P, x 10^6 metric tonnes)****	***2019 (2P, x 10^6 Sm^3)****	***2018 (2P, x 10^6 metric tonnes)****	***2018 (2P, x 10^6 Sm^3)****
Total	*709*	*827*	*750*	*874*
Contingent Resources	***2019 (2C)****	***2019 (2C)****	***2018 (2C)****	***2018 (2C*)***
Producing fields	*286*	*334*	*314*	*366*
Proposed new developments	*232*	*270*	*259*	*302*
Marginal discoveries	*477*	*556*	*450*	*525*

Reserves and contingent resources were also broken down by type into oil (Table 3-7) and gas (Table 3-8) for the whole of the UKCS. Note that conversion into Sm^3 was done for this study based on NPD standards (NPD, 2021).

Table 3-7 UK offshore oil reserves and resources for entire UKCS in bboe and metric tonnes for end 2018 and end 2019. Values in bboe and million metric tonnes are compiled from and values taken from Table 3 of OGA (2020), Table D3 of OGA (2020), Table 3 of OGA (2018), and Table D3 of OGA (2018). Conversion from boe to metric tonnes is from the OGA reports (2018, 2020). *values in million Sm^3 were calculated for this study based on conversion factors from the Norwegian Petroleum Directorate using the published OGA figures (NPD, 2021).

Reserves (Oil)	**2019 (2P, bboe)**	**2019 (2P, x 10^6 metric tonnes)**	***2019 (2P, x 10^6 Sm^3)****	**2018 (2P, bboe)**	**2018 (2P, x 10^6 metric tonnes)**	***2018 (2P, x 10^6 Sm^3)****
Reserves	3.6	481	*560*	3.8	507	*590*
Contingent Resources	**2019 (2C)**	**2019 (2P, x 10^6 *metric* tonnes)**	***2019 (2P, x 10^6 Sm^3)****	**2018 (2C)**	**2018 (2P, x 10^6 metric tonnes)**	***2018 (2P, x 10^6 Sm^3)****
Producing fields	1.5	199	*231*	1.5	200	*233*
Proposed new developments	1.5	197	*229*	1.5	200	*233*
Marginal discoveries	2.1	284	*331*	2.1	280	*326*
Total Contingent Resources	5.1	680	*792*	5.1	680	*792*

Table 3-8 UK offshore gas reserves and resources for entire UKCS in billion barrel of oil equivalent and million/billion cubic metres for end 2018 and end 2019. Compiled from Table 4 of OGA (2020), Table D4 of OGA (2020), Table 4 of OGA (2018), and Table D4 of OGA (2018). Conversion from boe to billion m³ is from the OGA reports (2018, 2020).

Reserves (Gas)	**2019 (2P, bboe)**	**2019 (2P, x 10^9 m³)**	**2019 (2P, x 10^6 m³)**	**2018 (2P, bboe)**	**2018 (2P, x 10^9 m³)**	**2018 (2P, x 10^6 m³)**
	1.6	260	260 000	1.7	279	279 000
Contingent Resources	**2019 (2C)**			**2018 (2C)**		
Producing fields	0.7	108	108 000	0.8	131	131 000
Proposed new developments	0.3	43	43 000	0.3	49	49 000
Marginal discoveries	1.4	223	223 000	1.2	197	197 000
Total Contingent Resources	2.3	274	274 000	2.3	378	378 000

Reserves and resources were also examined by area, as shown in Figure 3-6 for oil, and for gas in Figure 3-7. For the GARAH project focusing on the North Sea, of most interest are the proportions from the northern (NNS), central (CNS) and southern (SNS) North Sea. However, the numbers for these areas were not released publicly except in graph form.

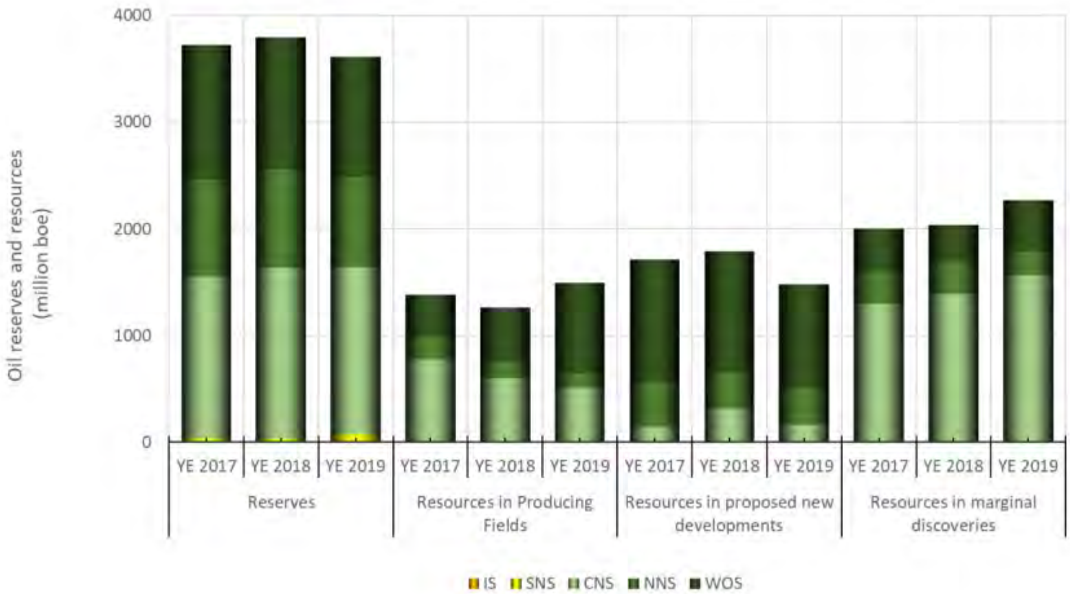

Figure 3-6 UK offshore oil reserves and resources by area at 2P/2C. Reproduced from Figure 9 of OGA (2020, p.13). SNS figures in yellow, CNS in light green, and NNS in darker green.

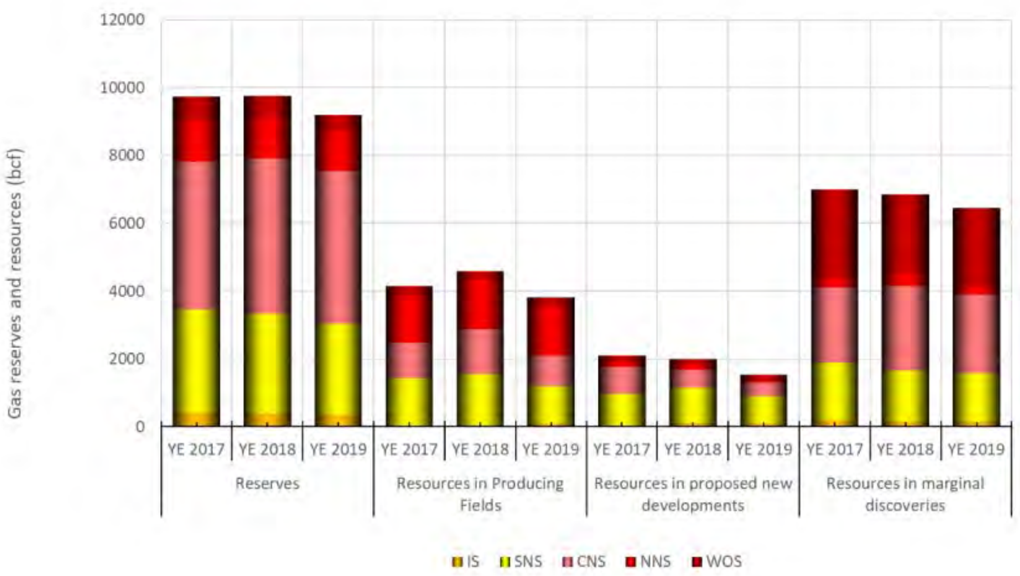

Figure 3-7 UK offshore gas reserves and resources by area at 2P/2C. Reproduced from Figure 10 of OGA (2020, p.13). SNS figures in yellow, CNS in pink, and NNS in red.

For both gas and oil, the largest reserves for the years 2017, 2018 and 2019 are contained within the central North Sea (CNS). For oil, resources in producing fields are also largest within the CNS, but for gas, the southern north Sea (SNS) and northern North Sea (NNS) play a more significant role. For oil resources in new developments, the NNS and CNS are most significant; for gas resources are mostly within the SNS. Resources in marginal discoveries are highest in the CNS for both gas and oil.

3.2.5.2 Prospective Resources

An update on UK production and licensing for 2020 is provided in GARAH Deliverable Report 2.2.

The 2020 OGA report on UK offshore reserves and resources estimates a total of between 10 and 20 billion barrels of oil equivalent remaining across the UK continental shelf (UKCS) including discovered and undiscovered resources. In metric units this is equivalent to around 1.6 x 10^9 Sm^3 or 1.4 x 10^9 metric tonnes, when converted using NPD (2021) standards.

The mean total prospective resources for the whole UKCS and associated with mapped leads and prospects is calculated at 4.1 x 10^9 boe, which remains unchanged from the previous OGA (2018) report. Details for lead and prospect - level basins in the North Sea GARAH area of interest are shown in Table 3-9. The Central North Sea (CNS) is estimated to contain the highest amount of prospective resources, followed by the Northern (NNS) and Southern (SNS) areas. Prospective resources in the SNS are expected to be dominated by gas (95%). A metric version of the data in Sm^3 is provided in Table 3-10 and was produced using NPD conversion factors (NPD, 2021).

Table 3-9 UK Lead and Prospect-level resources by basin in North Sea(with cut-offs applied). Modified from Table 5.2A of OGA (2020).

	Oil equivalent (x 10^9 boe)							
Basin	**P99**	**P90**	**P50**	**Mean**	**P10**	**P1**	**%Gas**	**Features**
NNS	0.2	0.3	0.5	0.6	1.0	2.1	20	97
CNS	0.9	1.2	1.7	1.9	2.7	5.4	27	281
SNS	0.1	0.2	0.4	0.5	0.9	2.1	95	58

Table 3-10 Lead and Prospect-level resources by basin in North Sea(with cut-offs applied). Original values from Modified from Table 5.2A of OGA (2020)*values in million Sm^3 were calculated for this study based on conversion factors from the Norwegian Petroleum Directorate using the published OGA figures (NPD, 2021).

	Oil equivalent (x 10^6 *Sm^3*)*							
Basin	**P99**	**P90**	**P50**	**Mean**	**P10**	**P1**	**%Gas**	**Features**
NNS	*32*	*48*	*79*	*95*	*159*	*334*	20	97
CNS	*143*	*191*	*270*	*302*	*429*	*859*	27	281
SNS	*16*	*32*	*64*	*79*	*143*	*334*	95	58

A potential prospective resource of 11.2 billion boe is estimated in plays where leads and prospects are not yet mapped, with details for the North Sea shown in Table 3-11. The most prospective area is also the CNS with a mean prospective resource of 1.5 billion boe. A metric version of the data in Sm^3 is provided in Table 3-12 and was produced using NPD conversion factors (NPD, 2021).

Table 3-11 UK play-level prospective resources by basin in North Sea (with cut-offs applied). Modified from Table 5.3 of OGA (2020).

	Oil equivalent (x 10^9 boe)					
Basin	**P99**	**P90**	**P50**	**Mean**	**P10**	**P1**
NNS	0.2	0.4	0.8	0.9	1.7	2.7
CNS	0.6	0.9	1.4	1.5	2.1	2.8
MNSH	0.0	0.1	0.5	0.5	1.1	1.6
SNS	0.2	0.4	0.8	0.8	1.2	1.6

Table 3-12 Play-level prospective resources by basin in North Sea (with cut-offs applied). Original values from Table 5.3 of OGA (2020).)*values in million Sm^3 were calculated for this study based on conversion factors from the Norwegian Petroleum Directorate using the published OGA figures (NPD, 2021).

	Oil equivalent (x 10^6 *Sm^3*)*					
Basin	**P99**	**P90**	**P50**	**Mean**	**P10**	**P1**
NNS	*32*	*64*	*127*	*143*	*270*	*429*
CNS	*95*	*143*	*223*	*238*	*334*	*445*
MNSH	*0*	*16*	*79*	*79*	*175*	*254*
SNS	*32*	*64*	*127*	*127*	*191*	*254*

3.3 Unconventional hydrocarbon plays in the North Sea Basin

3.3.1 Characterization of plays

In GARAH Deliverable Report 2.2 the North Sea Basin was screened for potential unconventional hydrocarbon source rocks following commonly accepted screening parameters (e.g., Greenhalgh, 2016) based primarily on the TOC and thickness. The outcome is presented in Table 3-1 and Figure 3-1. No biogenic unconventional shale plays were reported, and thus only thermogenic oil and gas play are under discussion here.

Table 3-13 Thermogenic unconventional plays in the North Sea Basin. Note that the Alum Shale (CP 3001) is not assessed as the occurrence is hypothetical in the North Sea Area. From the GARAH Deliverable Report 2.2

CP	Basin	Area	Shale	Age	Maturity	Area analysis	Status	Class
3001	North Sea	Dk	Alum Shale	Cambrian - Ordovi.	Gas	Not assessed	Hypotheti-cal	3
3002	Central Graben	Dk	Bo Member, Farsund Formation	L. Creta-ceous	Gas	From 3D GeoERA model	Active Petroleum system	1
3003	Central Graben	Dk	Farsund Fm (excl Bo member)	U Jurassic	Oil	From 3D GeoERA model	Active Petroleum system	1
3004	Central Graben	DK	Posidonia Shale eq.	L Jurassic	Gas	Not assessed	Hypothetic al	3
3005	Central Graben	NK	Mandal Formation	U Jurassic - L Creta-ceous	Oil/Gas	From Millennium Atlas polygons	Active Petroleum system	1
3006	Central Graben	DE	Sleen Fm	Rhaet-Trias	Oil	Volume from 3D model	hypothetica l	2
3007	Central Graben	DE	Posidonia Shale	L Jurassic	Oil	From 3D GeoERA model	Active Petroleum system	1
3007	Mittelpl ate	DE	Posidonia Shale	L Jurassic	Oil	From 3D GeoERA model	Active Petroleum system	1
3008	Central Graben	DE	Hot Shale - Bo Member eq.	L Creta-ceous	Oil	From 3D GeoERA model	Active Petroleum system	1

3009	Central Graben	NL	Geverik Member	Missis-sippian	Oil/Gas	From 3D GeoERA model	Active Petroleum system	1
3010	Central Graben	NL	Posidonia Shale	L Jurassic	Oil	From 3D GeoERA model	Active Petroleum system	1
3011	North Sea	UK	Bowland-Hodder - Geverik Eqv.	M Carboni-ferous	Gas	From BGS polygons	Active Petroleum system	1
3012	North Sea	UK	Kimmeridge clay equivalent	U Jurassic	Oil/Gas	From Millennium Atlas polygons	Active Petroleum system	1
3013	North Sea	UK	Posidonia Shale eq.	L Jurassic	Oil/Gas	From Millennium Atlas polygons	Active Petroleum system	1

Following the EUOGA approach, a series of screening parameters for capacity and characterisation (henceforth abbreviated CP-parameters) were collected for each shale. The CP parameters include 22 parameters ranging from thickness, organic type, richness, maturity, absorptions parameters and mineralogy and are presented in full in Appendix A. In addition to providing the needed information for the assessment the CP also provides a unique ID for each formation used a quick reference; CP 3001-3013 (Table 3-13, Figure 3-8).

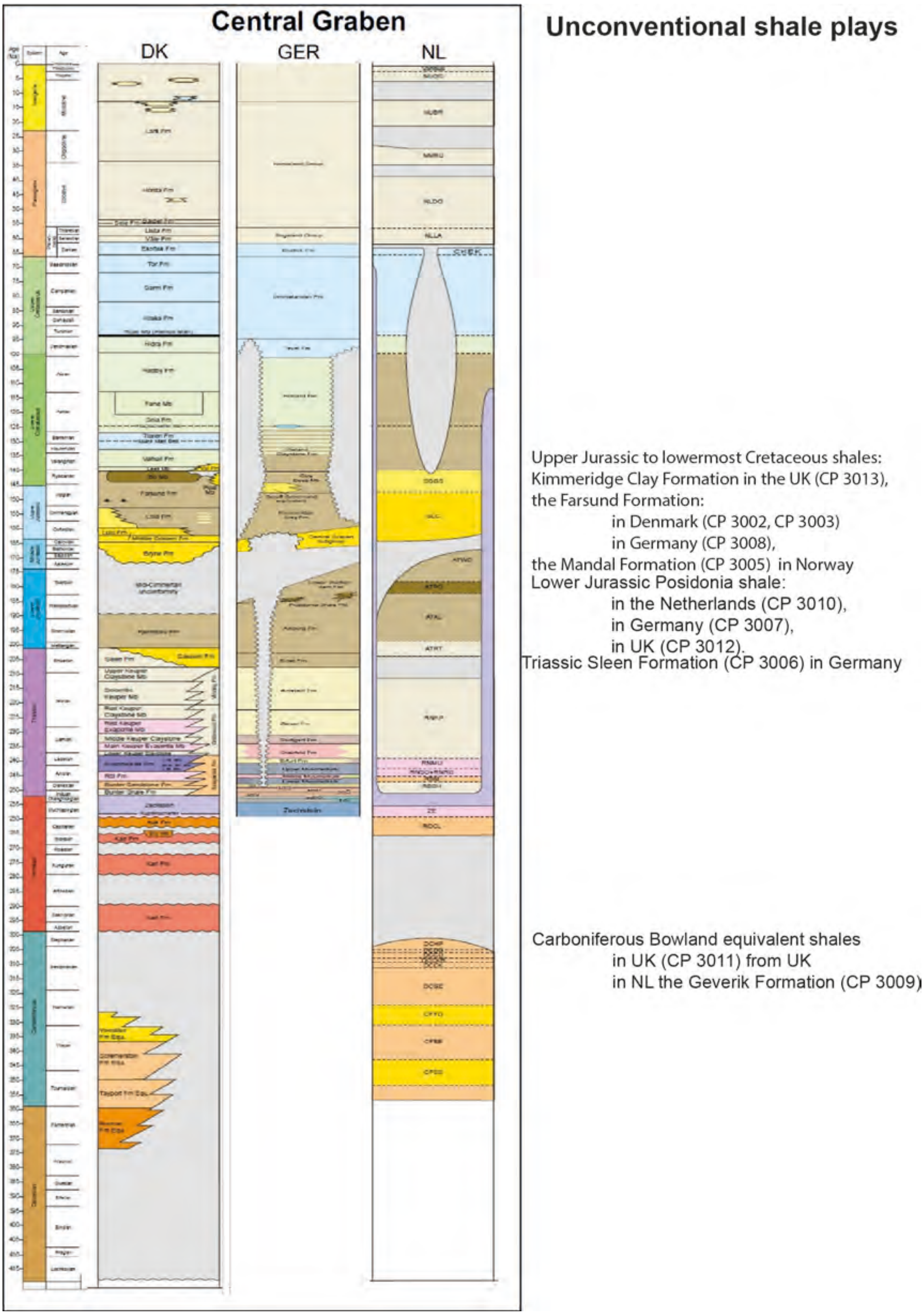

Figure 3-8 Stratigraphical overview of the North Sea Unconventional plays. The stratigraphical scheme for the Dk-D-NL Central Graben is from 3DGEO-EU Deliverable Report 3.3

The shales include the known source rock levels in the North Sea notably the Upper Jurassic to lowermost Cretaceous shales: Kimmeridge Clay Formation in the UK (CP 3013), the Farsund Formation in Denmark (CP 3002, CP 3003) and

Germany (CP 3008), and the Mandal Formation (CP 3005) and Heather Formation (CP 3014) in Norway (CP 3005). Also, the Lower Jurassic Posidonia shale in the Netherlands (CP 3010), Germany (CP 3007), Denmark (The Fjerritslev Formation CP 3004) and UK (CP 3012). Apart from these Jurassic shales the Triassic Sleen Formation (CP 3006) in Germany, the marine Carboniferous Bowland equivalent shales (CP 3011) from UK and the Geverik Formation (CP 3009) from the Netherland and the Cambrian-Ordovician Alum Shale (CP 3001) from Denmark were identified. The latter shale and the Lower Jurassic Fjerritslev Formation in Denmark are poorly defined offshore and hypostatical and is not associated with a proven petroleum system or poorly mapped or both and therefore not all is considered relevant for assessing (Class 1-2 in Table 3-13).

The shales are on most parameters quite alike; they are all marine, organic rich and dominated by Type II kerogen. The main deviation in parameters is seen for the reported thicknesses and structural setting. Apart from the Upper Jurassic syn-rift shales these are less than 100 m in thickness whereas the thickness may exceed 1 km for the Upper Jurassic shales in UK and NK sectors of the North Sea.

3.3.2 ***Assessment of yet-to-find resources***

The assessments of the analysed unconventional plays are described per country below. The probabilistic assessments of free oil and GIIP resources are based on 10,000 trials using Monto Carlo simulations as described in Section 2.2.3. Graphics of the Monto Carlo simulation results are presented in Appendix C.

3.3.3 DE

The oil and gas mature play in the Triassic Sleen Formation (Figure 3-9) that is within 1–5 km depth has an area of 500 km^2 and 250 km^2 respectively (Table 3-14). In the Central Graben the Posidonia shale is developed both as a gas and as an oil play with areas of 197 km^2 and 470 km^2 respectively. In the Mittelplate area (situated in the Wadden Sea within the GARAH area, see Figure 3-9) the Posidonia shale is only developed as oil play with an area of about 900 km^2. Like in the Danish part of the Central Graben an oil play is present in the Bo Member of the Farsund Formation. This play has an area of approximately 650 km^2 (Table 3-14).

The assessed resources are tabulated in Table 3-15. In the Triassic Sleen Formation oil play a free oil resource of $26x10^6$ m^3 (P50) and a GIIP resource of $66x10^9$ m^3 (P50) is estimated. In the Bo Member oil play a free oil resource of $29x10^6$ m^3 (P50) is estimated whereas the shale is not considered to have a gas play. The Lower Jurassic Posidonia shale has been assessed both in the Central Graben and in the Mittelplate area. In the Mittelplate area the Posidonia shale is oil mature, and the oil play has an estimated free oil resource of $86x10^6$ m^3 (P50). In the Central Graben the Posidonia shale is considered to have both an oil and gas play with an estimated $23x10^6$ m^3 (P50) free oil and an estimated GIIP of $44x10^9$ m^3 (P50) respectively.

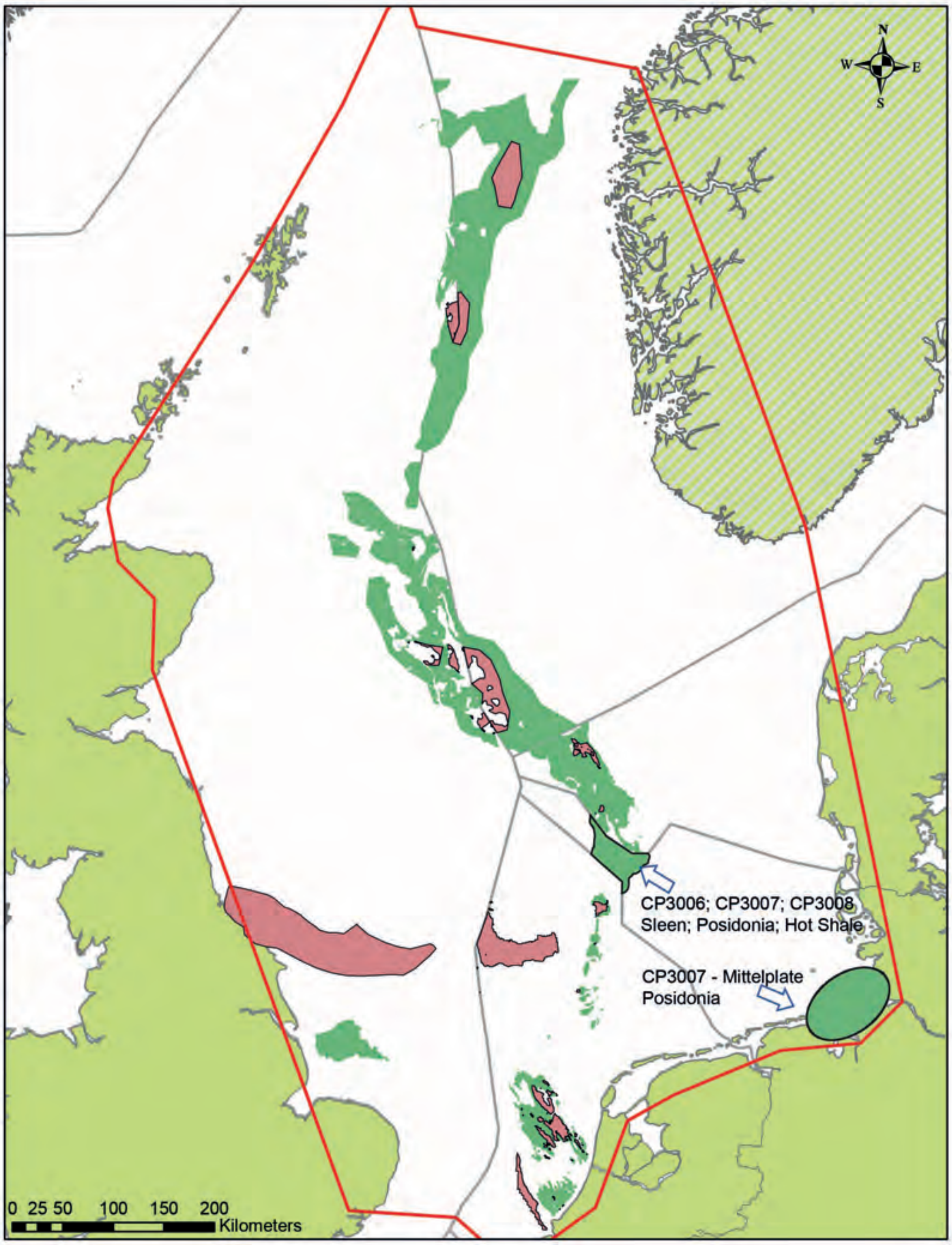

Figure 3-9 Oil and gas plays in the German part of the North Sea and in the Wadden Sea.

Table 3-14 Volume input data for the oil and gas plays in the German part of the North Sea Basin and in the Wadden Sea. AU: Assessment unit.

Sleen Formation (CP 3006)						
Present day 1 – 5 km	Mean	Std	Min	Likeliest	Max	Unit
Oil mature area	500	250	375		625	km^2
Gas mature area	250	125	188		313	km^2
Thickness (net)			5	20	30	m
Posidonia Shale (CP 3007)						
Present day 1 – 5 km						
For Mittelplate AU:	Mean	Std	Min	Likeliest	Max	Unit
Oil mature area	900	135	833		968	km^2
Gas mature area	–					km^2
Thickness (net)			20	35	50	m
For Central Graben AU:	Mean	Std	Min	Likeliest	Max	Unit
Oil mature area			29	250	470	km^2
Gas mature area			6	102	197	km^2
Thickness (net)			20	35	50	m
Hot Shale (CP 3008)						
Present day 1 – 5 km	Mean	Std	Min	Likeliest	Max	Unit
Oil mature area	650	325	488		813	km^2
Gas mature area	–					km^2
Thickness (net)			5	15	30	m

Table 3-15 Assessment results for the oil and gas plays in the German part of the North Sea Basin and in the Wadden Sea.

		Sorbed Gas			Free Gas			GIIP			Free Oil		
CP	**Shale**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
		10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^6m^3	10^6m^3	10^6m^3
3006	Sleen Fm	6	14	31	23	49	97	36	66	115	5	26	137
3007	Posidonia Shale Central Graben	4	11	24	11	31	71	21	44	86	4	23	119
3007	Posidonia Shale Mittelplate		--			--			--		17	86	433
3008	Hot Shale - Bo Mbr eqv.		--			--			--		6	29	163

3.3.4 DK

In Denmark the Farsund Formation has been divided into an oil play represented by the Bo Member of the upper Farsund Formation and a gas/oil play represented by the deeper parts of the Farsund Formation (Figure 3-8, Figure 3-10 Oil and gas plays in the Danish part of the North Sea.). For calculating the prolific volume of the Bo Member, we use the depth and maturity of the topmost Farsund Formation and for the deeper gas/oil play we use the depth of the mid to base Farsund Formation. The thickness of the deep gas mature Farsund Formation is assumed to range between 20–100 m (Table 3-13).

In the Bo Member the oil mature play has a size of 3,772 km^2, whereas the gas mature play is negligible (18 km^2) (Table 3-13). In the deeper regions of the Farsund Formation the area of the oil mature play decreases slightly and the gas mature play area increases slightly (2,564 km^2 and 280 km^2, respectively)

The assessed resources are tabulated in Table 3-3. In the Bo Member a free oil resource of $338x10^6$ m^3 (P50) and a negligible gas resource is estimated. In the deeper Farsund Formation a free oil resource of $697x10^6$ m^3 (P50) and a GIIP resource of $259x10^9$ m^3 (P50) is estimated.

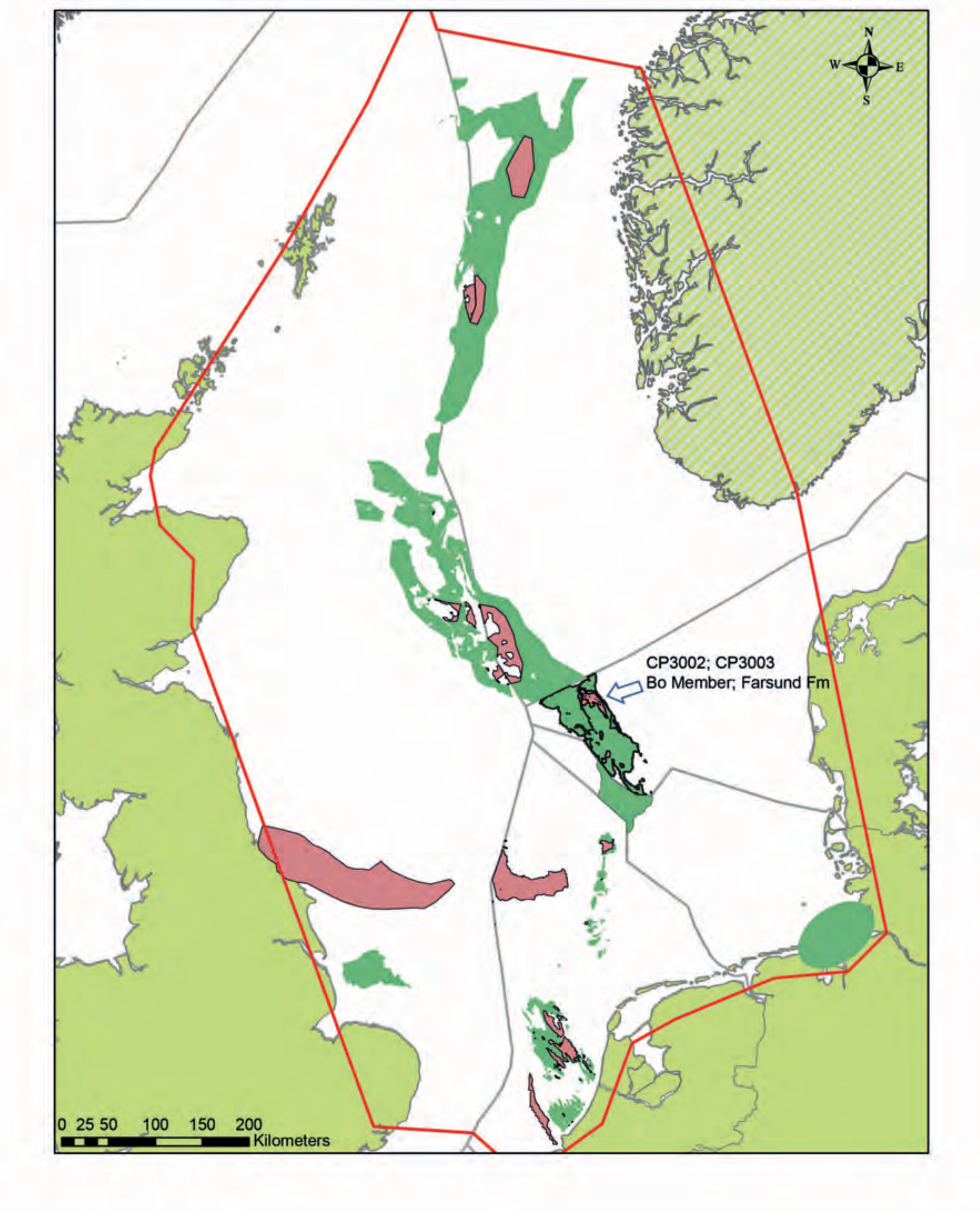

Figure 3-10 Oil and gas plays in the Danish part of the North Sea.

Table 3-16 Volume input data for the oil and gas plays in the Danish part of the Central Graben.

Bo Member (CP 3002)						
Present day 1 – 5 km						
	Mean	Std	Min	Likeliest	Max	Unit
Area oil mature	3772	189	3583		3961	km^2
Area gas mature	18	1	17		19	km^2
Thickness			15	35	50	m

Table 3-17 Assessment results for the oil and gas plays in the Danish part of the Central Graben.

		Sorbed Gas			Free Gas			GIIP			Free Oil		
CP	**Shale**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
		10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^6m^3	10^6m^3	10^6m^3
3002	Bo Mbr, Farsund Fm	1	2	4	0	1	2	2	3	5	67	338	1761
3003	Farsund Fm deep	33	67	133	72	181	366	139	259	453	138	697	3506

3.3.5 NK

In Norway, the Upper Jurassic Mandal Formation occurs in the Central Graben and in the Viking Graben within the North Sea Basin (Figure 3-11). The oil play is 17,219 km^2 and the gas play is estimated to be 3,007 km^2 (Table 3-18). The estimated net shale thickness of the prospective unit ranges between 20–1,153 m, similar to the Kimmeridge Clay Formation in UK. For resource assessments, we applied - similarly to the UK assessment - both the reported net thickness variation and a model thickness variation that range up to 100 m in thickness (Table 3-18).

The assessed resources are tabulated in Table 3-19. In the Mandal Formation a free oil resource of 4,601x10^6 m^3 (P50) and a GIIP resource of 3,897x10^9 m^3 (P50) is estimated within the full range of reported thickness. Within the limited range in thickness of 100 m that is likely to be technical accessible a free oil resource of 1,722x10^6 m^3 (P50) and a GIIP resource of 1,404x10^9 m^3 (P50) is estimated.

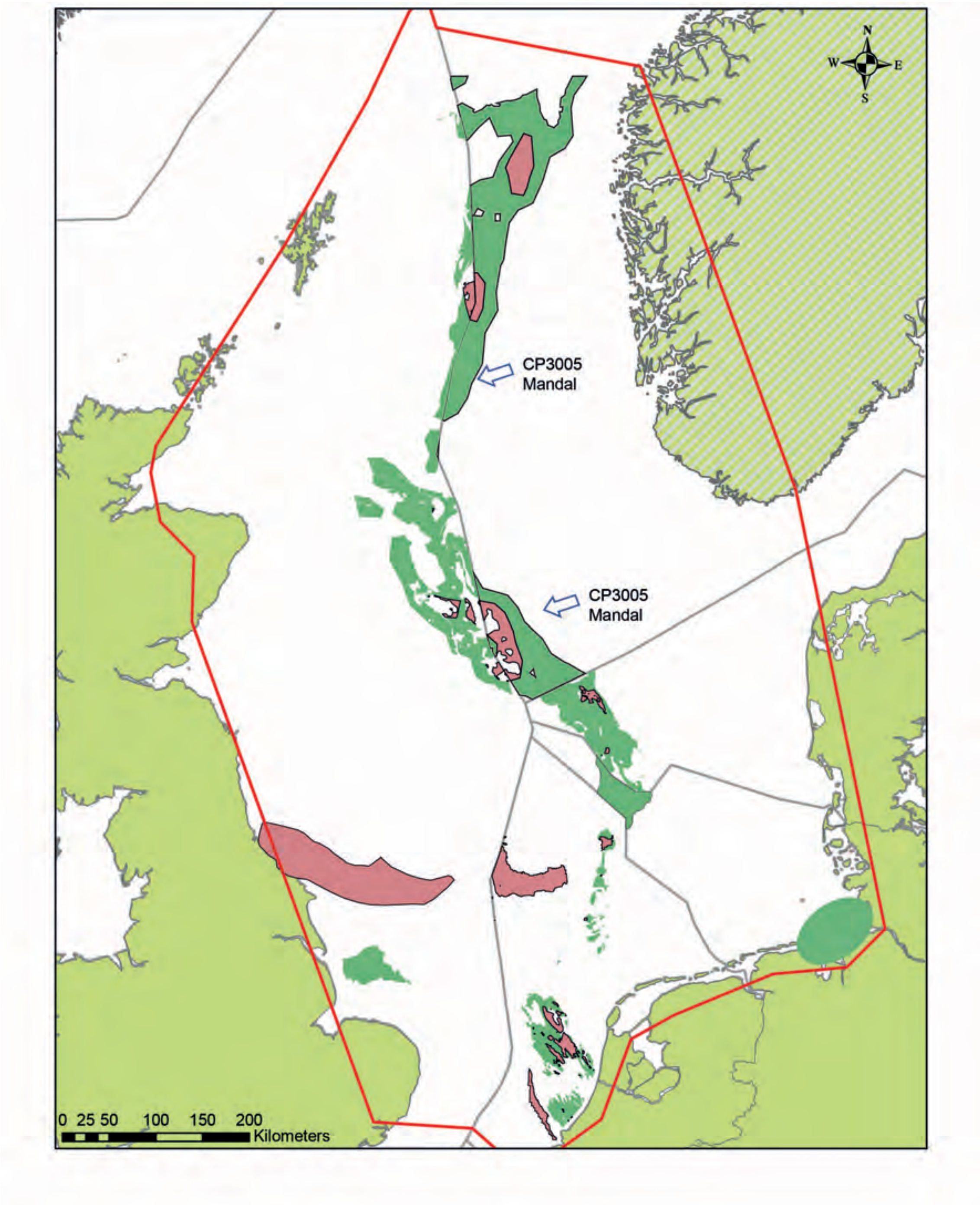

Figure 3-11 Oil and gas plays in the Norwegian part of the North Sea.

Table 3-18 Volume input data for the oil and gas plays in the Norwegian part of the North Sea.

Mandal Formation (CP 3005)						
Present day 1 – 5 km	Mean	Std	Min	Likeliest	Max	Unit
Oil mature area	17219	1291	9710		13815	km^2
Gas mature area	3007	226	577		821	km^2
Thickness (net)			20	126	1123	m
Mandal Fm 100 m			20	100	100	m

Table 3-19 Assessment results for the oil and gas plays in the Norwegian part of the North Sea.

		Sorbed Gas			Free Gas			GIIP			Free Oil		
CP	**Shale**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
		10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^6m^3	10^6m^3	10^6m^3
3005	Mandal 100 m	188	363	710	436	993	1907	782	1404	2399	343	1722	8667
3005	Mandal Fm	547	993	1815	1252	2735	5031	2211	3897	6272	908	4601	22607

3.3.6 NL

In the Netherlands the Carboniferous play in the Geverik Member (CP 3009) has a gas mature area of 2,416 km^2. No oil mature area has been identified (Table 3-20, Figure 3-12 Oil and gas plays in the Dutch part of the North Sea.The oil play of the Lower Jurassic Posidonia Shale Formation (CP 3010) is 3,505 km^2 and the gas play is 842 km^2 (Table 4-6). Well data indicate thicknesses for the Posidonia shale and Geverik Member between 26–58 m and 40–80 m, respectively (Table 3-20).

The assessed resources are tabulated in Table 3-21. In the Lower Carboniferous Geverik Member, a GIIP resource of 1,145x10^9 m^3 (P50) is estimated. In the Lower Jurassic Posidonia shale, a free oil resource of 403x10^6 m^3 (P50) and a GIIP of 414x10^9 m^3 (P50) is estimated.

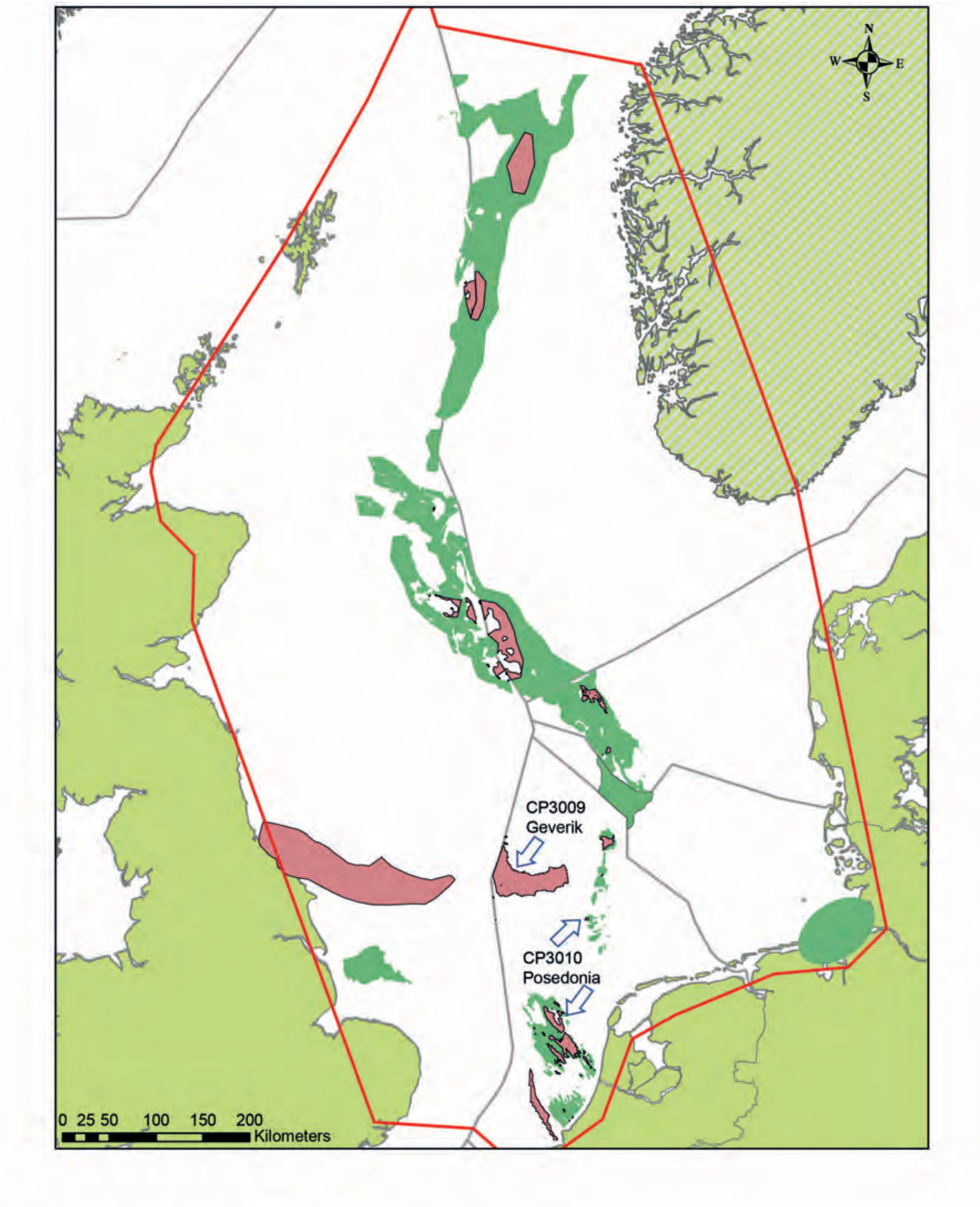

Figure 3-12 Oil and gas plays in the Dutch part of the North Sea.

Table 3-20 Volume input data for the oil and gas plays in the Dutch part of the North Sea.

Geverik Member (CP3009)						
Present day 1 – 5 km	Mean	Std	Min	Likeliest	Max	Unit
Area oil mature	–					km^2
Area gas mature	2416	121				km^2
Thickness			40	50	80	m
Posidonia Shale Formation (CP 3010)						
Present day 1 – 5 km	Mean	Std	Min	Likeliest	Max	Unit
Area oil mature	3505	263				km^2
Area gas mature	842	63				km^2
Thickness			26	41	58	m

Table 3-21 Assessment results for the oil and gas plays in the Dutch part of the North Sea.

		Sorbed Gas			Free Gas			GIIP			Free Oil		
CP	**Shale**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
		10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^6m^3	10^6m^3	10^6m^3
3009	Geverik Mbr; Bowland Eqv.	217	406	775	972	1716	2856	559	1245	2340		--	
3010	Posidonia Shale	62	117	222	310	450	757	138	314	609	80	403	2069

3.3.7 UK

Three shales have been recognized to hold a potential unconventional resource (Figure 3-13). The Carboniferous shale extends offshore from the east coast and has a gas mature play area of 7,814 km2; no oil mature play area has been identified (Table 3-22). The Posidonia shale equivalent in the Lias shales has an oil mature play estimated to have an area of 1,630 km2; no gas mature play area has been identified. The Kimmeridge Clay Formation has both an oil play and a gas play with estimated areas of 11,763 km2 and 699 km2 respectively (Table 3-22). Within the Kimmeridge Clay Formation the net shale thickness range between 1-1,123 m with a median of 123 m (Table 3-22). The thickness estimate is made from well penetrations within the oil mature area only and does not include Upper Jurassic sandstone interbeds nor the deeper gas mature parts.

For calculation of the resource, we have used both the reported net thickness distribution and a model thickness distribution that has a limited thickness range between 20–100 m (Table 3-22). The latter provide the oil and gas resource within a section of the shale that is likely to be technical accessible as we do not envision stacked horizontal well development offshore (see the Introduction).

The assessed resources are tabulated in Table 3-23. In the Carboniferous Bowland Formation, a GIIP resource of 5,114x109 m3 (P50) is estimated. In the Lower Jurassic Lias shale, only a free oil resource of 186x106 m3 (P50) is estimated as the play is not considered to be gas mature. In the Central Graben the Kimmeridge Clay Formation is considered both to be oil and gas mature with an estimated 11,077x106 m3 (P50) free oil and an estimated GIIP of 3,378x109 m3 (P50). This estimate is based on the full reported range in thickness of the Kimmeridge Clay. Assuming a “100 m thick slice” representing a more realistic development with respect to the resource then the shale resource is estimated to hold 3,139x106 m3 (P50) free oil and an estimated GIIP of 895x109 m3 (P50).

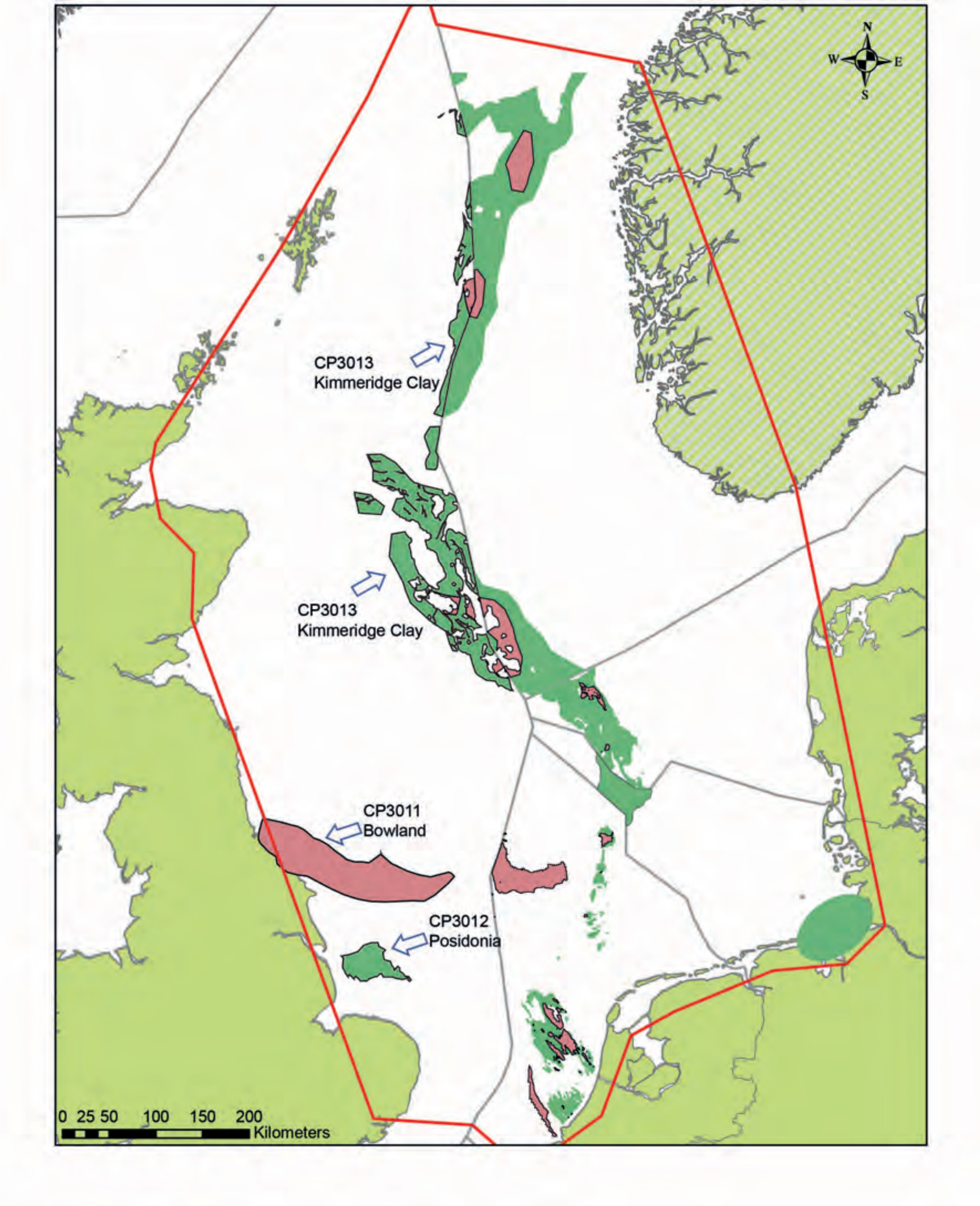

Figure 3-13 Oil and gas plays in the UK part of the sector of the North Sea.

Table 3-22 Volume input data for the oil and gas plays in the in the UK part of the North Sea.

Upper Bowland Shale (CP 3011)						
Present day 1 – 5 km	Mean	Std	Min	Likeliest	Max	Unit
Oil mature area	–					
Gas mature area	7814	781	5087		10541	km^2
Thickness (net)			17	39	110	m
Lias Group, Posidonia Eqv. (CP 3012)						
Present day 1 – 5 km	Mean	Std	Min	Likeliest	Max	Unit
Oil mature area	1630	122	1346		1914	km^2
Gas mature area	–					
Thickness (net)			24	43	57	m
Kimmeridge Clay (CP 3013)						
Present day 1 – 5 km	Mean	Std	Min	Likeliest	Max	Unit
Oil mature area	11763	882	9710		13815	km^2
Gas mature area	699	52	577		821	km^2
Thickness (net)			1	126	1123	m
KImmeridge Clay 100 m			20	100	100	m

Table 3-23 Assessment results for the oil and gas plays in the in the UK part of the North Sea.

		Sorbed Gas			Free Gas			GIIP			Free Oil		
CP	**Shale**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
		$10^9 m^3$	$10^9 m^3$	$10^9 m^3$	$10^9 m^3$	$10^9 m^3$	$10^9 m^3$	$10^9 m^3$	$10^9 m^3$	$10^9 m^3$	$10^6 m^3$	$10^6 m^3$	$10^6 m^3$
3011	Bowland Eqv.	523	1175	2646	1450	3633	8140	2591	5114	9585		--	
3012	Lias; Posidonia Shale eq.		--			--			--		37	186	930
3013	Kimmeridge Clay	232	849	2235	589	2239	6206	1370	3378	7491	1696	11077	68467
3013	Kimmeridge Clay 100 m	127	229	423	292	633	1170	518	895	1455	628	3139	15679

4 DISCUSSION

4.1 Conventional resources and reserves

The North Sea Basin is the most prolific petroleum basin in Europe with production extending back to the 1960s. The area is a mature basin from where more than 14 billion (14 x 10^9 m^3 or 14,000 x 10^6 m^3) oil equivalent (o.e) has been produced (see Figure 4-1 and Table 4-1). In the North Sea area, additional reserves (2P) of at least 2,900 x 10^6 m^3 o.e. and contingent resources (2C) of at least 1,500 x 10^6 m^3 have been estimated by the national agencies around the North Sea (see Figure 4-1 and Table 4-1). In addition, the estimates of prospective or *yet-to-find* resources within these institutions amounts to around 1,900 x 10^6 m^3 o.e (see Table 4-1). It should be noted that these values, particularly the yet-to-find resources, are however, based on a combination of many different estimates, each with different methodologies (see Section 2.1.1) and risking factors, that makes it difficult to directly compare and combine. It should also be noted that the totals shown in Table 4-1 are simply arithmetically added from each country estimate. In order to avoid a false sense of precision, they have been rounded up to the nearest hundred million.

The yet-to-find estimate presented here (1,900 x 10^6 m^3 o.e) for the combined North Sea area is about a half to one-third of the 3,000 x 10^6 m^3 o.e. (3,000 million m^3 at P50) yet-to-find estimated by USGS in 2005 (USGS, 2005), which covered an area comparable to the GARAH area of interest. The USGS (2005) estimate was based on a probabilistic approach with very wide range in field size distributions, making direct comparison somewhat difficult.

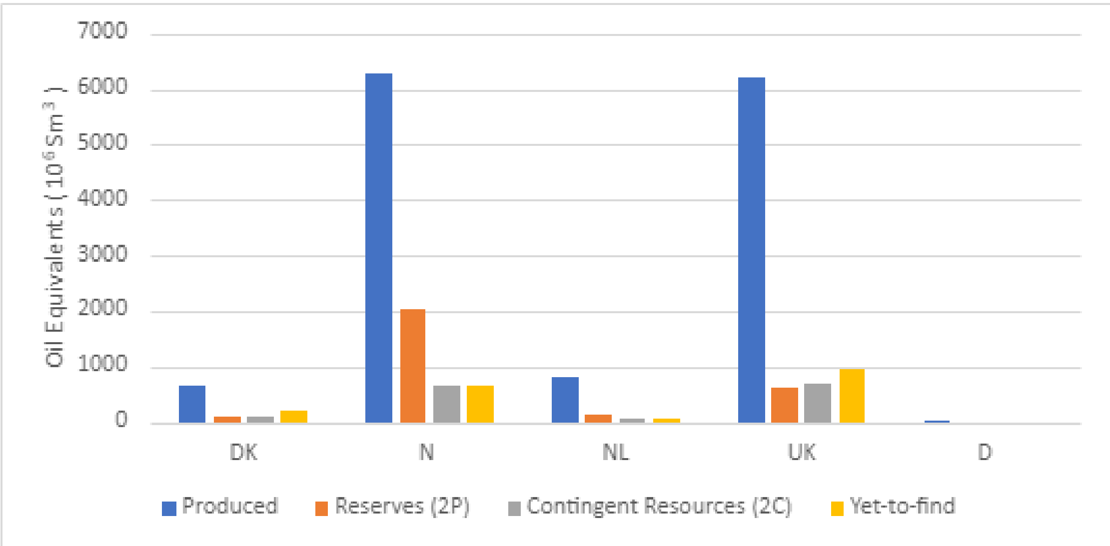

Figure 4-1 Produced, reserves, contingent resource and yet-to-find resources in the North Sea as estimated by the national agencies show in oil equivalent volumes. For details for each country and for difference in methodology see country-specific sections. For UK, the 2P and 2C reserves

categories for the North Sea are estimated from Figure 3-6 and Figure 3-7 and are therefore only approximate. Data used is also shown in Table 4-1.

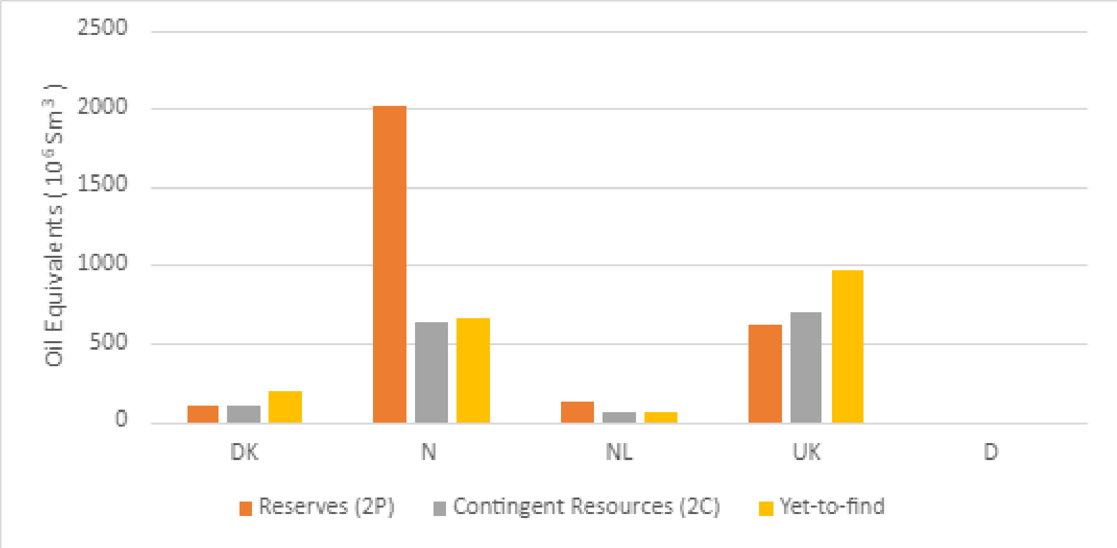

Figure 4-2 Reserves, contingent resource and *yet-to-find* resources in the North Sea as estimated by the national agencies show in oil equivalent volumes. For details for each country and for difference in methodology see country-specific sections. For the UK, the 2P and 2C reserves categories for the North Sea are estimated from Figure 3-6 and Figure 3-7 and are therefore only approximate. Data used is also shown in Table 4-1.

Table 4-1 General comparison of Produced, Reserves, Contingent resources and total Prospective/ yet-to-find conventional hydrocarbon resources in the North Sea. *Note that UK values have been read from charts and are thus an aproximation. †The Dutch yet-to-find numbers are based on a modelling approach that estimates the exploration potential for natural gas over the next 25 years. ¤Norwegian yet-to-find are based on risked probalistic modelling. [a] total UK and DK yet-to-find numbers from risked leads and plays plus additional risked resources (see Table 4-2).[b]Totals added arithmetically with no further weighting and rounded to the nearest hundred million

Country	**Produced**	**Reserves (2P)**	**Contingent Resources (2C)**	**Yet-to-find**
	10^6 Sm^3 o.e.	10^6 Sm^3 o.e.	10^6 Sm^3 o.e.	10^6 Sm^3 o.e.
DE	10			
DK	643	96	96	190[a]
NK	6280	2023	637	665¤
NL	815	134	61	58†
UK	6201	620*	703*	969[a]
TOTAL[b]	14000	2900	1500	1900

The main issue in attempting to understand conventional hydrocarbon resources and reserves across the GARAH area of interest is the different systems of assessment used. In some cases, it is possible to make relatively direct comparisions. For example, both the UK and Danish estimates of prospective resources use risked prospects and leads and so can be cautiously compared, as in Table 4-2. However, this is not the case for the other countries in the study area where methodology varies widely.

Table 4-2 Comparison of prospective resources in Danish and UK North Sea from prospect and lead inventories, and additional resources.

Country	Area	Prospects and leads risked P50 (x 10^6 m^3)	Possible additional resources risked P50 (x 10^6 Sm^3)
DK	**NS**	**184**	**6**
		Prospects and leads with cut-offs (P50 million m^3)	Possible additional resources with cut-offs (P50 million m3)
UK	NNS	79	127
	CNS	270	223
	MNSH	n/a	79
	SNS	64	127
	NS*	**413**	**556**

Overall, it is clear from all estimates that production of conventional hydrocarbons in the North Sea has been dominated by the UK and Norwegian sectors. These countries also estimate the largest reserves and potential future resources (see Figure 4-2).

4.2 Plays

As with the conventional hydrocarbon resource/reserve assessments, each of the countries in the GARAH study area uses a different approach to define their plays and associated confidence levels. Although the general definition of a play as "an area where the geological factors that are a prerequisite for the generation and trapping of hydrocarbons coexist" is agreed, a variety of factors appear to influence the decision to define a play. These include, for example: whether the play is well-understood elsewhere in the area; the amount of data (including geophysical and well data) available to characterise the play or conceptual play; geological limits for risking; varying importance of play components such as reservoir versus source distribution; and various non-geological factors such as distance from infrastructure or cost.

Furthermore, the North Sea study area is a large and structurally/geologically complex area, and many working petroleum systems show evidence for significant hydrocarbon migration and complex evolution over time. This makes predicting unproven or conceptual plays more difficult, with the resulting concepts neccesarily cautious. We also observe that because the basin is mature, much of the data acquistition and focus has been focused on maximising what are the well-understsood and highly productive petroleum systems and plays (for example, those sourced by the Kimmeridge Clay Formation, or the Rotliegend plays in the southern North Sea). Also, because shallower plays are generally easier to explore, test and produce, potential plays in deeper stratigraphy (>3 km) may also be overlooked. Overall, the main trend observed from the harmonisation of individual play maps is the lack of information on the pre-Permian. In particular, the NPD play mapping combines all pre-Triassic reservoirs (and some Triassic) into one category within the Norwegian sector. In the GARAH project, this can be seen, for example, in the Triassic and Permian Rotliegend maps in the Norwegian sector, as shown in Figure 11-10 and Figure 11-12, where both the proven and the large conceptual play areas extending into the Danish sector are described as "Devonian, Carboniferous, Permian and possible Triassic" (see GARAH GIS for full metadata).

Another example is shown in in the play map compiled for the Carboniferous, where potential plays are identified only from the UK and NL sectors, although various publications consider Carboniferous material (up to 6 km thick in the southern North Sea) with source/reservoir potential is likely present at depth across the southern North Sea Basin into the Danish sector, and within the central Graben of the UK/NK cross-border region (although it has only been encountered in wells within the UK sector) (see Figure 11-13 in Appendix D; Bruce and Stemmerik, 2003; Kombrink et al., 2010, ter Borgh et al., 2018).

Play definitions also vary in the levels of detail relating to economic importance. This is clear, for example, in the subdivision of UK plays into Eocene and lower Eocene reservoir plays, due to numerous, well-understood reservoir facies in these intervals in the UK sector which are economically important (see Figure 11-2 and Figure 11-3 and the GARAH GIS). In contrast, the NK plays show only

Eocene proven and mature plays, despite the same geological formations likely extending into the Nowegian sector.

4.3 Knowledge Gaps: Conventional

The GARAH assessment of the national reserve and resource estimation and the subsequent harmonisation has faced challenges in synthesizing resource data which were produced using differing standards and units. We have made efforts to harmonise the national assessments, but we strongly recommend that a higher degree in alignment of reporting is made in countries bordering the North Sea to make more consistent regional assessments. In particular, if all assessments could be converted into the same units while being calculated, this would remove errors propagating from differing standards of conversion factors such as gas to oil equivalent. While these conversions vary due to differences in physical properties of hydrocarbons across the North Sea (e.g. Groningen gas in the Netherlands compared to Norwegian crude), conversion during assessment would be most accurate.

The national assessments are also sometimes not linked to a specific geographical area. This can be seen for Germany, where resources are not separated for the onshore and offshore. In the UK, reporting of reserves and contingent resources are published for the entire UK continental shelf rather than for sub-areas, as is done for prospective resources. Recognition of the North Sea as a unique hydrocarbon producing area would be most useful in any further cross-border estimates; its location bordering almost all hydrocarbon producing countries in northern Europe makes it an important area to analyse separately.

In a geological sense, most of the knowledge gaps in understanding the potential resources of the North Sea appear to relate to a relatively poorer understanding of deeper intervals and thus a lack of information to create play-based assessments for potential resources or *yet-to-find*. This is particularly the case where shallower working petroleum systems have dominated production; reducing the impetus to acquire data targeting underlying intervals. As a result, with the exception of the prolific Permian/Carboniferous plays in the southern North Sea, the pre-Triassic is relatively under-explored in large parts of the North Sea area, and little seismic or well data is available for study.

For some countries and factors, lack of publicly available data hinders regional assessment. In the GARAH study, this was most apparent for the German sector, where no information was available relating to potential hydrocarbon plays, or detail on prospective resources. In the UK, information on shallow gas in the North Sea area was not publicly available.

The uncertainties in actual reserves and resource relating to differences in reporting and methods, as well as a lack of detailed published estimates in some areas, hampers planning relating to conventional hydrocarbon extraction, as well as alternative uses in the GARAH North Sea Area. Similarly, while play-based assessments better capture the geological reasoning behind hydrocarbon assessments, these are limited when influenced by the location of country borders and associated changes in detail and importance.

4.4 Unconventional plays and ressources

Ten potentially prolific oil plays in the North Sea have identified with a *yet-to-find* resource potential (P50) of 6,648 x 10^6 m^3 oil and nine gas plays have a gas *yet-to-find* resource potential of 9,344 x 10^9 m^3 gas (Table 4-3). This estimate includes the resource estimated for a 100 m thick Upper Jurassic - lowermost Cretaceous shale unit and thus excludes the resource base calculated in the >1 km thick shale interval in UK and Norway.

The OIIP here is evaluated merely on free oil content. Absorbed oil is not considered in the modelling and therefore the estimates could be considered conservative. OIIP might thus be considerable higher.

The oil resource is mostly located in the Upper Jurassic- lowermost Cretaceous shales in the UK and Norwegian part of the North Sea owing to its vast regional coverage and thickness. The gas resource is dually distributed in the Carboniferous Bowland equivalent shales located in the Netherlands and in the UK offshore area and in Jurassic shales in UK and NK (Figure 4-3, Table 4-3).

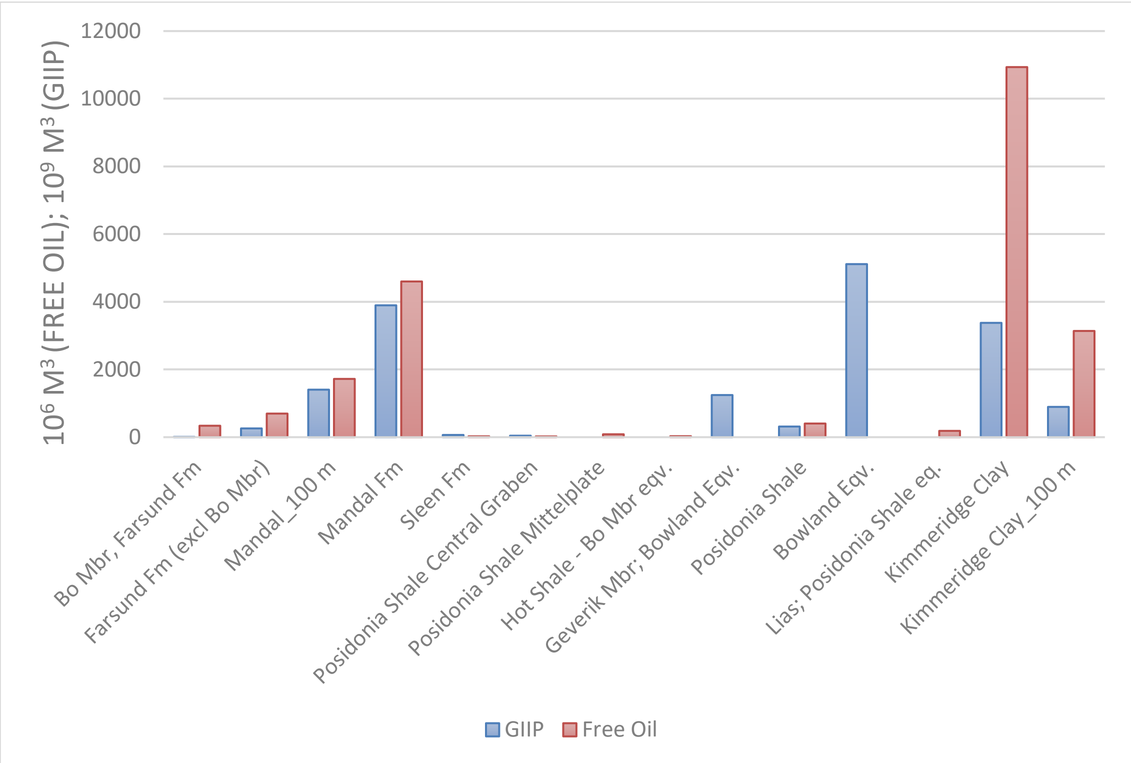

Figure 4-3 Assessment of the unconventional yet-to find free Oil (P50) and GIIP (P50) resource for the GARAH study area.

Table 4-3 Overview of the unconventional *yet-to find* free Oil and GIIP assessment of the 10 oil plays and 9 gas plays within the assessed 12 shales.

			Sorbed Gas			Free Gas			GIIP			Free Oil		
CP	**Basin**	**Shale**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
			10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^9m^3	10^6m^3	10^6m^3	10^6m^3
3002	DK Central Graben	Bo Mbr, Farsund Fm	1	2	4	0	1	2	2	3	5	67	338	1761
3003	DK Central Graben	Farsund Fm (excl Bo Mbr)	33	67	133	72	181	366	139	259	453	138	697	3506
3005	N Central Graben	Mandal-100 m	188	363	710	436	993	1907	782	1404	2399	343	1722	8667
3005	N Central Graben	Mandal Fm	547	993	1815	1252	2735	5031	2211	3897	6272	908	4601	22607
3006	D Central Graben	Sleen Fm	6	14	31	23	49	97	36	66	115	5	26	137
3007	D Central Graben	Posidonia Shale	4	11	24	11	31	71	21	44	86	4	23	119
3007	D Mittel-plate	Posidonia Shale		--			--					17	86	433
3008	D Central Graben	Hot Shale - Bo Mbr eqv.		--			--					6	29	163
3009	NL Central Graben	Geverik Mbr; Bowland Eqv.	217	406	775	972	1716	2856	559	1245	2340		--	
3010	NL Central Graben	Posidonia Shale	62	117	222	310	450	757	138	314	609	80	403	2069
3011	North Sea	Bowland Eqv.	523	1175	2646	1450	3633	8140	2591	5114	9585		--	
3012	North Sea	Lias; Posidonia Shale eq.		--			--					37	186	930
3013	North Sea	Kimmeridge Clay	232	849	2235	589	2239	6206	1370	3378	7491	1696	10936	66442
3013	North Sea	Kimmeridge Clay_100 m	127	229	423	292	633	1170	518	895	1455	628	3139	15679

4.5 Sensitivity analysis for Unconventional assessment

Table 4-4 presents an overview of the main parameters that contribute to the uncertainties in the Monte Carlo simulations. For the GIIP and free oil estimate the main contributing factor is the saturation, porosity and thickness. For a few plays also the area uncertainty contributes substantially to overall uncertainty in the Monto Carlo simulations. For the sorbed gas the main uncertainties across the different plays are the *Langmuir Volume* followed by the thickness, whereas for the free gas, gas saturation followed by the thickness and porosity are the dominant parameters.

Table 4-4 Uncertainty analysis for GIIP and Free Oil determination. Only the main contributors to the uncertainty analysis are shown. >50%, 10–25% and 5–10% indicate level of approximate contribution. Colour is for easy identification of main input parameters. Green: *Langmuir Volume*, Blue: Thickness, Red: Saturation (gas or oil), yellow: Porosity, Grey: Area.

				Sorbed Gas			Free Gas			GIIP			Free Oil		
CP	**Basin**	**Countr**	**Shale**	>50%	10-25%	5-10%	>50%	10-25%	5-10%	>50%	10-25%	5-10%	>50%	10-25%	5-10%
3002	DK Central Graben	Dk	Bo Mbr, Farsund Fm	Vlang	Thickness		Saturation	Thickness		Vlang	Thickness	Saturation	Saturation		
3003	DK Central Graben	Dk	Farsund Fm (excl Bo Mbr)	Vlang	Thickness		Saturation	Thickness	Porosity	Saturation	Thickness	Porosity	Saturation	Porosity	
3005	N Central Graben	N	Mandal Fm	Vlang		Thickness	Saturation	Porosity	Thickness	Saturation	Porosity	Vlang	Saturation	Porosity	Thickness
3005	N Central Graben	N	Mandal_100 m	Vlang			Saturation	Porosity	Vlang	Saturation	Porosity		Saturation	Porosity	
3006	D Central Graben	D	Sleen Fm	Vlang	Thickness	Area	Thickness	Area	Porosity	Thickness	Area	Porosity	Saturation	Thickness	Area
3007	D Central Graben	D	Posidonia Shale Central Graben	Vlang	Area	Thickness	Saturation	Area	Porosity	Saturation	Area	Porosity	Saturation		Area
3007	D Mittelplate	D	Posidonia Shale Mittelplate		--			--			--		Saturation		
3008	D Central Graben	D	Hot Shale - Bo Mbr eqv.		--			--			--		Saturation	Thickness	
3009	NL Central Graben	NL	Geverik Mbr; Bowland Eqv.	Vlang		Thickness	Saturation	Porosity	Thickness	Saturation	Porosity	Vlang		--	
3010	NL Central Graben	NL	Posidonia Shale	Vlang		Thickness	Saturation	Porosity	Thickness	Saturation	Porosity	Vlang	Saturation		
3011	North Sea	UK	Bowland Eqv.	Vlang	Thickness		Saturation	Thickness	Porosity	Saturation	Thickness	Porosity		--	
3012	North Sea	UK	Lias; Posidonia Shale eq.		--			--			--		Saturation		
3013	North Sea	UK	Kimmeridge Clay	Thickness	Vlang		Thickness	Saturation	Porosity	Thickness	Saturation		Saturation	Thickness	Porosity
3013	North Sea	UK	Kimmeridge Clay_100 m	Vlang			Saturation	Porosity		Saturation	Porosity	Vlang	Saturation		

The sensitivity study shows that many of the main contributing factors (i.e. oil and gas saturation, V_L, porosity) are the least data supported parameters for the investigated shales. At this initial stage if unconventional assessments in the North Sea, there is very limited constraint of HC resource specific data for the individual shale plays. Therefore, these *yet-to-find* assessments follow analogue approaches and have a large uncertainty.

4.6 General chance of success description for Unconventional resources

The *yet-to-find* resource presented here is un-risked and no attempts have been made to perform a ranking of the resource within the individual plays. In our selection of assessed shales, we focussed only on the higher resource classes (Class 1 and 2, c.f. Table 3-13) and have omitted hypothetical plays and/or plays with uncertain properties (Class 3 and “no” in Table 3-13). Other relevant factors, such as mineralogy and in-situ stress conditions have also not been considered in this assessment and could have a major impact on the potential recoverability of the resource. In consequence, we are only describing plays that have a close resemblance to producing North American shale plays i.e. they belong to a proven petroleum systems in which they are source rocks or a highly likely source rock and that they have CP values within the accepted range of producing north American shales. We therefore assume the same play risk for all assessed plays.

With respect to possible technical recovery factors 10% is a common assumption in lack of detailed, *in-situ* petrophysical parameters (Stueck et al., 2015). For the very thick Jurassic-Cretaceous shales in NK and UK, which would provide unrealistically large resource estimates, we limited the net pay zone to a 100 m unit.

4.7 Knowledge gaps: Unconventional

The knowledge base for the description and subsequent assessment of the unconventional resource in the North Sea is highly variable.

<u>Mapping</u>
Not all of the GARAH area was covered by 3D basin modelling - most of the area was covered only by regional scale maps based on 2D lines. To enhance the reliability of the assessment we used shale volume estimated based on 3D seismic data when possible. In terms of stratigraphy notably the Jurassic has the best data coverage followed whereas the Carboniferous has the poorest data coverage.

<u>Capacity parameters</u>
The shales were generally well-characterised with traditional source rock screening parameters such as TOC and Rock Eval data such as T_{max} and S_2 yield. Laboratory measurements on specific capacity related parameters such as *Langmuir Volume* and mineralogy were generally lacking, and a target research program would have to be made to collect such data.

<u>*In-situ* measurements</u>
Measurement from the source rock itself such a pressure, temperature and saturation (oil and gas) not to mention flow test were not availed for this study. Without such data a critical evaluation of the plays and the assessed resources cannot be made safely.

4.8 Comparison to resource assessments based on the 3D pilot model

Within the GARAH project unconventional resources have also been assessed within in a 3D petroleum system modelling pilot study (Delivery 2.4 and Delivery 2.5). These studies followed a 3D basin modelling approach and as such the resource estimates cannot be compared directly as they differ in method and scope. The 3D pilot study area is also limited to the Danish, German and northern part of the Dutch sectors of the Central Graben.

For the unconventional assessment of the Danish Farsund and the German Posidonia shale the area estimated is similar and this allows the GIIP to be compared between the two methods. The two estimates compare relatively well: $178x10^9$–$259x10^9$ m^3 and $22x10^9$–$44x10^9$ m^3, respectively for the GARAH Delivery Report 2.4 – Delivery Report 2.3 range for the two shales and are thus within the expected uncertainties given the different methodological approaches. For OIIP a comparison of the two approaches is not meaningful, due to different handling of sorbed oil and free oil content. The main added value of the 3D model is that the uncertainties following the EUOGA assessment approach is reduced as the definitions of the shale volumes are improved when the data is provided from a 3D model as compared more traditional approaches.

For the conventional assessment the main advantage of using the 3D pilot model is the ability to examine and report the resources in a play-based manner that also allow different migration scenarios to be analysed. However, the actual resources estimate depends on many different aspects and cannot be compared directly to the *yet-to-find* resource estimated based on a prospects and lead inventory.

5 IMPLICATIONS

Since the inception of the GARAH project in 2018, the status of hydrocarbon extraction and exploration has rapidly changed for individual countries and across the EU. The IEA (2021) publication of a roadmap to zero emissions by 2050 emphasises a path with no new hydrocarbon exploration in the North Sea, or elsewhere.

In order for policy decisions to be made on how to manage hydrocarbon resources, consistent and reliable cross-border estimates of total reserves and potential resources are required, as were carried out in the GARAH project. The GARAH compilation for the North Sea area indicates significant reserves and potential resources (in the order of hundreds of billions of cubic metres of oil equivalent) in both conventional and unconventional plays. These reserves and resources can be fed into the planning and policy decisions of member states, particularly in terms of weighing up the potential for future licensing rounds of existing and new schemes. The knowledge gaps identified for the conventional and unconventional resources are also important in terms of fully understanding all potential resources, and in commercial terms of understanding where member states may target funding and/or joint work with industry, if at all.

For the offshore North Sea, the GARAH project introduces new potential plays to the study areas in the form of the unconventional shale and oil plays. Our evaluation show that these hold a significant resourse that could be unlocked from existing offshore platforms once conventional resources are exhausted, and thus may extend field life and postpone the awaiting abandonment phase, as the unconventional plays typically occur where production is already taking place.

One route to a net-zero outcome is to continue to extract and explore for domestic gas in the North Sea, which results in a lower carbon footprint than when gas is imported from further afield. Our analyses show that, if such production and exploration is to continue, it would be most valuable to take a cross-border approach to fully understand the geological basis of potential plays and petroleum systems, and to make best use of North Sea resources and infrastructure.

Many of the conventional and unconventional plays collated in this study are also important in terms of their potential contribution to alternative energy security: for carbon capture, hydrogen and other energy storage, and even offshore geothermal potential. The results of this resource assessment are combined with a catalogue of the multiple-use (or sequential-use) potential and impacts of hydrocarbon reservoirs (GARAH Delivery Report 2.6) to further enable the European community to understand the most efficient, sustainable, and climate-friendly use of the subsurface.

6 CONCLUSIONS

In the updated hydrocarbon assessment of the North Sea, we have implemented and extended standards and tools for HC assessment by building on the former EUOGA methods, correlating source formations in offshore regions and harmonised conventional play maps.

The assessment of the conventional prospective resources is made quantitatively based on a harmonisation of the national reserve and resource estimation and qualitatively following a play-based approach.

The harmonization of the national conventional assessment show that there are significant reserves, contingent resources and prospective resources left in the North Sea. More than 14 billion m^3 oil equivalents have been produced in the North Sea and additional reserves (2P) amount to least 2.9×10^9 m^3 o.e., and contingent resources (2C) of at least 1.5×10^9 m^3. Based on the national agencies it is estimated that the of *yet-to-find* resources amount to around 1.9×10^9 m^3 o.e.

The qualitative assessment of the North Sea has resulted in the construction of a total of 13 major conventional play maps. The play maps provide one of the first main North Sea-wide efforts to compile such maps from individual country interpretations, and thus represent a major step in planning of the use of the North Sea subsurface both in terms of future licences rounds, alternative use and risking.

The assessment of the *yet-to-find* resource associated with the unconventional plays in the North Sea Basin show that this resource is significant. Ten potentially prolific oil plays in the North Sea have been identified with a *yet-to-find* resource potential (P50) of $6{,}648 \times 10^6$ m^3 oil and nine gas plays have been identified with a gas *yet-to-find* resource potential of $9{,}344 \times 10^9$ m^3 gas. This estimate includes the resource estimated for a 100 m thick Upper Jurassic - lowermost Cretaceous shale unit and thus excludes the resource base calculated in the >1 km thick shale interval in UK and Norway. The oil resource is mostly located in the Upper Jurassic- lowermost Cretaceous shales in the UK and Norwegian part of the North Sea owing to its vast regional coverage and thickness. The gas resource is dually distributed in the Carboniferous Bowland equivalent shales located in the Netherlands and in the UK offshore area and in Jurassic shales in UK and N.

The unconventional resource estimate is based on Monte Carlo simulations following the EUOGA method. The main parameters that contribute to the uncertainties are the saturation, porosity and thickness and the sorption parameters such as the *Langmuir Volume*.

Currently, no exploration for unconventional resource occurs in the North Sea and, in some areas such as the Danish part of the North Sea, the current legislation aims cut off of oil and gas production by 2050, and does not permit new licencing rounds. The *yet-to-find* resource base reported here may, however, extend field life and postpone abandonment phase as the unconventional plays are located typically within areas where production occurs. A better understanding of the potential resource base also has value in decarbonising energy in the North Sea (blue Hydrogen) and can support the shift from coal to gas.

The uncoventional assement based on the EUOGA method has a direct exchange with the 3DGEO-EU project and demonstrate added value of the novel harmonized 3D models both for the conventinal and unconventinal assesments.

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8 APPENDIX A. CAPACITY PARAMETERS (CP) FOR SHALE PLAYS

3001

GARAH Capasity Parameters					Source (Ref.list)	Comments
Shale Name:	Alum ShaleFormation					
Country:	Denmark					
Age (Age):						
Age (Epoch):	Furongian				1	Middle Cambrian to Lower Ordovician
Basin:	North Sea				2	
Chance of success parameters					**Source (Ref.list)**	**Comments**
Mapping status	Moderate				2	
Sedimentary variability	Low				1	
Structural complexity	Moderate				2	
Available HC data	Poor				3	
Proven source rock	Possible				8	Proven SR in Baltic Basin only
Maturity variability	Moderate				2	
Depth	Average				2	
Mineral composition	Unknown					no data for North Sea
Detailed parameter list	**Min**	**Max**	**Mean**	**Distribution**	**Source (Ref.list)**	**Comments**
1. Area (km2)					2	Distribution maps provided via EUOGA project
2. Thickness (gross, m)	20	180	**80**	Triangular	**2**	Distribution maps provided via EUOGA project
2a. Thickness (net, m)	20	150	**75**	Triangular	**2**	
2b. Net/Gross (%)	85	100	**90**	Triangular	**2**	
3. Depth (m)	1500	7000	**4.000**	Triangular	**2**	Distribution maps provided via EUOGA project
4. Density (g/cm3)	2,3	2,6	**2,45**	Triangular	***4***	
5. TOC (%)	0	17	**9**	Triangular	***3***	Distribution maps provided via EUOGA project
6. Porosity (%)	4	12	**7**	Triangular	***11***	correlate with TOC
7. Maturity (%VR) or graptolite equivalent	1,8	3	**2,5**	Triangular	***2, 10***	Distribution maps provided via EUOGA project
8. Reservoir pressure (psi)	2945	8300	**7106**	Triangular		assumed
9. Reservoir Temperature (°C)	64	202	**135**	Triangular		assumed
10. Gas saturation (%)(Sg)	15	80	**50**	Triangular		assumed
11. Oil Saturation (%) So)			0			assumed
12. Gas generation mgHC/g TOC (Hydrogen index)	360	560	**470**	Triangular	***9***	
13. Kerogen type			**II**		***2***	prior to type III
14. Sorption capacity VReq. - 1,9 % (mmol/g)	0,12	0,31	**0,2**	Triangular	***5***	
15. Matrix permeability (nDarcy)	7	45	**40**	Triangular	***6***	
16. Adsorbed gas storage capacity (scf/ton)	30	75	**50**	Triangular	***5***	
17. Compressibility factor (z)	0.76	1	**1,01**	Triangular		assumed
18a. Bg - Gas formation volume factor	0.0089	0.0183	**0.0133**	Triangular		assumed
18b. Bo - Oil formation volume factor						
19. Langmuir Pressure (pL, psi)	432	700	**435**	Triangular	**5**	
20. Langmuir Volume (nL, scf/ton)	20	63	**36**	Triangular	**5**	
21. Bulk mineral constituents XRD						
21a Total Clay content (%)	40	70	**55**	Triangular	**4, 7**	
Content of smectite						
Content of Illite & Mica						
Content of Kaolinite						
21b Quartz-feldspars content (%)	0	30	**40**			
21c C arbonate content (%)	0	10	5	Triangular		

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GARAH Capacity Parameters		Source (Ref.list)	Comments
Shale Name:	Bo Member in the Farsund Formation		Upper Jurassic to lower Cretaceous
Country:	Denmark		
Age (Age):			
Age (Epoch):	Upper Jurassic	1	
Basin:	North Sea		
Chance of success parameters		**Source (Ref.list)**	**Comments**
Mapping status	Good	2	Proven SR in North Sea Basin
Sedimentary variability	Moderate		
Structural complexity	Moderate		
Available HC data	Moderate		
Proven source rock	Proven		
Maturity variability	Moderate		
Depth	Average		
Mineral composition	Poor		

Detailed parameter list	Min	Max	Mean	Distribution	Source (Ref.list)	Comments
1. Area (km2)						
2. Thickness (gross, m)	15	50	**30**	triangular	***1, 3***	Average estimated
2a. Thickness (net, m)	15	45	**20**	triangular	***1***	
2b. Net/Gross (%)	90	100	**95**	triangular		
3. Depth (m)	1000	5000	**2500**	triangular		
4. Density (g/cm3)						
5. TOC (%)	3	15	**6**	triangular	***2, 4***	Average estimated
6. Porosity (%)						
7. Maturity (%VR) or graptolite equivalent						
8. Reservoir pressure (psi)						
9. Reservoir Temperature (°C)						
10. Gas saturation (%)(Sg)						
11. Oil Saturation (%) So)						
12. Gas generation mgHC/g TOC (Hydrogen index)	200	600	**500**	triangular	***2***	Average estimated
13. Kerogen type	I/II	II/III	**II**		***2***	trace type III and I
14. Sorption capacity VReq. - 1,9 % (mmol/g)						
15. Matrix permeability (nDarcy)						
16. Adsorbed gas storage capacity (scf/ton)						
17. Compressibility factor (z)						
18a. Bg - Gas formation volume factor						
18b. Bo - Oil formation volume factor						
19. Langmuir Pressure (pL, psi)						
20. Langmuir Volume (nL, scf/ton)						
21. Bulk mineral constituents XRD						
21a Total Clay content (%)						
Content of smectite						
Content of Illite & Mica						
Content of Kaolinite						
21b Quartz-feldspars content (%)						
21c Carbonate content (%)						
22. Brittleness indicators						
22a Poisson's ratio						
22b Young's modulus						
22c other indicators						

3002

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GARAH Capasity Parameters					Source (Ref.list)	Comments
Shale Name:	Farsund Formation					Upper Jurassic to lower Cretaceous
Country:	Denmark					
Age (Age):						
Age (Epoch):	Upper Jurassic				1, 3	
Basin:	North Sea					

3003

Chance of success parameters		Source (Ref.list)	Comments
Mapping status	Good	2	Proven SR in North Sea Basin
Sedimentary variability	Moderate		
Structural complexity	Moderate		
Available HC data	Moderate		
Proven source rock	Proven		
Maturity variability	Moderate		
Depth	Average		
Mineral composition	Poor		

Detailed parameter list	Min	Max	Mean	Distribution	Source (Ref.list)	Comments
1. Area (km2)						
2. Thickness (gross, m)	20	1000	**300**	triangular	*1*	Average estimated
2a. Thickness (net, m)	20	1000	**300**	triangular		
2b. Net/Gross (%)	80	100	**95**	triangular		
3. Depth (m)	1000	5000	**2500**	triangular		
4. Density (g/cm3)						
5. TOC (%)	0,5	15	**3**	triangular	*4*	Average estimated
6. Porosity (%)						
7. Maturity (%VR) or graptolite equivalent						
8. Reservoir pressure (psi)						
9. Reservoir Temperature (°C)						
10. Gas saturation (%)(Sg)						
11. Oil Saturation (%) So)						
12. Gas generation mgHC/g TOC (Hydrogen index)	100	600	**400**	triangular		Average estimated
13. Kerogen type	I/II	II/III	**II-II/III**			trace type III and I
14. Sorption capacity VReq. - 1,9 % (mmol/g)						
15. Matrix permeability (nDarcy)						
16. Adsorbed gas storage capacity (scf/ton)						
17. Compressibility factor (z)						
18a. Bg - Gas formation volume factor						
18b. Bo - Oil formation volume factor						
19. Langmuir Pressure (pL, psi)						
20. Langmuir Volume (nL, scf/ton)						
21. Bulk mineral constituents XRD						
21a Total Clay content (%)						
Content of smectite						
Content of Illite & Mica						
Content of Kaolinite						
21b Quartz-feldspars content (%)						
21c Carbonate content (%)						
22. Brittleness indicators						
22a Poisson's ratio						
22b Young's modulus						
22c other indicators						

REFERENCE LIST :

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GARAH Capasity Parameters		Source (Ref.list)	Comments
Shale Name:	Fjerritslev Formation		Lower Jurassic
Country:	Denmark		
Age (Age):			
Age (Epoch):	Lower Jurassic	1	
Basin:	North Sea		

3004

Chance of success parameters		Source (Ref.list)	Comments
Mapping status	Poor	1	Proven SR in North Sea Basin outside Denmark
Sedimentary variability	Moderate		
Structural complexity	Moderate		
Available HC data	Moderate		
Proven source rock	Proven		
Maturity variability	Moderate		
Depth	Average		
Mineral composition	Poor		

Detailed parameter list	Min	Max	Mean	Distribution	Source (Ref.list)	Comments
1. Area (km2)						
2. Thickness (gross, m)	0	300	**100**	triangular	1	Average estimated
2a. Thickness (net, m)	0	300	**100**	triangular		
2b. Net/Gross (%)	80	100	**95**	triangular		
3. Depth (m)	3000	5000	**3500**	triangular		
4. Density (g/cm3)						
5. TOC (%)	0,5	2,5	**2**	triangular	2	Average estimated
6. Porosity (%)						
7. Maturity (%VR) or graptolite equivalent						
8. Reservoir pressure (psi)						
9. Reservoir Temperature (°C)						
10. Gas saturation (%)(Sg)						
11. Oil Saturation (%) So)						
12. Gas generation mgHC/g TOC (Hydrogen index)	100	400	**300**	triangular		Average estimated
13. Kerogen type	I/II	II/III	**II-II/III**			trace type III and I
14. Sorption capacity VReq. - 1,9 % (mmol/g)						
15. Matrix permeability (nDarcy)						
16. Adsorbed gas storage capacity (scf/ton)						
17. Compressibility factor (z)						
18a. Bg - Gas formation volume factor						
18b. Bo - Oil formation volume factor						
19. Langmuir Pressure (pL, psi)						
20. Langmuir Volume (nL, scf/ton)						
21. Bulk mineral constituents XRD						
21a Total Clay content (%)						
Content of smectite						
Content of Illite & Mica						
Content of Kaolinite						
21b Quartz-feldspars content (%)						
21c Carbonate content (%)						
22. Brittleness indicators						
22a Poisson's ratio						
22b Young's modulus						
22c other indicators						

REFERENCE LIST :

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GARAH Capasity Parameters		Source (Ref.list)	Comments
Shale Name:	Mandal Formation		
Country:	Norway		
Age (Age):			
Age (Epoch):	Upper Jurassic		
Basin:	North Sea		

3005

Chance of success parameters		Source (Ref.list)	Comments
Mapping status	Poor		
Sedimentary variability	Moderate		
Structural complexity	Moderate		
Available HC data	Moderate		
Proven source rock	Proven		
Maturity variability	Moderate		
Depth	Average		
Mineral composition	Poor		

Detailed parameter list	Min	Max	Mean	Distribution	Source (Ref.list)	Comments
1. Area (km2)					2	
2. Thickness (gross, m)	0	1000	**300**	triangular	***2***	Average estimated
2a. Thickness (net, m)	20	800	**600**	triangular	***2***	
2b. Net/Gross (%)	80	100	**95**	triangular	***2***	
3. Depth (m)	1000	5000	**3000**	triangular	***2***	
4. Density (g/cm3)						
5. TOC (%)	0,5	2,5	2	triangular	***1,2***	Average estimated
6. Porosity (%)						
7. Maturity (%VR) or graptolite equivalent						
8. Reservoir pressure (psi)						
9. Reservoir Temperature (°C)						
10. Gas saturation (%)(Sg)						
11. Oil Saturation (%) So)						
12. Gas generation mgHC/g TOC (Hydrogen index)	100	400	**300**	triangular	***2***	Average estimated
13. Kerogen type	I/II	II/III	**II-II/III**		***2***	trace type III and I
14. Sorption capacity VReq. - 1,9 % (mmol/g)						
15. Matrix permeability (nDarcy)						
16. Adsorbed gas storage capacity (scf/ton)						
17. Compressibility factor (z)						
18a. Bg - Gas formation volume factor						
18b. Bo - Oil formation volume factor						
19. Langmuir Pressure (pL, psi)						
20. Langmuir Volume (nL, scf/ton)						
21. Bulk mineral constituents XRD						
21a Total Clay content (%)						
Content of smectite						
Content of Illite & Mica						
Content of Kaolinite						
21b Quartz-feldspars content (%)						
21c C arbonate content (%)						
22. Brittleness indicators						
22a Poisson's ratio						
22b Young's modulus						
22c other indicators						

REFERENCE LIST :

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2. Millenium Atlas

GARAH Capasity Parameters					Source (Ref.list)	Comments	3006
Shale Name:	Sleen Fm.				1	Netherland nomenclature	
Country:	Germany						
Age (Age):	Rhaetian						
Age (Epoch):	Upper Triassic						
Basin:	North Sea						
Chance of success parameters					**Source (Ref.list)**	**Comments**	
Mapping status	Poor				1		
Sedimentary variability	Moderate						
Structural complexity	Moderate						
Available HC data	Moderate				2	onshore - Analog Mittelrhät	
Proven source rock	Unknown				4	onshore possible	
Maturity variability	Moderate						
Depth	Average						
Mineral composition							
Detailed parameter list	**Min**	**Max**	**Mean**	**Distribution**	**Source (Ref.list)**	**Comments**	
1. Area (km2)						If possible provide distribution map	
Entenschnabel AU	0	1600	800	Normal	3	Jashar GIS	
2. Thickness (gross, m)	5	30	20	Normal		If possible provide thickness map	
2a. Thickness (net, m)							
2b. Net/Gross (%)							
3. Depth (m)	2200	5700	3600	Triangular		If possible provide depth map	
4. Density (g/cm3)	2,4	2,6	2,5	Normal	*2 + 3*		
5. TOC (%)	1,3	17,4	4	Normal	*2*	If possible provide map	
6. Porosity (%)			10,5	Normal	*2*		
7. Maturity (%VR) or graptolite equivalent	0,6	2,5	1,2	Normal	*3*	If possible provide map	
8. Reservoir pressure (psi)							
9. Reservoir Temperature (°C)							
10. Gas saturation (%)(Sg)							
11. Oil Saturation (%) So)							
12. Gas generation mgHC/g TOC (Hydrogen index)	40	280	160	Normal	*1*		
13. Kerogen type			II		*4+5*		
14. Sorption capacity VReq. - 1,9 % (mmol/g)							
15. Matrix permeability (nDarcy)							
16. Adsorbed gas storage capacity (scf/ton)							
17. Compressibility factor (z)							
18a. Bg - Gas formation volume factor							
18b. Bo - Oil formation volume factor							
19. Langmuir Pressure (pL, psi)			914			6.3 Mpa	
20. Langmuir Volume (nL, scf/ton)						4.0 m³/t	
21. Bulk mineral constituents XRD							
21a Total Clay content (%)							
Content of smectite							
Content of Illite & Mica							
Content of Kaolinite							
21b Quartz-feldspars content (%)							
*21c C*arbonate content (%)							

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3 3D BPSM

4 Boigk, H. 1981. Erdöl und Erdölgas in der Bundesrepublik Deutschland : Erdölprovinzen, Felder, Förderung, Vorräte, Lagerstättentechnik. (Enke, 1981), 330p.

5 SPBA

GARAH Capasity Parameters		Source (Ref.list)	Comments	3007
Shale Name:	Posidonia shale			
Country:	Germany			
Age (Age):	Toarcian			
Age (Epoch):	Lower Jurassic			
Basin:	North Sea			

Chance of success parameters		Source (Ref.list)	Comments
Mapping status	Moderate	1	
Sedimentary variability	Moderate		
Structural complexity	Moderate		
Available HC data	Moderate		not in Entenschnabel;
Proven source rock	Proven		
Maturity variability	Moderate		
Depth	Average		
Mineral composition	Poor		based on analogue onshore data

Detailed parameter list	Min	Max	Mean	Distribution	Source (Ref.list)	Comments
1. Area (km2)						
Mittelplate AU	810	900	860	Triangular		distribution map see SPBA; min/max +/- 10% of mean assumed
Entenschnabel AU	40	830	200	Triangular	*3D BPSM*	distribution map provided
2. Thickness (gross, m)	20	50	35	Normal	*2*	thickness map not available
2a. Thickness (net, m)	20	50	35	Normal	*assumed*	
2b. Net/Gross (%)	100	100	100	Uniform	*assumed*	
3. Depth (m)						
Mittelplate AU	1000	4500	2000	Normal	*2*	no depth map
Entenschnabel AU	2200	5000	3500	Normal	*3D BPSM*	depth map provided
4. Density (g/cm3)	2,2	2,6	2,4		*3D BPSM*	
5. TOC (%)	1	16	4,3	Normal	*2*	If possible provide map
6. Porosity (%)	6	22	11	Normal	*3D BPSM*	skewed normal distribution
7. Maturity (%VR) or graptolite equivalent	0,6	2,3	1,1	Normal	*3D BPSM*	If possible provide map
8. Reservoir pressure (psi)	./.	./.	./.			
9. Reservoir Temperature (°C)						
Entenschnabel AU	100	200	150	Uniform	*3D BPSM*	
10. Gas saturation (%)(Sg)						
11. Oil Saturation (%) So)						
12. Gas generation mgHC/g TOC (Hydrogen index)	125	600	250	Normal		skewed normal
13. Kerogen type			I-II			
14. Sorption capacity VReq. - 1,9 % (mmol/g)						
15. Matrix permeability (nDarcy)						
16. Adsorbed gas storage capacity (scf/ton)						
17. Compressibility factor (z)						
18a. Bg - Gas formation volume factor						
18b. Bo - Oil formation volume factor						
19. Langmuir Pressure (pL, psi)			1.290		2	8.9 in Mpa
20. Langmuir Volume (nL, scf/ton)					2	4,8 m³/t
21. Bulk mineral constituents XRD						
21a Total Clay content (%)	30	80	50	Normal	*2*	
Content of smectite						
Content of Illite & Mica						
Content of Kaolinite						
21b Quartz-feldspars content (%)	10	40	20	Normal	*2*	
*21c C*arbonate content (%)	0	60	30	Normal	*2*	

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GARAH Capasity Parameters		Source (Ref.list)	Comments
Shale Name:	Hot shale	1, 2	Bo Member, Clay deep
Country:	Germany		
Age (Age):	Tithonian		to Berriasian
Age (Epoch):	Upper Jurassic		to Lower Cretacious
Basin:	North Sea		Entenschnabel

3008

Chance of success parameters		Source (Ref.list)	Comments
Mapping status	Moderate		
Sedimentary variability	Moderate		
Structural complexity	Moderate		
Available HC data	Moderate		
Proven source rock	Possible		
Maturity variability	Moderate		
Depth	Average		
Mineral composition	No data		

Detailed parameter list	Min	Max	Mean	Distribution	Source (Ref.list)	Comments
1. Area (km2)	860	3500	1000	Normal		If possible provide distribution map
Entenschnabel AU					*2*	GIS shape provided
2. Thickness (gross, m)	5	80	**25**	Normal		
2a. Thickness (net, m)	5	30	**15**	Normal		
2b. Net/Gross (%)						
3. Depth (m)	1500	4000	**2800**	Normal		
4. Density (g/cm3)	2,3	2,5	**2,4**	Normal	***3D BSM***	
5. TOC (%)	3	8,4	**5**	Normal		
6. Porosity (%)						
7. Maturity (%VR) or graptolite equivalent	0,4	1,2	**0,6**	Normal		
8. Reservoir pressure (psi)						
9. Reservoir Temperature (°C)	80	160	**100**	Normal		
10. Gas saturation (%)(Sg)						
11. Oil Saturation (%) So)						
12. Gas generation mgHC/g TOC (Hydrogen index)	400	600	**500**	Normal		
13. Kerogen type			**I-II**			
14. Sorption capacity VReq. - 1,9 % (mmol/g)						
15. Matrix permeability (nDarcy)						
16. Adsorbed gas storage capacity (scf/ton)						
17. Compressibility factor (z)						
18a. Bg - Gas formation volume factor						
18b. Bo - Oil formation volume factor						
19. Langmuir Pressure (pL, psi)						
20. Langmuir Volume (nL, scf/ton)						
21. Bulk mineral constituents XRD						
21a Total Clay content (%)						
Content of smectite						
Content of Illite & Mica						
Content of Kaolinite						
21b Quartz-feldspars content (%)						
21c Carbonate content (%)						

REFERENCE LIST :

1 Ineson, J.R., Bojesen-Koefoed, J.A., Dybkjar, K., Nielsen, L.H., 2003. Volgian–Ryazanian 'hot shales' of the Bo Member (Farsund Formation) in the Danish Central Graben, North Sea: stratigraphy, facies and geochemistry. Geological Survey of Denmark and Greenland Bulletin, 1, 403–436.

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3. SPBA

GARAH Capasity Parameters		Source (Ref.list)	Comments
Shale Name:	Geverik Member		
Country:	Netherlands		
Age (Age):	Serpukovian		
Age (Epoch):	Mississippian		
Basin:	North Sea		

3009

Chance of success parameters		Source (Ref.list)	Comments
Mapping status	Moderate		
Sedimentary variability	Moderate		
Structural complexity	Moderate		
Available HC data	Moderate		
Proven source rock	Unknown		
Maturity variability	High		see maturity map
Depth	Deep		see depth map
Mineral composition	Favourable	3	

Detailed parameter list	Min	Max	Mean	Distribution	Source (Ref.list)	Comments
1. Area (km2)			59050	Normal		see depth map
2. Thickness (gross, m)						If possible provide thickness map
2a. Thickness (net, m)	40	80	**50**	Normal	**6**	
2b. Net/Gross (%)			**70**			
3. Depth (m)	29	9935	**5658**	Normal		see depth map
4. Density (g/cm3)	2,63	2,77	**2,71**	Normal	**3**	
5. TOC (%)	1	9	**2**	Normal	**1,2,4**	If possible provide map
6. Porosity (%)	1	9	**1,5**	Normal	**1,2**	
7. Maturity (%VR) or graptolite equivalent	0,6	4,7	**3,3**	Normal		see map
8. Reservoir pressure (psi)	7	106	**63**	Normal	**14**	Mpa based on trend from measured data in overlying formation, calculated for respective formation depth
9. Reservoir Temperature (°C)				Normal	**13**	average geothermal gradient of 31,3 C/km onshore
10. Gas saturation (%)(Sg)	20	50	**20**	Normal	**1,2**	
11. Oil Saturation (%) So)						
12. Gas generation mgHC/g TOC (Hydrogen index)						
13. Kerogen type			**Type II**		**1,4**	
14. Sorption capacity VReq. - 1,9 % (mmol/g)						
15. Matrix permeability (nDarcy)	0,9	680			**2**	
16. Adsorbed gas storage capacity (scf/ton)			**33**		**2**	
17. Compressibility factor (z)						
18a. Bg - Gas formation volume factor			**212**		1	
18b. Bo - Oil formation volume factor						
19. Langmuir Pressure (pL, psi)						
20. Langmuir Volume (nL, scf/ton)						
21. Bulk mineral constituents XRD						
21a Total Clay content (%)			**5**		3	
Content of smectite						
Content of Illite & Mica						
Content of Kaolinite						
21b Quartz-feldspars content (%)			**69**		3	
21c Carbonate content (%)			**26**		3	

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GARAH Capasity Parameters		Source (Ref.list)	Comments
Shale Name:	Posidonia Shale Formation		
Country:	Netherlands		
Age (Age):	Toarcian		
Age (Epoch):	Lower Jurassic		
Basin:	North Sea		

3010

Chance of success parameters		Source (Ref.list)	Comments
Mapping status	Good		
Sedimentary variability	Low		
Structural complexity	Moderate		
Available HC data	Good		
Proven source rock	Proven		
Maturity variability	Moderate		
Depth	Average		
Mineral composition	Poor		

Detailed parameter list	Min	Max	Mean	Distribution	Source (Ref.list)	Comments
1. Area (km2)			6240	Normal	***15***	see depth map
2. Thickness (gross, m)						If possible provide thickness map
2a. Thickness (net, m)	26	58	**41**	Normal	***15***	see thickness map
2b. Net/Gross (%)			**90**			
3. Depth (m)	516	7058	**3124**	Normal	***15***	see depth map
4. Density (g/cm3)						
5. TOC (%)	2	18	**5,7**	Normal	***1,2,15***	If possible provide map
6. Porosity (%)	5	13	**7**	Normal	***1,2,7***	
7. Maturity (%VR) or graptolite equivalent	0	2,5	**0,8**	Normal		see map
8. Reservoir pressure (psi)	9,79	46,32	**26,6**	Normal	***14***	Mpa - based on reservoir pressure measurements in a directly overlying reservoir
9. Reservoir Temperature (°C)				Normal	***13***	average geothermal gradient of 31,3 C/km onshore
10. Gas saturation (%)(Sg)	0	50	**23**		***1,2***	
11. Oil Saturation (%) So)						
12. Gas generation mgHC/g TOC (Hydrogen index)						
13. Kerogen type			**Type II**		***1,7,8***	
14. Sorption capacity VReq. - 1,9 % (mmol/g)						
15. Matrix permeability (nDarcy)	190	16000			***2***	
16. Adsorbed gas storage capacity (scf/ton)			**81**		***2***	
17. Compressibility factor (z)						
18a. Bg - Gas formation volume factor			**195**		**1**	
18b. Bo - Oil formation volume factor						
19. Langmuir Pressure (pL, psi)						
20. Langmuir Volume (nL, scf/ton)						
21. Bulk mineral constituents XRD						
21a Total Clay content (%)	40	70			**16**	
Content of smectite	0	10			**16**	
Content of Illite & Mica	5	10			**16**	
Content of Kaolinite	10	20			**16**	
21b Quartz-feldspars content (%)	10	20			**16**	
21c C arbonate content (%)	2	20			**16**	

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GARAH Capasity Parameters	Min	Max	Mean	Distribution	Source (Ref.list)	Comments
Shale Name: Bowland -Hodder unit						3011
Age: Carboniferous						
Basin: Northern England						
Structural setting: Complex						
Facies variability:						
Country: UK						
1. Gas mature area (km2)	5087	10540	7814	Normal	5	Area of basinal shales, (Cleveland D, E, UBS) within gas mature region
Offshore AU						
Onshore AU						
2. Thickness (gross, m)	17	110	38,5		2	Upper Bowland Shale thickness from 6 wells
2a. Thickness (net, m)	13,7	81,8	58,1		2	Upper Bowland Shale net shale thickness from 6 wells
2b. Net/Gross (%)						
2c. Net mature shale volume (x 10^9 m^3)						
3. Depth (m)	2121	4876	3207		6	Measured depth from 9 well penetrations
4. Density (g/cm3)	2,55	2,65	2,6		1	estimated
5. TOC (%)	1,47	4,62	3,23		2	Measered in wells
6. Porosity (%)	0,05	0,11	0,07		4	From 43/21- 2.
7. Maturity (%VR) or graptolite equivalent						
7.b Maturity Tmax	312	545	420		3	Analysed, four legacy wells (Upper Bowland Shale)
8. Reservoir pressure (psi)	18	27	22,5		1	
9. Reservoir Temperature (°C)						Variable- depth dependant
10. Gas saturation (%)(Sg)	0,5	10	3		1	estimated gas filled porosity
11. Oil Saturation (%) So)						
12. Gas generation mgHC/g TOC (Hydrogen index)	2	350	34,7		2	Measured in 4 wells
13. Kerogen type			II, III		3	analysed
14. Sorption capacity VReq. - 1,9 % (mmol/g)						not known
15. Matrix permeability (nDarcy)	0,03	0,15	0,05		4	From 43/21- 2 (petrophysics)
16. Adsorbed gas storage capacity (scf/ton)	18	71	44,5		1	
17. Compressibility factor (z)						not known
18. Bg - Gas formation volume factor	168	253	210,5		1	estimated
19. Langmuir Pressure (pL, psi)	2,5	10	6,25		1	estimated
20. Langmuir Volume (nL, scf/ton)	18	71	44,5		1	Analogues used from US (Curtis 2002; Jarvie 2012a)

Bulk mineral constituents XRD	%	Source	Mineralogy
Average clay content (%)			
Average quartz-feldspars content (%)			
Average carbonate content (%)			

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GARAH Capasity Parameters		Source (Ref.list)	Comments
Shale Name:	Lias Gp Posidonia Equivalent		Jet Rock Mb (Cleveland Basin) Cerdic Fm (Offshore SNS)
Country:	UK		
Age (Age):	Toarcian		
Age (Epoch):	Lower Jurassic		
Basin:	Cleveland Basin, Southern North Sea		

Chance of success parameters		Source (Ref.list)	Comments
Mapping status	Moderate		
Sedimentary variability	Moderate		
Structural complexity	Moderate		
Available HC data	Moderate		
Proven source rock	Possible		
Maturity variability	Moderate		
Depth	Average		
Mineral composition	No data		

Detailed parameter list	Min	Max	Mean	Distribution	Source (Ref.list)	Comments
1. Oil mature area (km2)	1412	2009	1710	Normal	2, 3	From GIS analysis, depth and maturity cut-offs applied
2. Thickness (Toarcian, gross, m)	24	57	**43,2**		*1*	Thickness of Toarcian/Cerdic Fm
2a. Thickness (net, m)						Jet Rock Mb only 7.2m thick
2b. Net/Gross (%)						
3. Depth (m)	1000	1871	**1171**			Depth to Upper Jurassic. Depth and maturity cut-offs applied. From GIS raster histogram.
4. Density (g/cm3)						
5. TOC (%)	2	12,4	**8,08**		*1*	StDev = 2.32
6. Porosity (%)						
7. Maturity (%VR) or graptolite equivalent					*1*	Tmax 425-440 - Early Oil Mature (HypoLias) IGI DB shows 0.5-1.2 (undiff Lias Gp)
8. Reservoir pressure (psi)						no data
9. Reservoir Temperature (°C)						no data
10. Gas saturation (%)(Sg)						no data
11. Oil Saturation (%) So)						no data
12. Gas generation mgHC/g TOC (Hydrogen index)	0	668			*1*	Min-max estimated from published charts
13. Kerogen type			**Type II**		*1*	
14. Sorption capacity VReq. - 1,9 % (mmol/g)						no data
15. Matrix permeability (nDarcy)						no data
16. Adsorbed gas storage capacity (scf/ton)						no data
17. Compressibility factor (z)						no data
18a. Bg - Gas formation volume factor						no data
18b. Bo - Oil formation volume factor						no data
19. Langmuir Pressure (pL, psi)						no data
20. Langmuir Volume (nL, scf/ton)						no data
21. Bulk mineral constituents XRD						
21a Total Clay content (%)						no data
Content of smectite						no data
Content of Illite & Mica						no data
Content of Kaolinite						no data
21b Quartz-feldspars content (%)						no data
*21c C*arbonate content (%)						no data

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GARAH Capasity Parameters					Source (Ref.list)	Comments
Shale Name:	Kimmeridge clay					
Country:	UK					
Age (Age):						
Age (Epoch):	Upper Jurassic					
Basin:	North Sea					
Chance of success parameters					**Source (Ref.list)**	**Comments**
Mapping status	Good					
Sedimentary variability	Moderate					
Structural complexity	Moderate					
Available HC data	Good					
Proven source rock	Proven					
Maturity variability	Moderate					
Depth	Average					
Mineral composition	Poor					Favourable in areas with high clastic input (e.g. UK Quadrant 16)
Detailed parameter list	**Min**	**Max**	**Mean**	**Distribution**	**Source (Ref.list)**	**Comments**
1. Oil mature area (km2)	9710	13815	**11763**	Normal	**6,7**	From GIS polygons. Depth and maturity cut-offs applied.
Gas mature area (km2)	577	821	**699**	Normal	**6,7**	
2. Thickness (gross, m)	0,9	1123	**126**			From well penetrations (oil mature area only)
2a. Thickness (net, m)						
2b. Net/Gross (%)						
3. Depth (m)	22,1	6572	1757		6	From GIS raster
4. Density (g/cm3)	2,55	2,65	2,6		1	estimated
4b. Oil density (g/cm3)	0,8	0,85	0,825		1	analysed
5. TOC (%)	0	12	4,56		4	From samples in the IGI Database. (A small number of samples have TOCs up to 78%).
6. Porosity (%)		15			3	Up to 15%
7. Maturity (%VR) or graptolite equivalent					6	From GIS VR map
8. Reservoir pressure (psi)					4	Avg gradient 0.45psi/ft
9. Reservoir Temperature (°C)						Variable- depth dependant
10. Gas saturation (%)(Sg)						no data
11. Oil Saturation (%) So)						no data
12. Gas generation mgHC/g TOC (Hydrogen index)	0	12825	277,5		4	Min-mean-max from Kimmerige Clay samples in IGI database
13. Kerogen type			Type II		2	
14. Sorption capacity VReq. - 1,9 % (mmol/g)						no data
15. Matrix permeability (nDarcy)						no data
16. Adsorbed gas storage capacity (scf/ton)						no data
17. Compressibility factor (z)						no data
18a. Bg - Gas formation volume factor						no data
18b. Bo - Oil formation volume factor						no data
19. Langmuir Pressure (pL, psi)						no data
20. Langmuir Volume (nL, scf/ton)						no data
21. Bulk mineral constituents XRD						
21a Total Clay content (%)	20	50			4	Approximate range
Content of smectite						no data
Content of Illite & Mica						no data
Content of Kaolinite						no data
21b Quartz-feldspars content (%)	25	40			8	Approximate range
21c C arbonate content (%)		80	23		3	Up to 80%

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9 APPENDIX B. EXTENDED LITERATURE LIST

Literature list for defining Screening Capacity parameters (CP) in the North Sea Basin shale resources plays:

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Zijp, M.H.A.A., ten Veen J., Verreussel, R., ter Heege, J., Ventra, D., Martin, J. 2015. Shale gas formation research: from well logs to outcrop - and back again. First Break Volume 33, February 2015.

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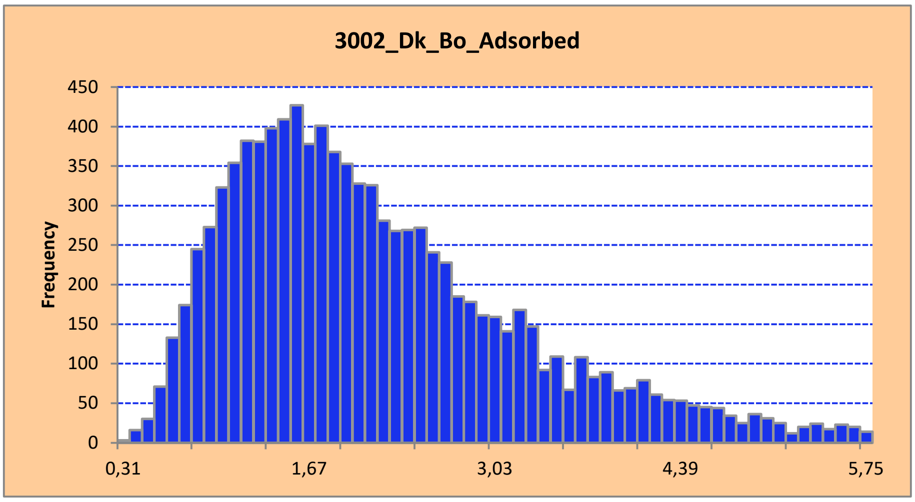
10 APPENDIX C. MONTE CARLO SIMULATION RESULTS

Forecasts

Forecast: 3002_Dk_Bo_Adsorbed

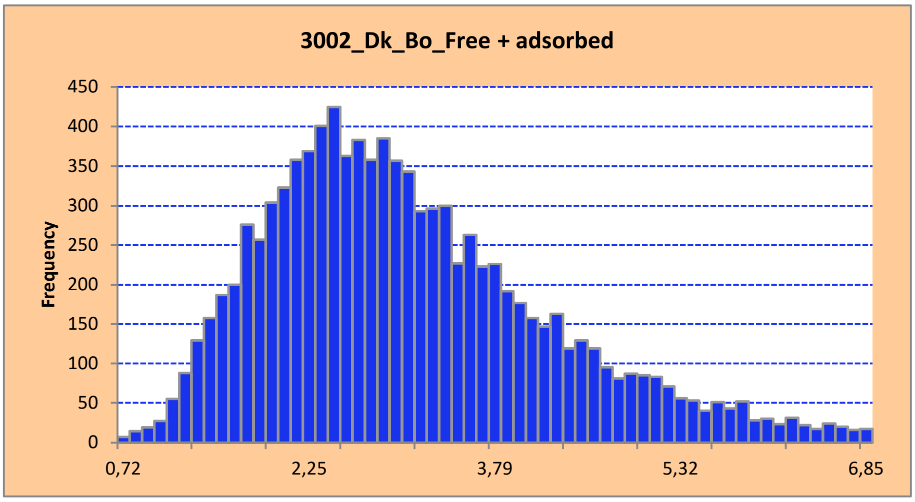
Summary:
Entire range is from 0,26 to 17,86
Base case is 0,03
After 10.000 trials, the std. error of the mean is 0,01



Statistics:	Forecast values
Trials	10.000
Base Case	0,03
Mean	2,25
Median	1,95
Mode	---
Standard Deviation	1,27
Variance	1,60
Skewness	1,95
Kurtosis	11,18
Coeff. of Variation	0,5623
Minimum	0,26
Maximum	17,86
Range Width	17,60
Mean Std. Error	0,01

Forecast: 3002_Dk_Bo_Free + adsorbed

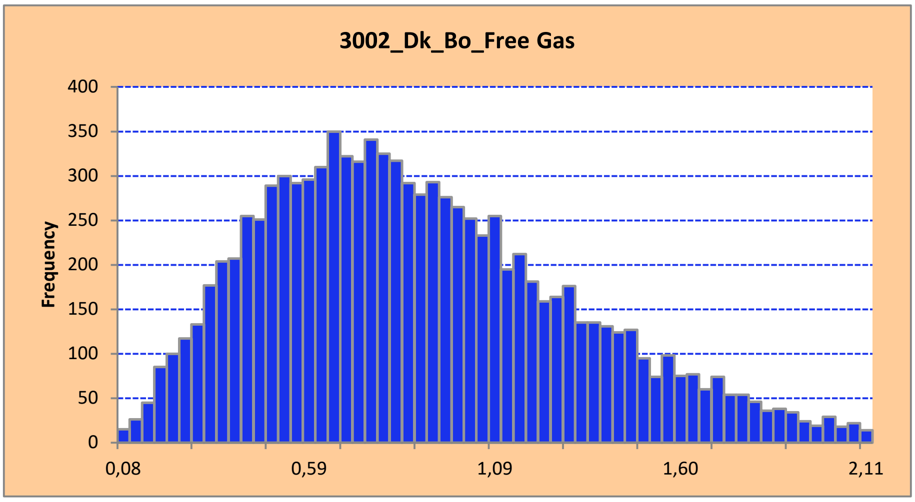
Summary:
Entire range is from 0,67 to 19,30
Base case is 374,65
After 10.000 trials, the std. error of the mean is 0,01



Statistics:	Forecast values
Trials	10.000
Base Case	374,65
Mean	3,15
Median	2,90
Mode	---
Standard Deviation	1,34
Variance	1,80
Skewness	1,64
Kurtosis	9,59
Coeff. of Variation	0,4259
Minimum	0,67
Maximum	19,30
Range Width	18,63
Mean Std. Error	0,01

Forecast: 3002_Dk_Bo_Free Gas

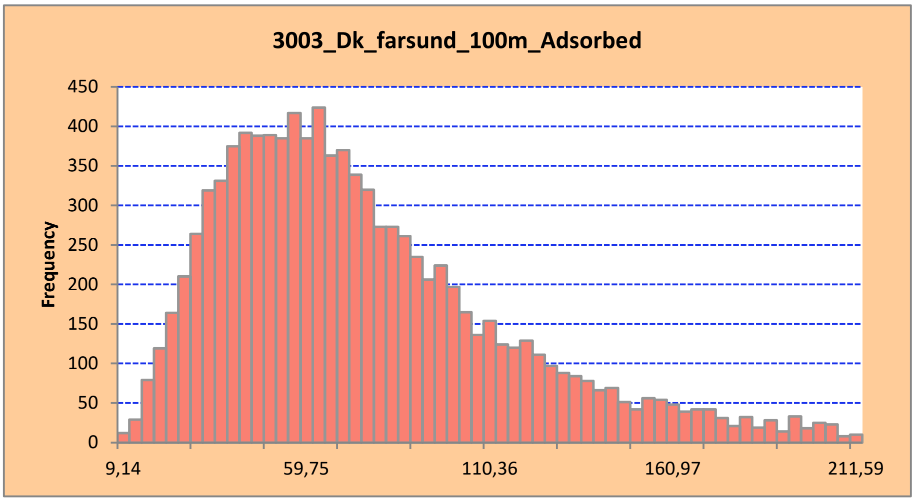
Summary:
Entire range is from 0,07 to 3,12
Base case is 374,61
After 10.000 trials, the std. error of the mean is 0,00



Statistics:	Forecast values
Trials	10.000
Base Case	374,61
Mean	0,90
Median	0,83
Mode	---
Standard Deviation	0,44
Variance	0,19
Skewness	0,7549
Kurtosis	3,53
Coeff. of Variation	0,4871
Minimum	0,07
Maximum	3,12
Range Width	3,06
Mean Std. Error	0,00

Forecast: 3003_Dk_farsund_100m_Adsorbed

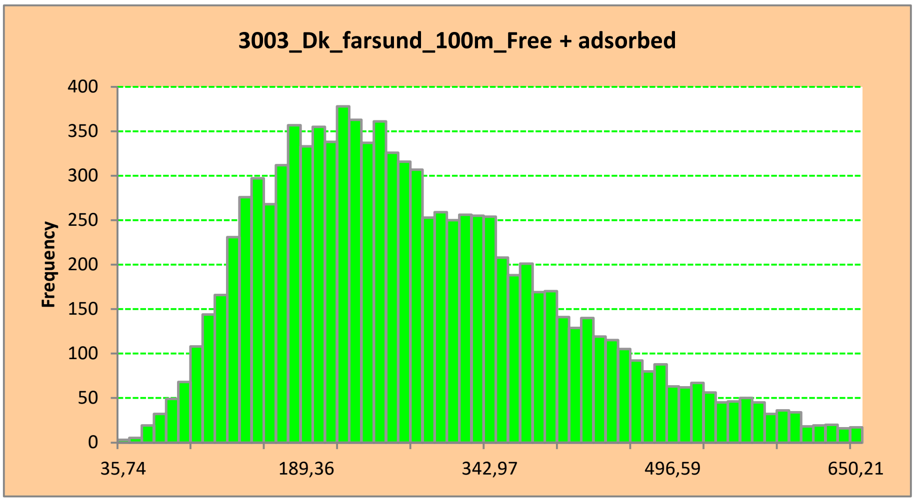
Summary:
Certainty level is 0,00%
Certainty range is from ∞ to ∞
Entire range is from 7,45 to 539,94
Base case is 0,03
After 10.000 trials, the std. error of the mean is 0,48



Statistics:	Forecast values
Trials	10.000
Base Case	0,03
Mean	78,84
Median	67,70
Mode	---
Standard Deviation	48,01
Variance	2.305,24
Skewness	2,02
Kurtosis	10,59
Coeff. of Variation	0,6090
Minimum	7,45
Maximum	539,94
Range Width	532,49
Mean Std. Error	0,48

Forecast: 3003_Dk_farsund_100m_Free + adsorbed

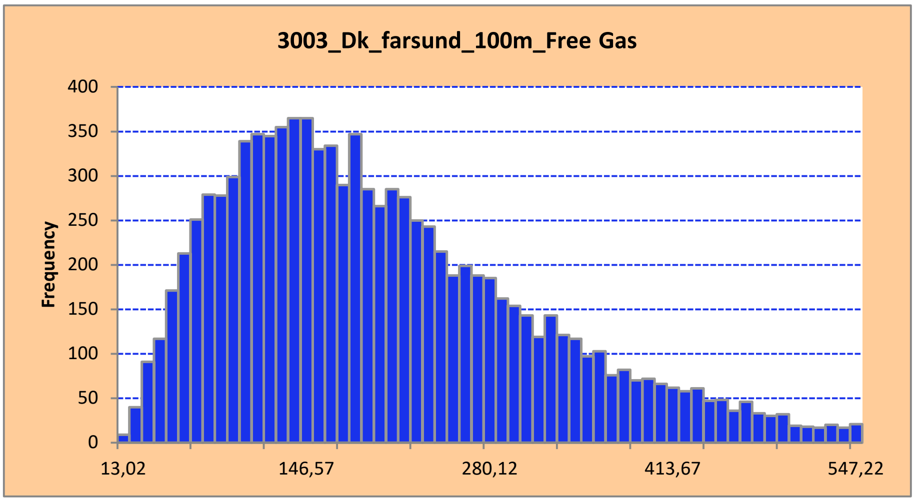
Summary:
Entire range is from 30,62 to 993,46
Base case is 374,65
After 10.000 trials, the std. error of the mean is 1,32



Statistics:	Forecast values
Trials	10.000
Base Case	374,65
Mean	286,58
Median	262,18
Mode	---
Standard Deviation	131,70
Variance	17.343,95
Skewness	0,9877
Kurtosis	4,16
Coeff. of Variation	0,4595
Minimum	30,62
Maximum	993,46
Range Width	962,84
Mean Std. Error	1,32

Forecast: 3003_Dk_farsund_100m_Free Gas

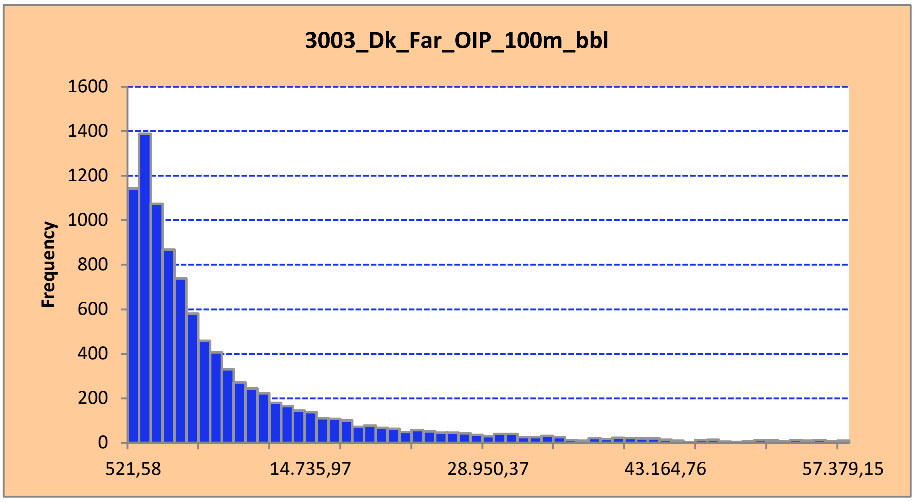
Summary:
Entire range is from 8,57 to 944,09
Base case is 374,61
After 10.000 trials, the std. error of the mean is 1,23



Statistics:	Forecast values
Trials	10.000
Base Case	374,61
Mean	207,74
Median	182,41
Mode	---
Standard Deviation	122,83
Variance	15.087,50
Skewness	1,15
Kurtosis	4,64
Coeff. of Variation	0,5913
Minimum	8,57
Maximum	944,09
Range Width	935,52
Mean Std. Error	1,23

Forecast: 3003_Dk_Far_OIP_100m_bbl

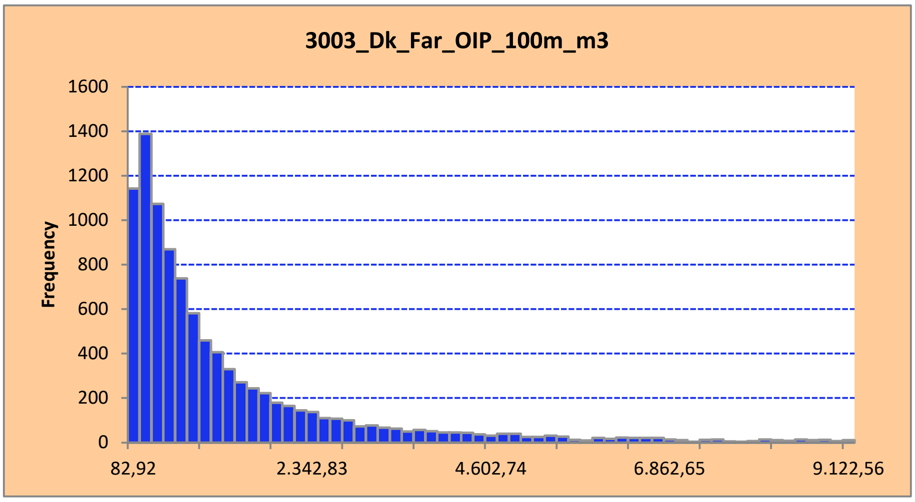
Summary:
Entire range is from 47,77 to 359.559,95
Base case is 11.832,77
After 10.000 trials, the std. error of the mean is 171,86



Statistics:	Forecast values
Trials	10.000
Base Case	11.832,77
Mean	9.733,50
Median	4.507,65
Mode	---
Standard Deviation	17.185,52
Variance	295.342.192,74
Skewness	7,12
Kurtosis	96,57
Coeff. of Variation	1,77
Minimum	47,77
Maximum	359.559,95
Range Width	359.512,18
Mean Std. Error	171,86

Forecast: 3003_Dk_Far_OIP_100m_m3

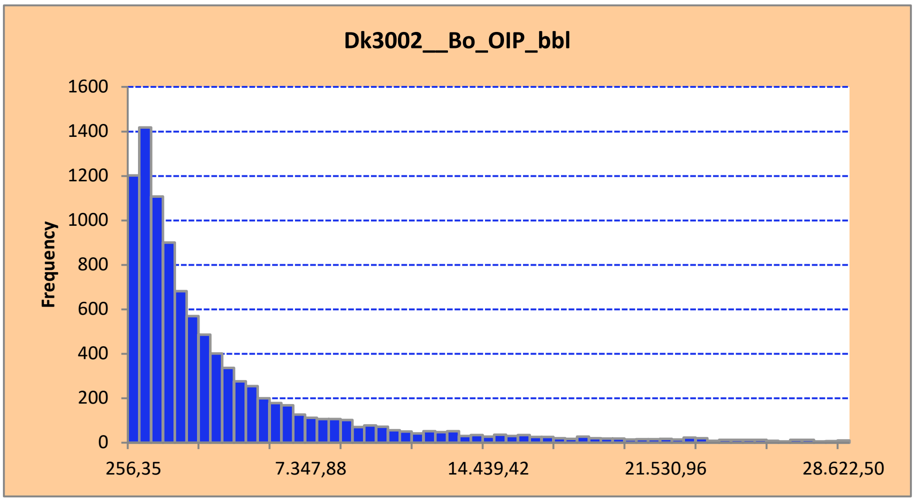
Summary:
Entire range is from 7,59 to 57.165,47
Base case is 1.881,26
After 10.000 trials, the std. error of the mean is 27,32



Statistics:	Forecast values
Trials	10.000
Base Case	1.881,26
Mean	1.547,50
Median	716,66
Mode	---
Standard Deviation	2.732,28
Variance	7.465.353,25
Skewness	7,12
Kurtosis	96,57
Coeff. of Variation	1,77
Minimum	7,59
Maximum	57.165,47
Range Width	57.157,87
Mean Std. Error	27,32

Forecast: Dk3002__Bo_OIP_bbl

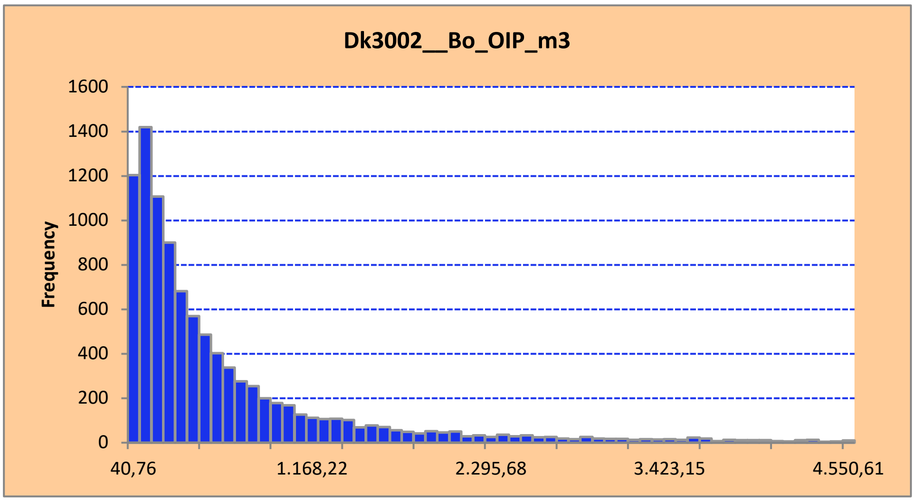
Summary:
Entire range is from 19,96 to 186.503,40
Base case is 1.227,62
After 10.000 trials, the std. error of the mean is 86,18



Statistics:	Forecast values
Trials	10.000
Base Case	1.227,62
Mean	4.728,39
Median	2.155,15
Mode	---
Standard Deviation	8.618,03
Variance	74.270.470,20
Skewness	6,96
Kurtosis	85,99
Coeff. of Variation	1,82
Minimum	19,96
Maximum	186.503,40
Range Width	186.483,44
Mean Std. Error	86,18

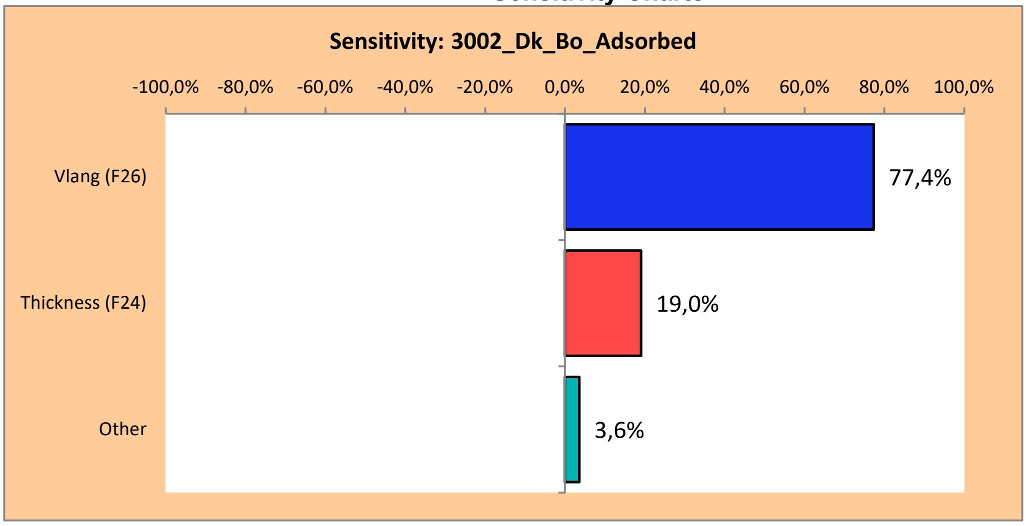
Forecast: Dk3002__Bo_OIP_m3

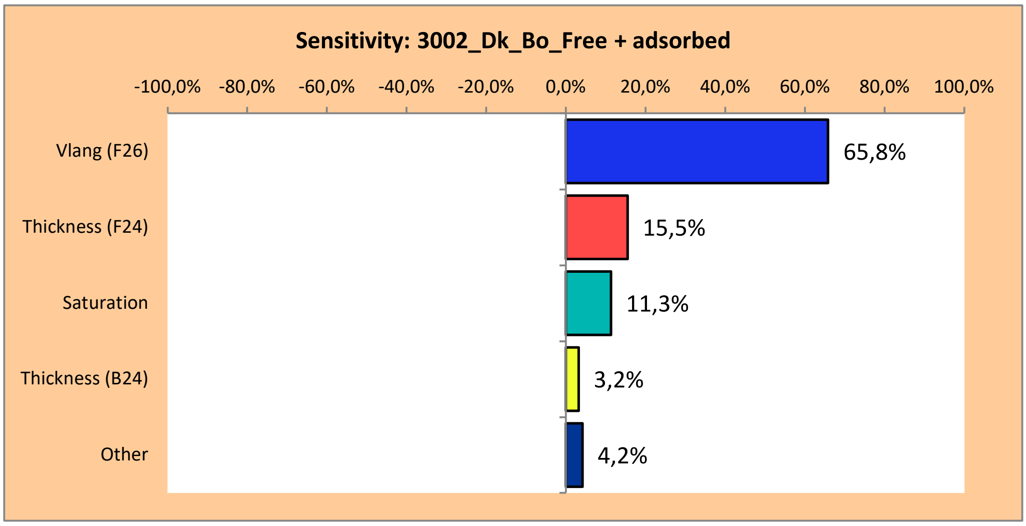
Summary:
Entire range is from 3,17 to 29.651,67
Base case is 195,18
After 10.000 trials, the std. error of the mean is 13,70

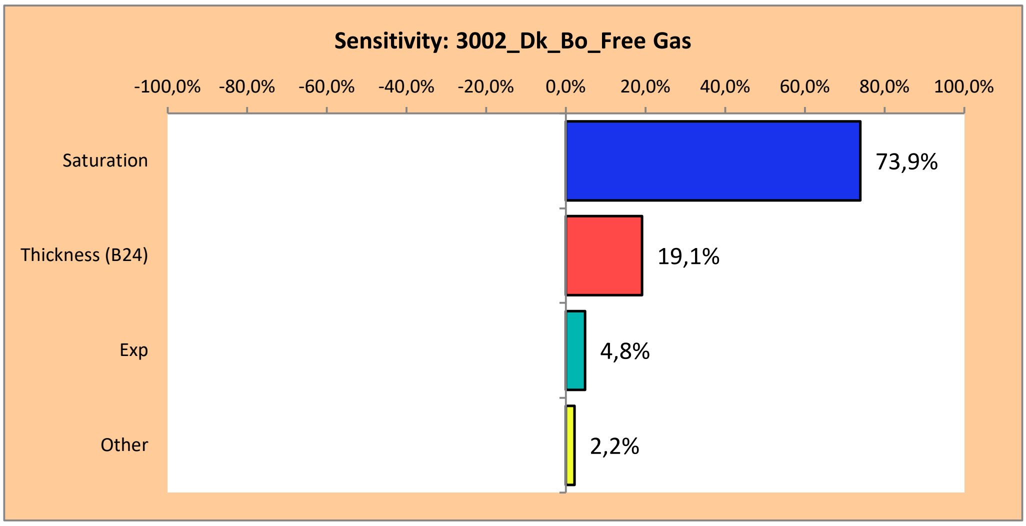


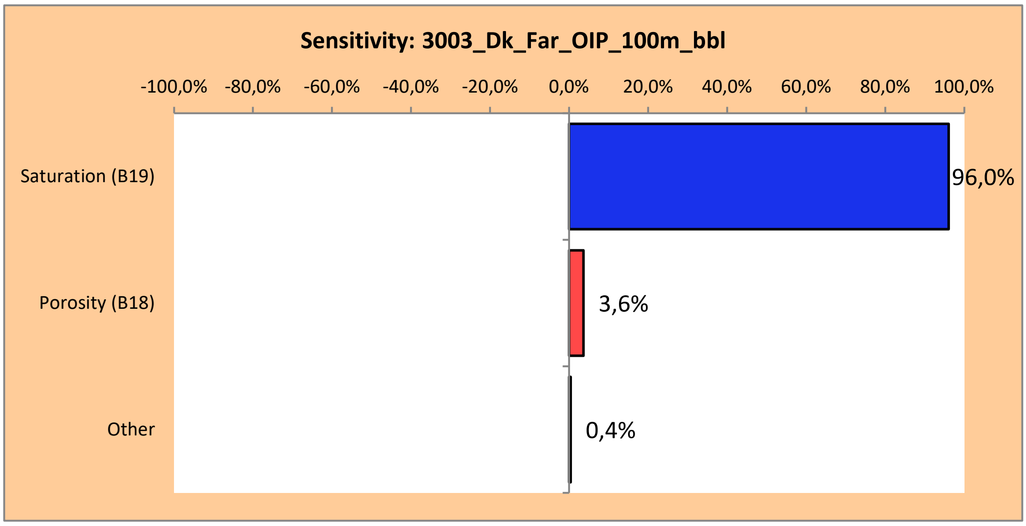
Statistics:	Forecast values
Trials	10.000
Base Case	195,18
Mean	751,75
Median	342,64
Mode	---
Standard Deviation	1.370,16
Variance	1.877.331,82
Skewness	6,96
Kurtosis	85,99
Coeff. of Variation	1,82
Minimum	3,17
Maximum	29.651,67
Range Width	29.648,50
Mean Std. Error	13,70

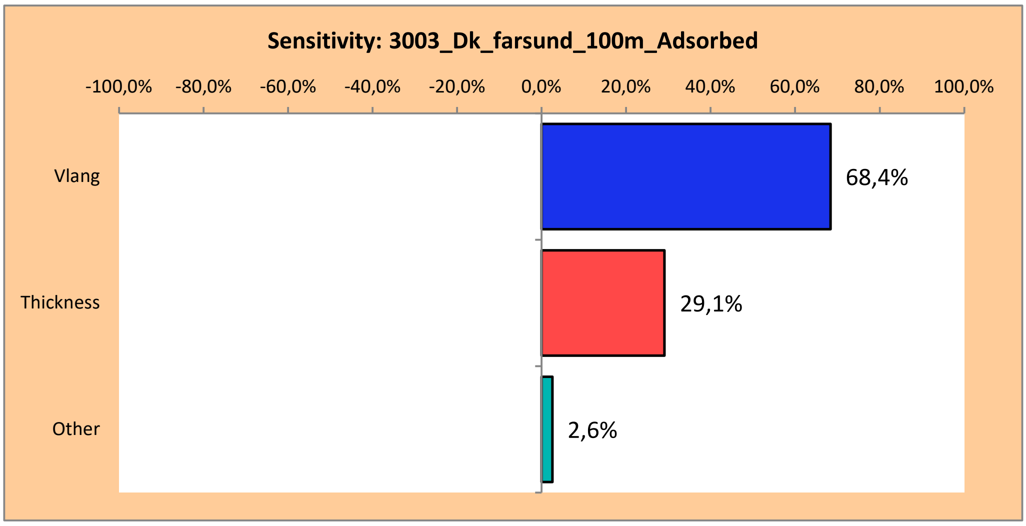
Sensitivity Charts

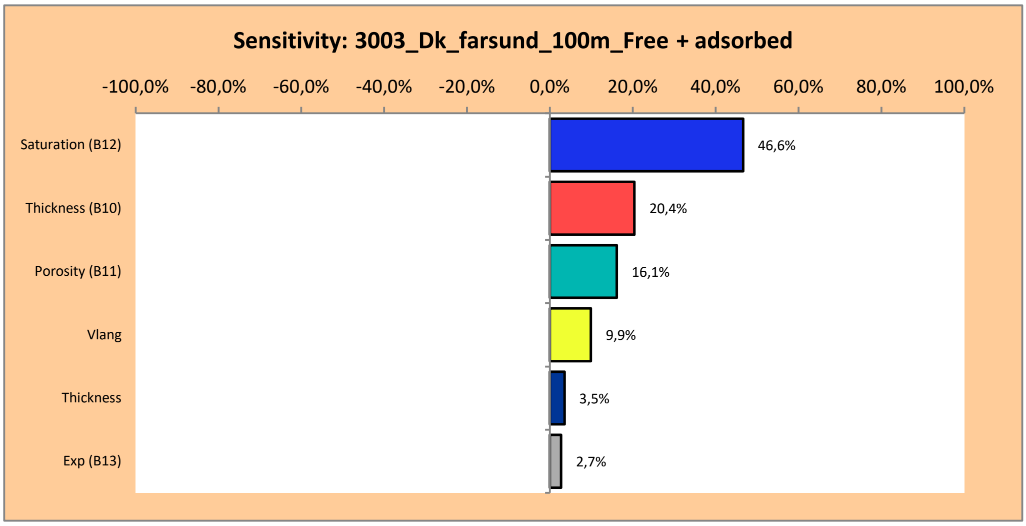


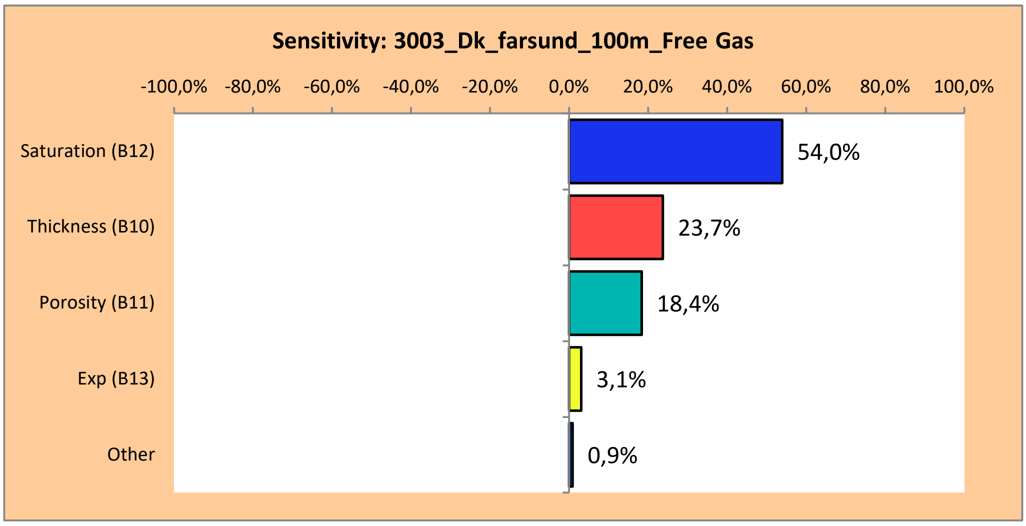


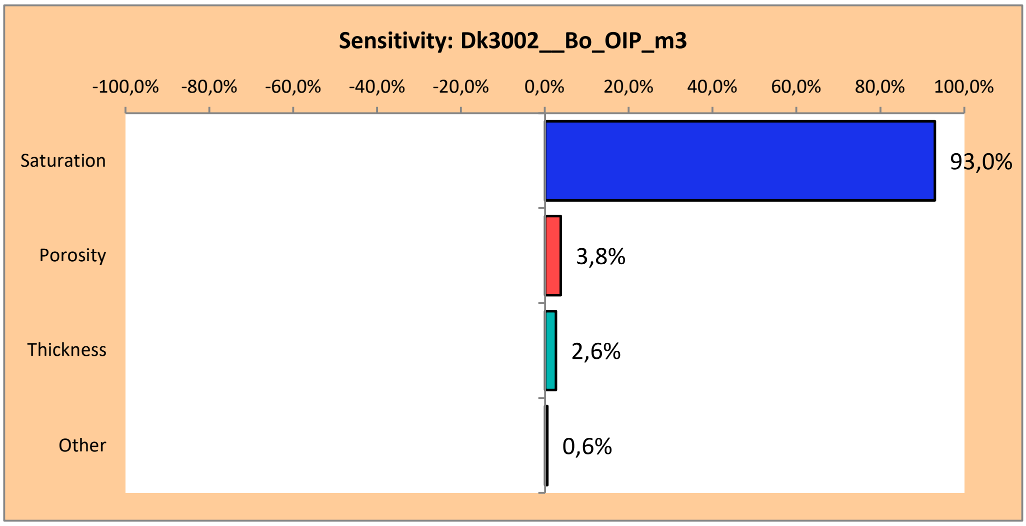

Sensitivity: 3002_Dk_Bo_Free Gas
-100,0%
-80,0%
-60,0%
-40,0%
-20,0%
0,0%
20,0%
40,0%
60,0%
80,0%
100,0%
Saturation
Thickness (B24)
Exp
Other
73,9%
19,1%
4,8%
2,2%


Sensitivity: 3003_Dk_Far_OIP_100m_bbl
-100,0%
-80,0%
-60,0%
-40,0%
-20,0%
0,0%
20,0%
40,0%
60,0%
80,0%
100,0%
Saturation (B19)
Porosity (B18)
Other
96,0%
3,6%
0,4%


Sensitivity: 3003_Dk_farsund_100m_Adsorbed
-100,0% -80,0% -60,0% -40,0% -20,0% 0,0% 20,0% 40,0% 60,0% 80,0% 100,0%
Vlang
68,4%
Thickness
29,1%
Other
2,6%


Sensitivity: 3003_Dk_farsund_100m_Free + adsorbed
-100,0% -80,0% -60,0% -40,0% -20,0% 0,0% 20,0% 40,0% 60,0% 80,0% 100,0%
Saturation (B12)
46,6%
Thickness (B10)
20,4%
Porosity (B11)
16,1%
Vlang
9,9%
Thickness
3,5%
Exp (B13)
2,7%



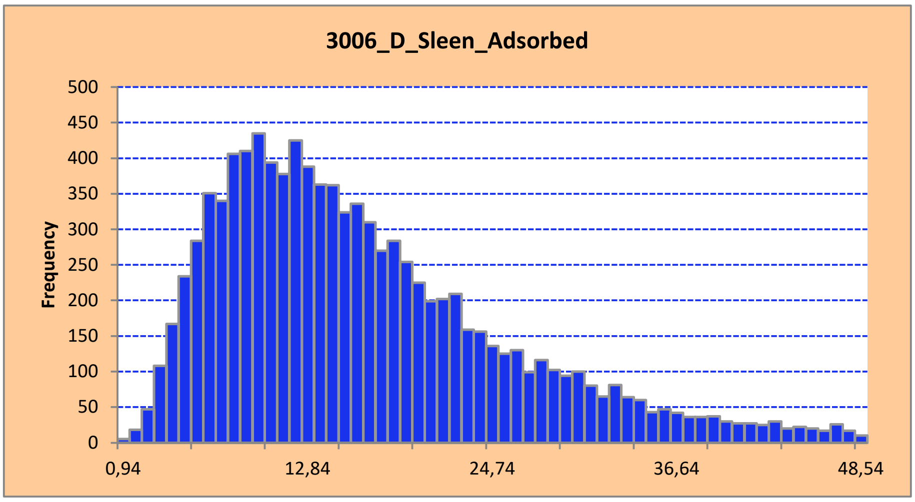


End of Sensitivity Charts

Forecasts

Forecast: 3006_D_Sleen_Adsorbed

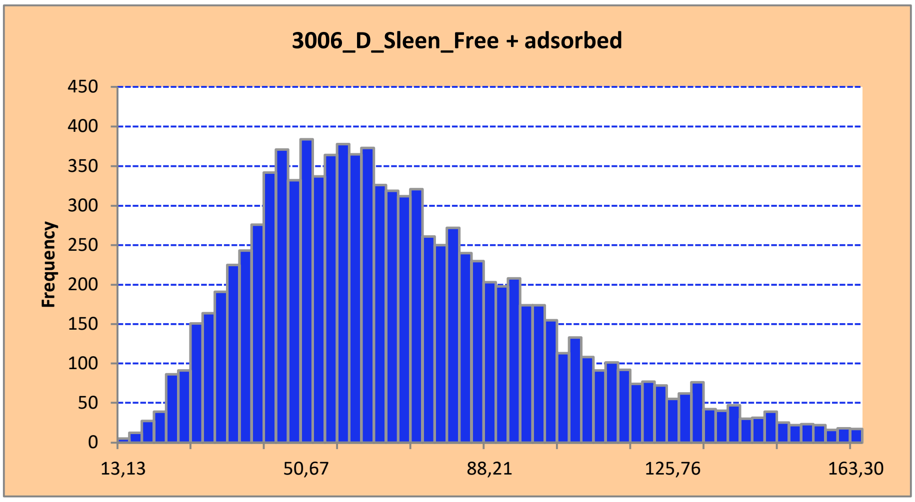
Summary:
Entire range is from 0,54 to 119,78
Base case is 0,03
After 10.000 trials, the std. error of the mean is 0,11



Statistics:	Forecast values
Trials	10.000
Base Case	0,03
Mean	17,27
Median	14,51
Mode	---
Standard Deviation	11,31
Variance	127,90
Skewness	2,06
Kurtosis	10,91
Coeff. of Variation	0,6549
Minimum	0,54
Maximum	119,78
Range Width	119,23
Mean Std. Error	0,11

Forecast: 3006_D_Sleen_Free + adsorbed

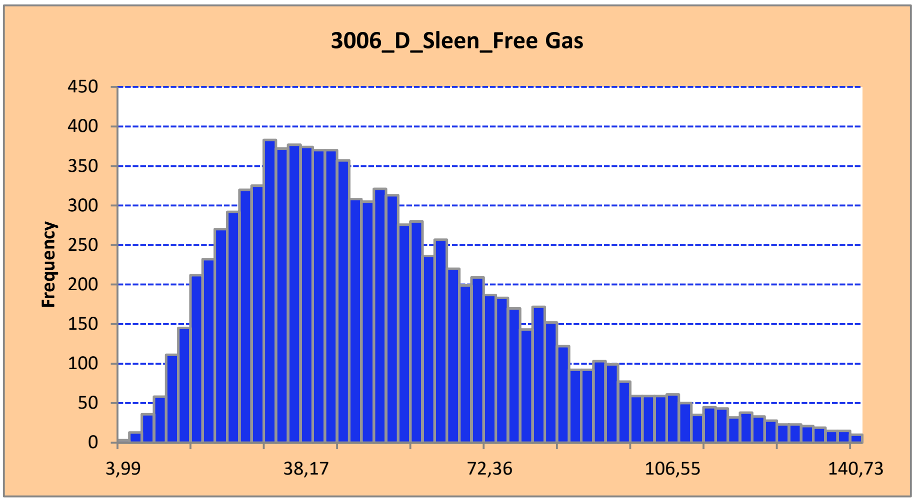
Summary:
Entire range is from 11,88 to 267,54
Base case is 374,65
After 10.000 trials, the std. error of the mean is 0,33



Statistics:	Forecast values
Trials	10.000
Base Case	374,65
Mean	72,56
Median	66,30
Mode	---
Standard Deviation	32,85
Variance	1.079,39
Skewness	1,20
Kurtosis	5,17
Coeff. of Variation	0,4528
Minimum	11,88
Maximum	267,54
Range Width	255,66
Mean Std. Error	0,33

Forecast: 3006_D_Sleen_Free Gas

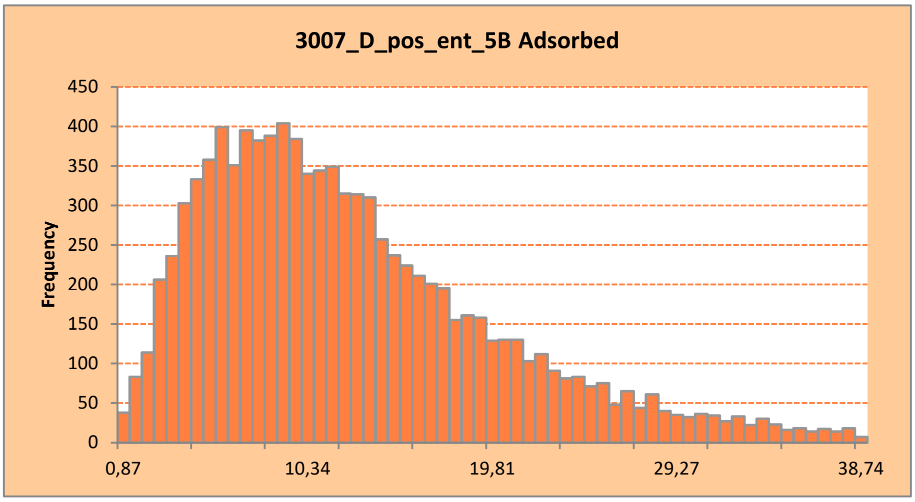
Summary:
Entire range is from 2,85 to 261,43
Base case is 374,61
After 10.000 trials, the std. error of the mean is 0,31



Statistics:	Forecast values
Trials	10.000
Base Case	374,61
Mean	55,29
Median	48,97
Mode	---
Standard Deviation	30,92
Variance	956,19
Skewness	1,39
Kurtosis	6,00
Coeff. of Variation	0,5593
Minimum	2,85
Maximum	261,43
Range Width	258,58
Mean Std. Error	0,31

Forecast: 3007_D_pos_ent_5B Adsorbed

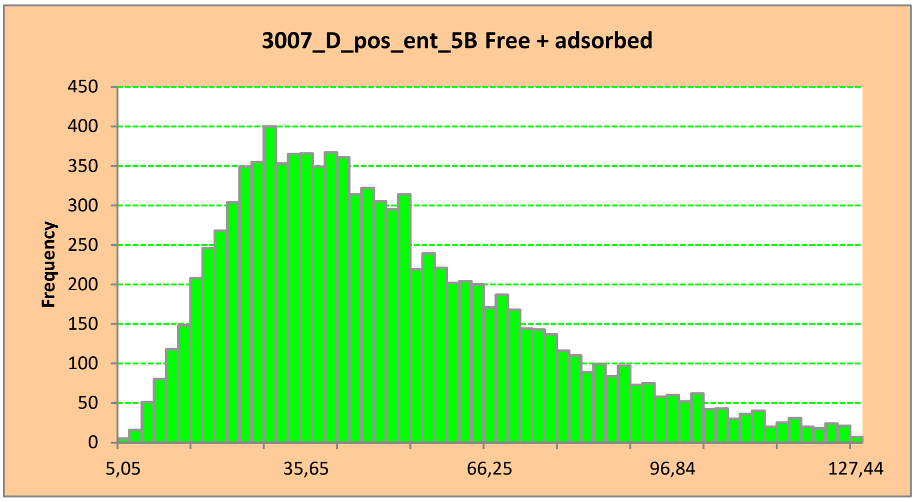
Summary:
Entire range is from 0,56 to 124,02
Base case is 0,03
After 10.000 trials, the std. error of the mean is 0,09



Statistics:	Forecast values
Trials	10.000
Base Case	0,03
Mean	13,28
Median	11,17
Mode	---
Standard Deviation	9,21
Variance	84,74
Skewness	2,12
Kurtosis	12,51
Coeff. of Variation	0,6931
Minimum	0,56
Maximum	124,02
Range Width	123,46
Mean Std. Error	0,09

Forecast: 3007_D_pos_ent_5B Free + adsorbed

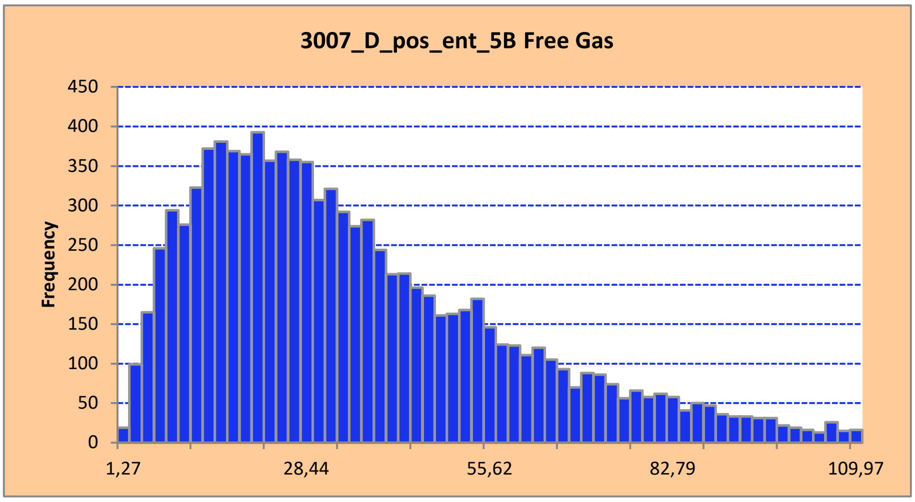
Summary:
Entire range is from 4,03 to 218,97
Base case is 374,65
After 10.000 trials, the std. error of the mean is 0,28



Statistics:	Forecast values
Trials	10.000
Base Case	374,65
Mean	50,60
Median	44,70
Mode	---
Standard Deviation	27,81
Variance	773,37
Skewness	1,33
Kurtosis	5,68
Coeff. of Variation	0,5496
Minimum	4,03
Maximum	218,97
Range Width	214,94
Mean Std. Error	0,28

Forecast: 3007_D_pos_ent_5B Free Gas

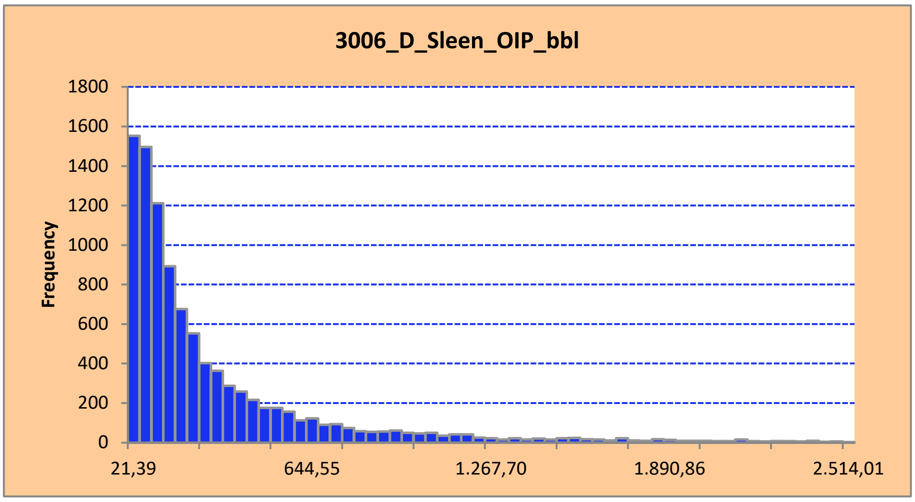
Summary:
Entire range is from 0,36 to 205,61
Base case is 374,61
After 10.000 trials, the std. error of the mean is 0,26



Statistics:	Forecast values
Trials	10.000
Base Case	374,61
Mean	37,31
Median	30,91
Mode	---
Standard Deviation	26,27
Variance	690,19
Skewness	1,48
Kurtosis	6,13
Coeff. of Variation	0,7041
Minimum	0,36
Maximum	205,61
Range Width	205,25
Mean Std. Error	0,26

Forecast: 3006_D_Sleen_OIP_bbl

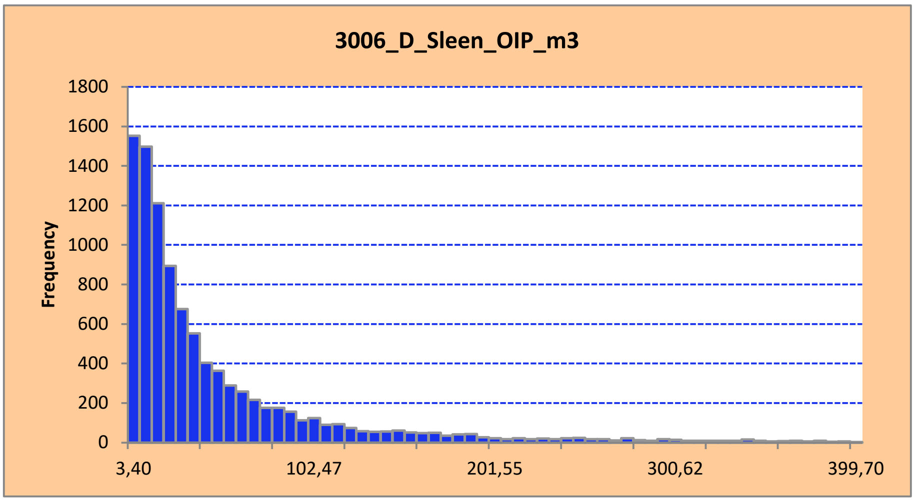
Summary:
Entire range is from 0,62 to 17.145,81
Base case is 3.614,85
After 10.000 trials, the std. error of the mean is 7,70



Statistics:	Forecast values
Trials	10.000
Base Case	3.614,85
Mean	377,67
Median	159,55
Mode	---
Standard Deviation	770,40
Variance	593.514,35
Skewness	7,89
Kurtosis	102,36
Coeff. of Variation	2,04
Minimum	0,62
Maximum	17.145,81
Range Width	17.145,19
Mean Std. Error	7,70

Forecast: 3006_D_Sleen_OIP_m3

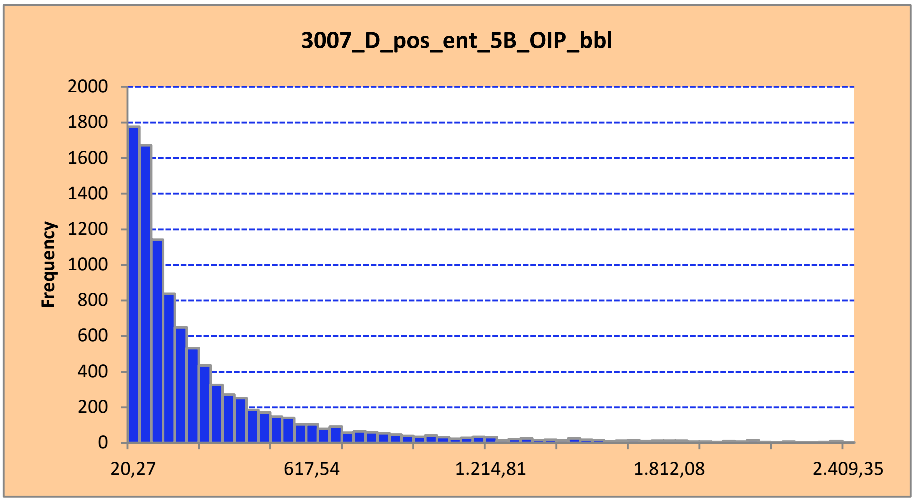
Summary:
Entire range is from 0,10 to 2.725,97
Base case is 574,72
After 10.000 trials, the std. error of the mean is 1,22



Statistics:	Forecast values
Trials	10.000
Base Case	574,72
Mean	60,04
Median	25,37
Mode	---
Standard Deviation	122,48
Variance	15.002,24
Skewness	7,89
Kurtosis	102,36
Coeff. of Variation	2,04
Minimum	0,10
Maximum	2.725,97
Range Width	2.725,87
Mean Std. Error	1,22

Forecast: 3007_D_pos_ent_5B_OIP_bbl

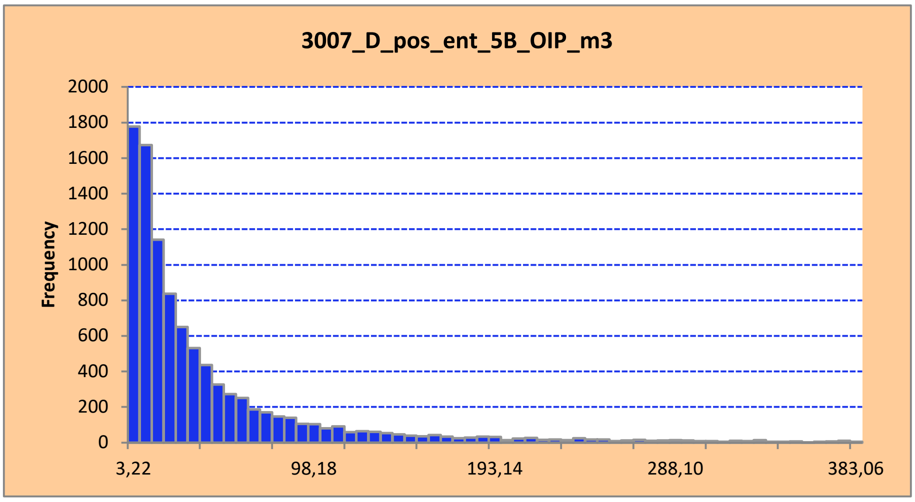
Summary:
Entire range is from 0,36 to 20.602,05
Base case is 3.614,85
After 10.000 trials, the std. error of the mean is 7,46



Statistics:	Forecast values
Trials	10.000
Base Case	3.614,85
Mean	340,43
Median	137,95
Mode	---
Standard Deviation	746,01
Variance	556.531,01
Skewness	10,92
Kurtosis	216,75
Coeff. of Variation	2,19
Minimum	0,36
Maximum	20.602,05
Range Width	20.601,69
Mean Std. Error	7,46

Forecast: 3007_D_pos_ent_5B_OIP_m3

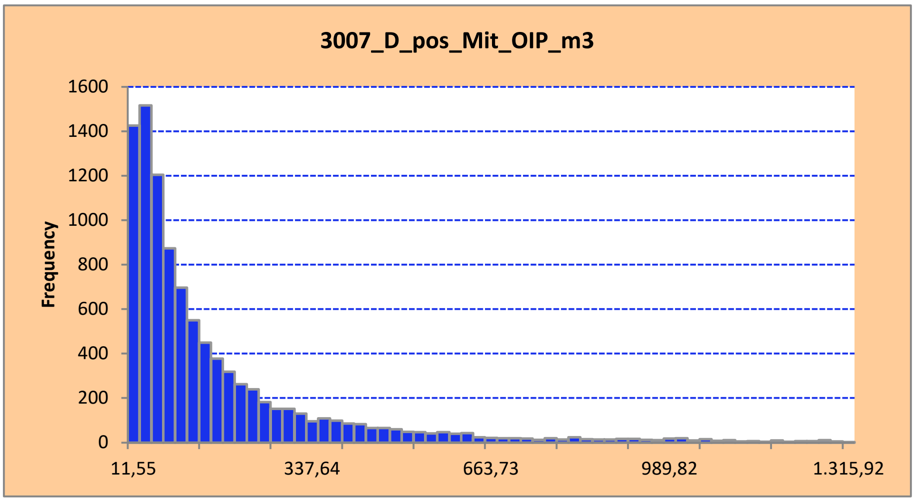
Summary:
Entire range is from 0,06 to 3.275,46
Base case is 574,72
After 10.000 trials, the std. error of the mean is 1,19



Statistics:	Forecast values
Trials	10.000
Base Case	574,72
Mean	54,12
Median	21,93
Mode	---
Standard Deviation	118,61
Variance	14.067,41
Skewness	10,92
Kurtosis	216,75
Coeff. of Variation	2,19
Minimum	0,06
Maximum	3.275,46
Range Width	3.275,41
Mean Std. Error	1,19

Forecast: 3007_D_pos_Mit_OIP_m3

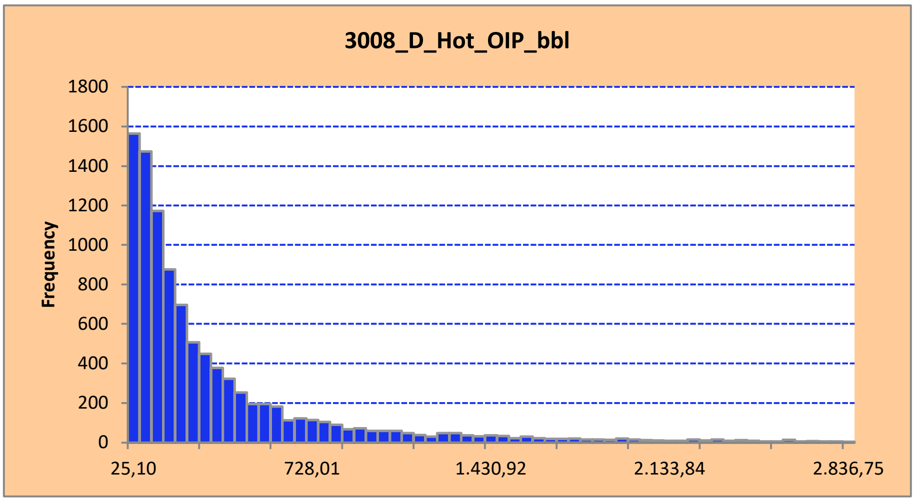
Summary:
Entire range is from 0,68 to 16.838,87
Base case is 195,18
After 10.000 trials, the std. error of the mean is 4,05



Statistics:	Forecast values
Trials	10.000
Base Case	195,18
Mean	191,69
Median	86,92
Mode	---
Standard Deviation	405,39
Variance	164.341,30
Skewness	15,29
Kurtosis	464,10
Coeff. of Variation	2,11
Minimum	0,68
Maximum	16.838,87
Range Width	16.838,19
Mean Std. Error	4,05

Forecast: 3008_D_Hot_OIP_bbl

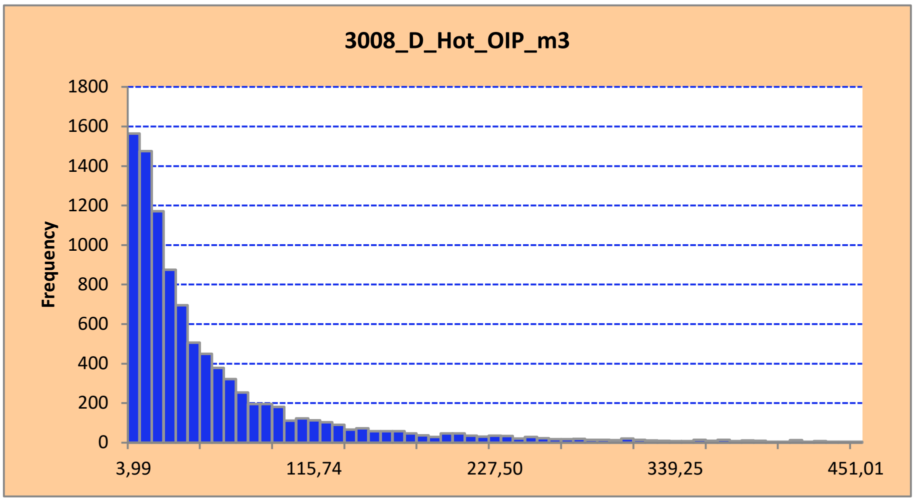
Summary:
Entire range is from 1,67 to 19.571,11
Base case is 3.614,85
After 10.000 trials, the std. error of the mean is 8,67



Statistics:	Forecast values
Trials	10.000
Base Case	3.614,85
Mean	431,87
Median	184,81
Mode	---
Standard Deviation	867,25
Variance	752.125,15
Skewness	7,88
Kurtosis	106,01
Coeff. of Variation	2,01
Minimum	1,67
Maximum	19.571,11
Range Width	19.569,44
Mean Std. Error	8,67

Forecast: 3008_D_Hot_OIP_m3

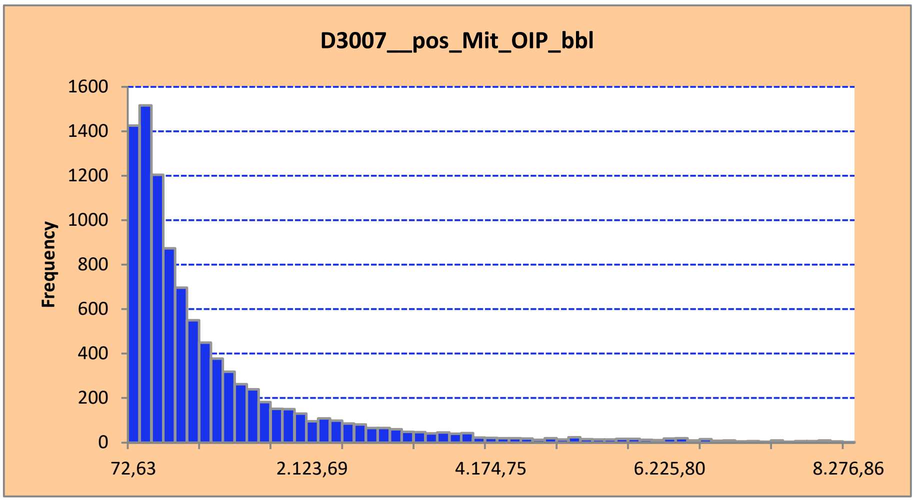
Summary:
Entire range is from 0,27 to 3.111,56
Base case is 574,72
After 10.000 trials, the std. error of the mean is 1,38



Statistics:	Forecast values
Trials	10.000
Base Case	574,72
Mean	68,66
Median	29,38
Mode	---
Standard Deviation	137,88
Variance	19.011,44
Skewness	7,88
Kurtosis	106,01
Coeff. of Variation	2,01
Minimum	0,27
Maximum	3.111,56
Range Width	3.111,29
Mean Std. Error	1,38

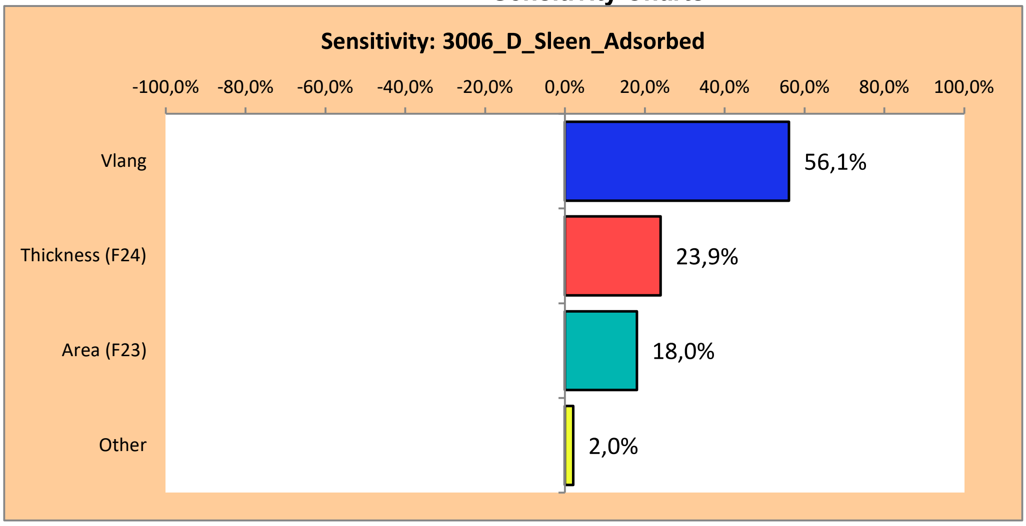
Forecast: D3007__pos_Mit_OIP_bbl

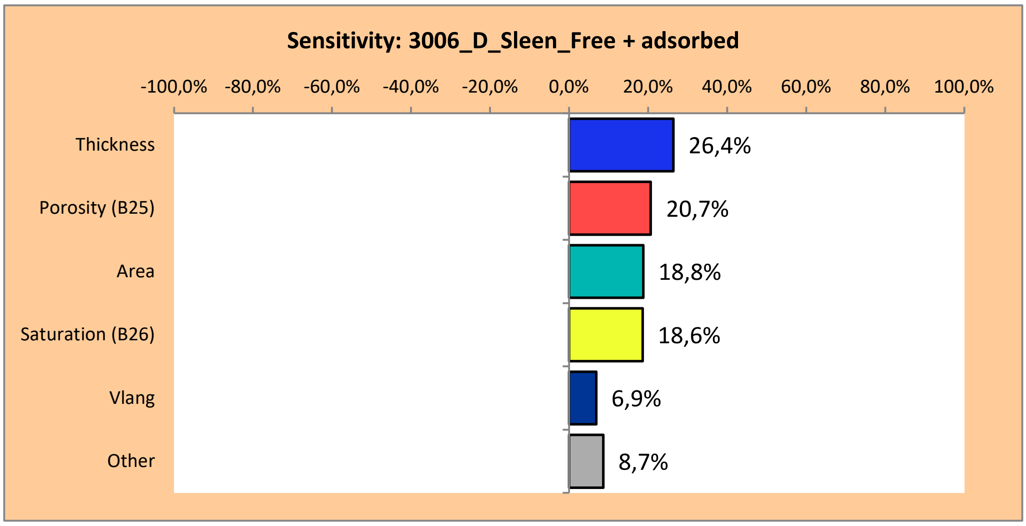
Summary:
Entire range is from 4,26 to 105.913,31
Base case is 1.227,62
After 10.000 trials, the std. error of the mean is 25,50

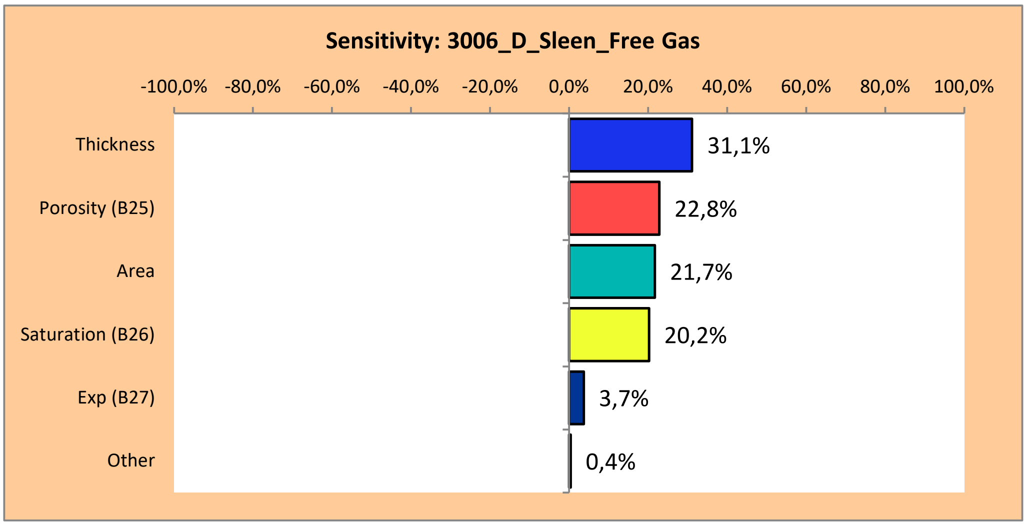


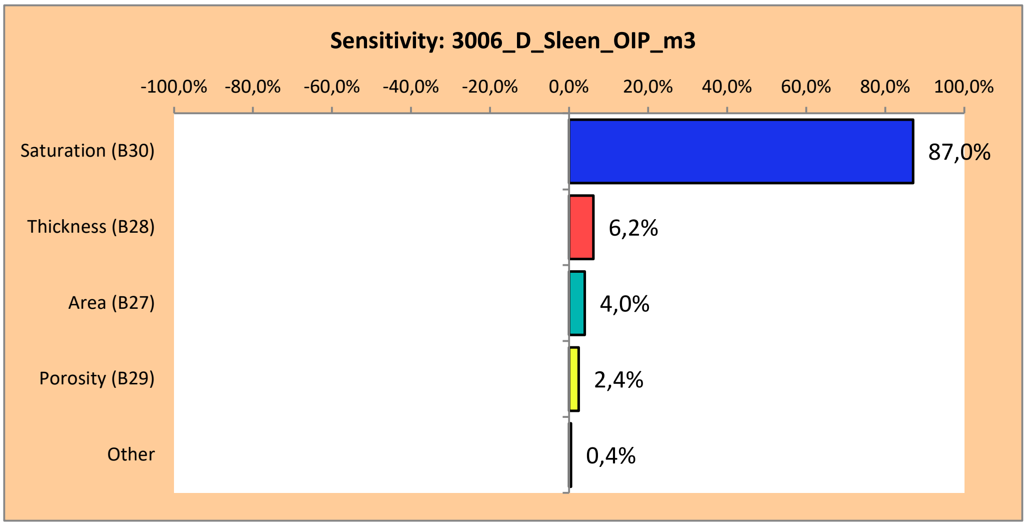
Statistics:	Forecast values
Trials	10.000
Base Case	1.227,62
Mean	1.205,71
Median	546,74
Mode	---
Standard Deviation	2.549,83
Variance	6.501.624,10
Skewness	15,29
Kurtosis	464,10
Coeff. of Variation	2,11
Minimum	4,26
Maximum	105.913,31
Range Width	105.909,05
Mean Std. Error	25,50

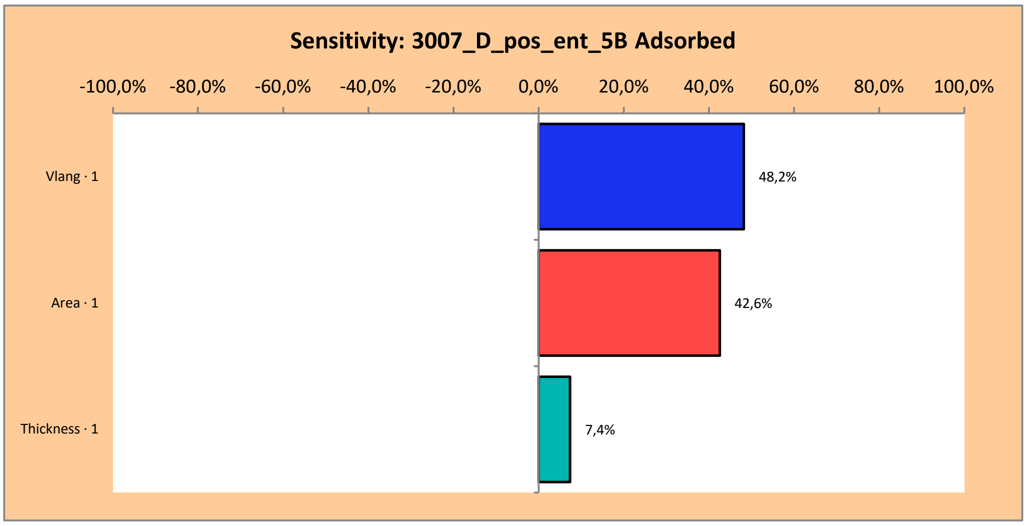
Sensitivity Charts

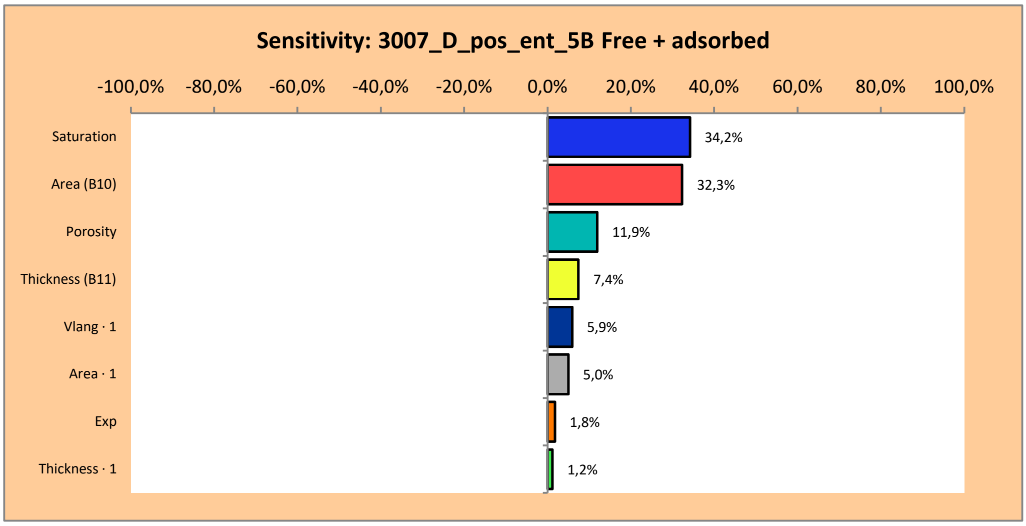


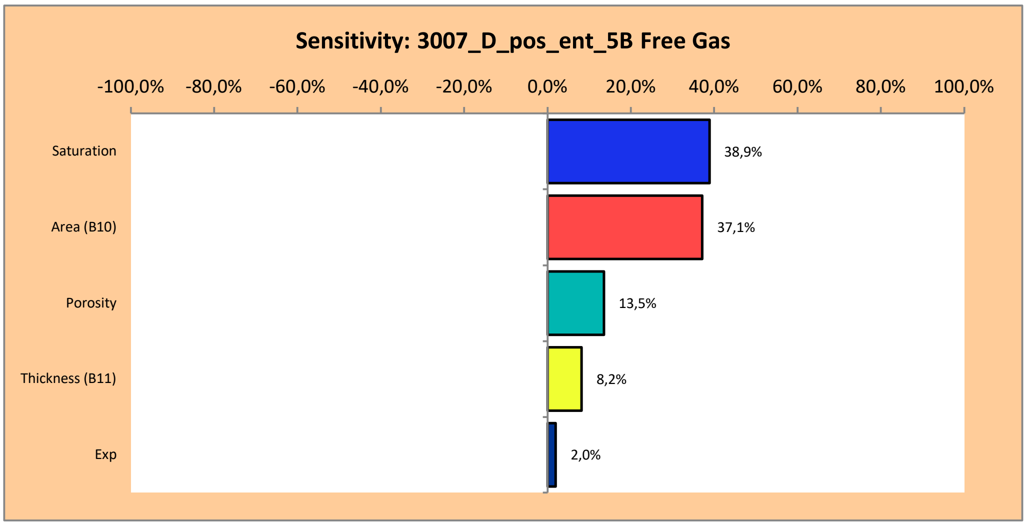


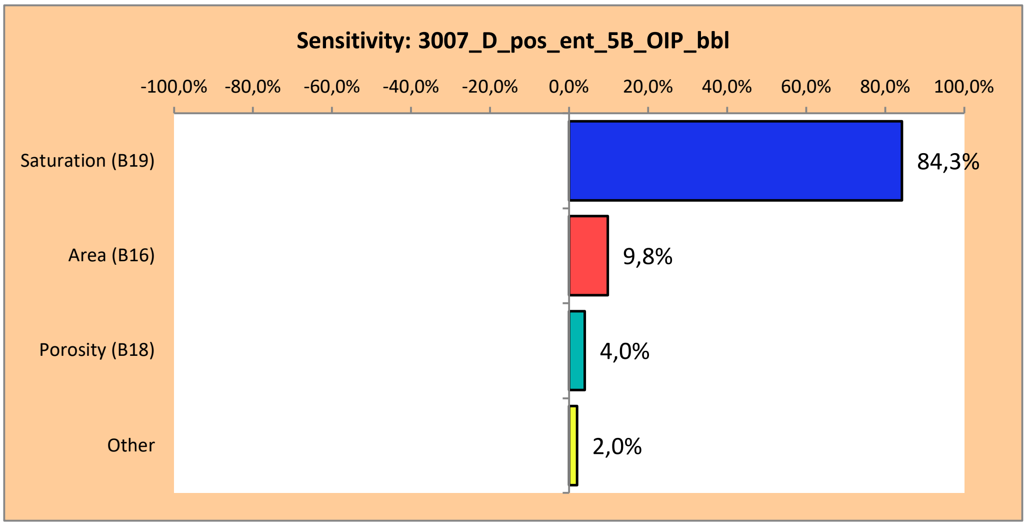

Sensitivity: 3006_D_Sleen_Free Gas
-100,0% -80,0% -60,0% -40,0% -20,0% 0,0% 20,0% 40,0% 60,0% 80,0% 100,0%
Thickness
31,1%
Porosity (B25)
22,8%
Area
21,7%
Saturation (B26)
20,2%
Exp (B27)
3,7%
Other
0,4%

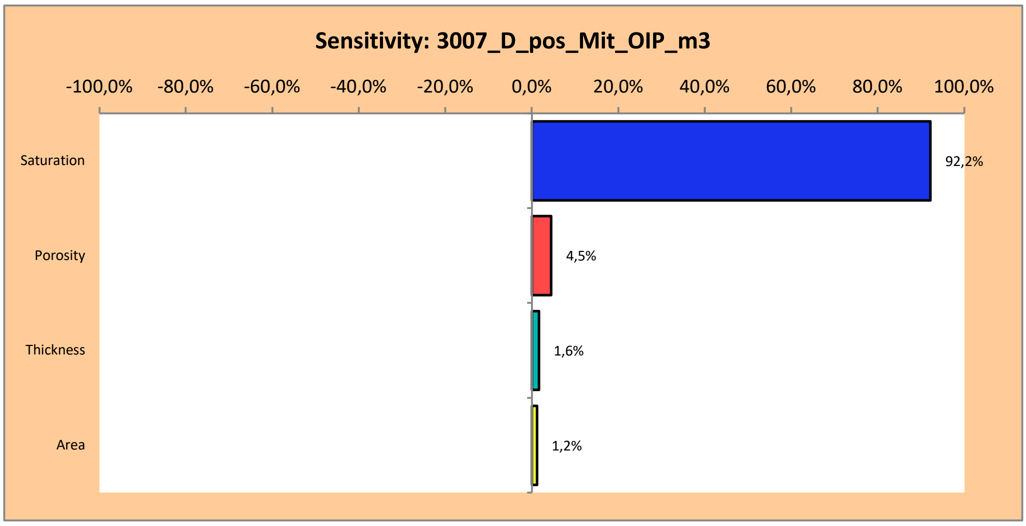

Sensitivity: 3006_D_Sleen_OIP_m3
-100,0% -80,0% -60,0% -40,0% -20,0% 0,0% 20,0% 40,0% 60,0% 80,0% 100,0%
Saturation (B30)
87,0%
Thickness (B28)
6,2%
Area (B27)
4,0%
Porosity (B29)
2,4%
Other
0,4%

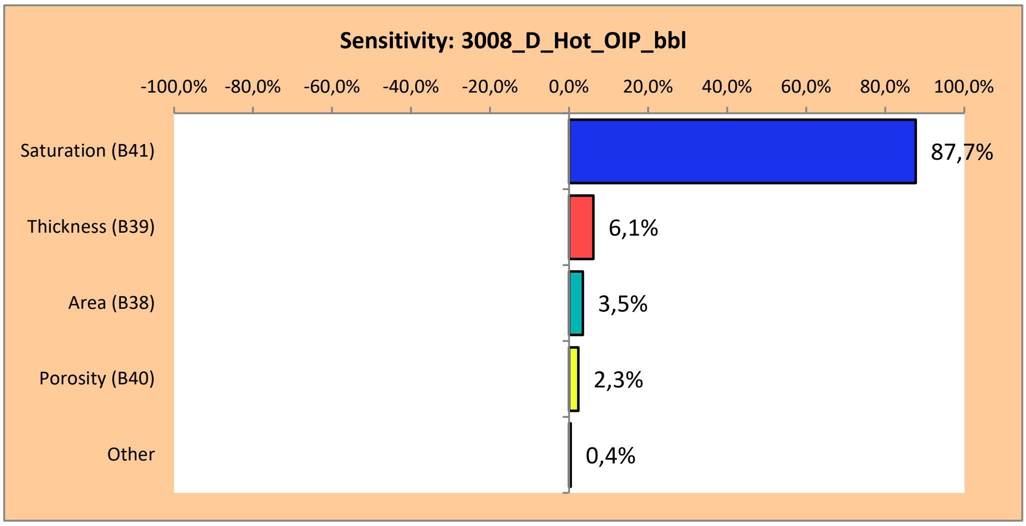

Sensitivity: 3007_D_pos_ent_5B Adsorbed
-100,0%
-80,0%
-60,0%
-40,0%
-20,0%
0,0%
20,0%
40,0%
60,0%
80,0%
100,0%
Vlang · 1
48,2%
Area · 1
42,6%
Thickness · 1
7,4%

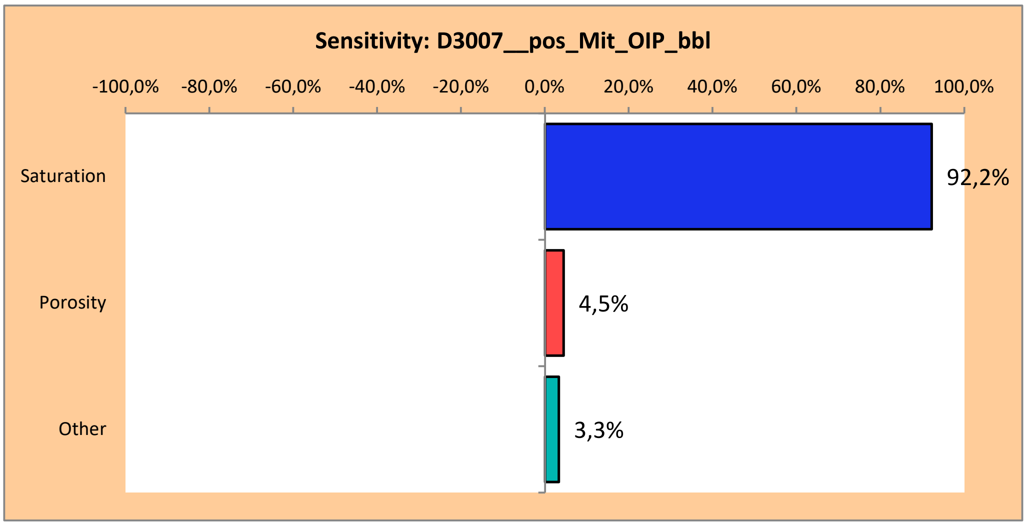

Sensitivity: 3007_D_pos_ent_5B Free + adsorbed
-100,0%
-80,0%
-60,0%
-40,0%
-20,0%
0,0%
20,0%
40,0%
60,0%
80,0%
100,0%
Saturation
34,2%
Area (B10)
32,3%
Porosity
11,9%
Thickness (B11)
7,4%
Vlang · 1
5,9%
Area · 1
5,0%
Exp
1,8%
Thickness · 1
1,2%


Sensitivity: 3007_D_pos_ent_5B Free Gas
-100,0%
-80,0%
-60,0%
-40,0%
-20,0%
0,0%
20,0%
40,0%
60,0%
80,0%
100,0%
Saturation
38,9%
Area (B10)
37,1%
Porosity
13,5%
Thickness (B11)
8,2%
Exp
2,0%


Sensitivity: 3007_D_pos_ent_5B_OIP_bbl
-100,0%
-80,0%
-60,0%
-40,0%
-20,0%
0,0%
20,0%
40,0%
60,0%
80,0%
100,0%
Saturation (B19)
84,3%
Area (B16)
9,8%
Porosity (B18)
4,0%
Other
2,0%


Sensitivity: 3007_D_pos_Mit_OIP_m3
-100,0%
-80,0%
-60,0%
-40,0%
-20,0%
0,0%
20,0%
40,0%
60,0%
80,0%
100,0%
Saturation
92,2%
Porosity
4,5%
Thickness
1,6%
Area
1,2%


Sensitivity: 3008_D_Hot_OIP_bbl
-100,0%
-80,0%
-60,0%
-40,0%
-20,0%
0,0%
20,0%
40,0%
60,0%
80,0%
100,0%
Saturation (B41)
87,7%
Thickness (B39)
6,1%
Area (B38)
3,5%
Porosity (B40)
2,3%
Other
0,4%

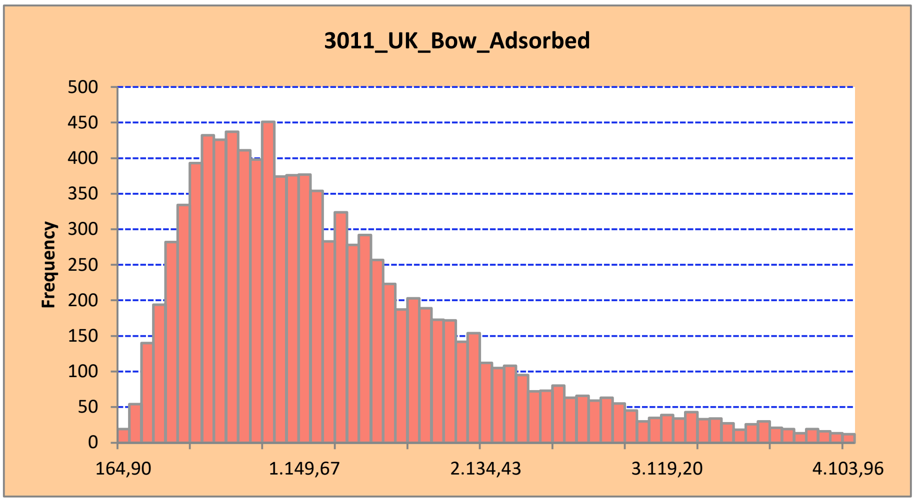


End of Sensitivity Charts

Forecasts

Forecast: 3011_UK_Bow_Adsorbed

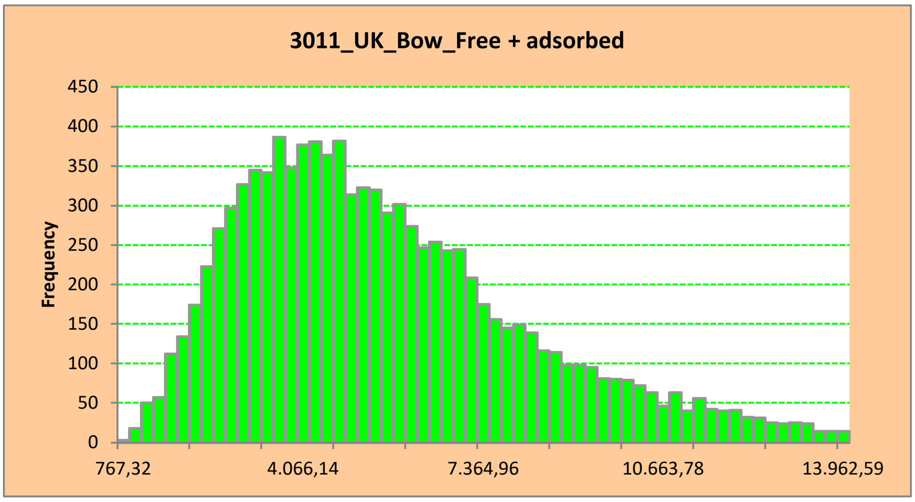
Summary:
- Certainty level is 0,00%
- Certainty range is from ∞ to ∞
- Entire range is from 132,08 to 11.591,30
- Base case is 0,03
- After 10.000 trials, the std. error of the mean is 9,73



Statistics:	Forecast values
Trials	10.000
Base Case	0,03
Mean	1.411,60
Median	1.163,76
Mode	---
Standard Deviation	973,28
Variance	947.273,24
Skewness	2,33
Kurtosis	13,05
Coeff. of Variation	0,6895
Minimum	132,08
Maximum	11.591,30
Range Width	11.459,22
Mean Std. Error	9,73

Forecast: 3011_UK_Bow_Free + adsorbed

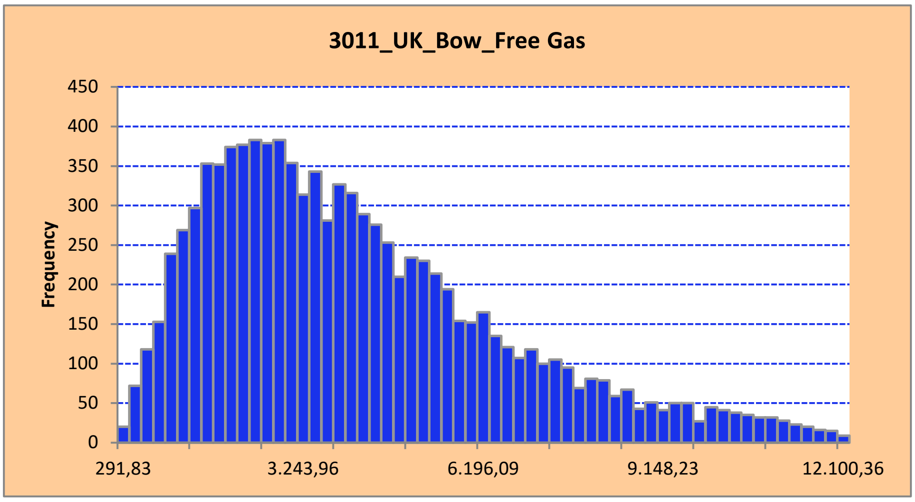
Summary:
Entire range is from 657,36 to 26.756,02
Base case is 374,65
After 10.000 trials, the std. error of the mean is 29,78



Statistics:	Forecast values
Trials	10.000
Base Case	374,65
Mean	5.735,25
Median	5.111,43
Mode	---
Standard Deviation	2.977,61
Variance	8.866.141,36
Skewness	1,32
Kurtosis	5,48
Coeff. of Variation	0,5192
Minimum	657,36
Maximum	26.756,02
Range Width	26.098,65
Mean Std. Error	29,78

Forecast: 3011_UK_Bow_Free Gas

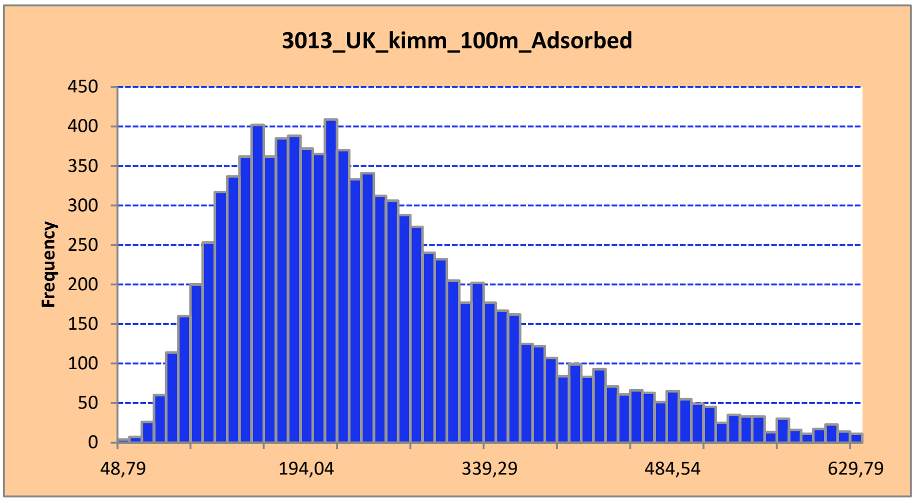
Summary:
Entire range is from 193,42 to 23.550,69
Base case is 374,61
After 10.000 trials, the std. error of the mean is 28,13



Statistics:	Forecast values
Trials	10.000
Base Case	374,61
Mean	4.323,65
Median	3.695,27
Mode	---
Standard Deviation	2.812,54
Variance	7.910.383,56
Skewness	1,47
Kurtosis	6,04
Coeff. of Variation	0,6505
Minimum	193,42
Maximum	23.550,69
Range Width	23.357,26
Mean Std. Error	28,13

Forecast: 3013_UK_kimm_100m_Adsorbed

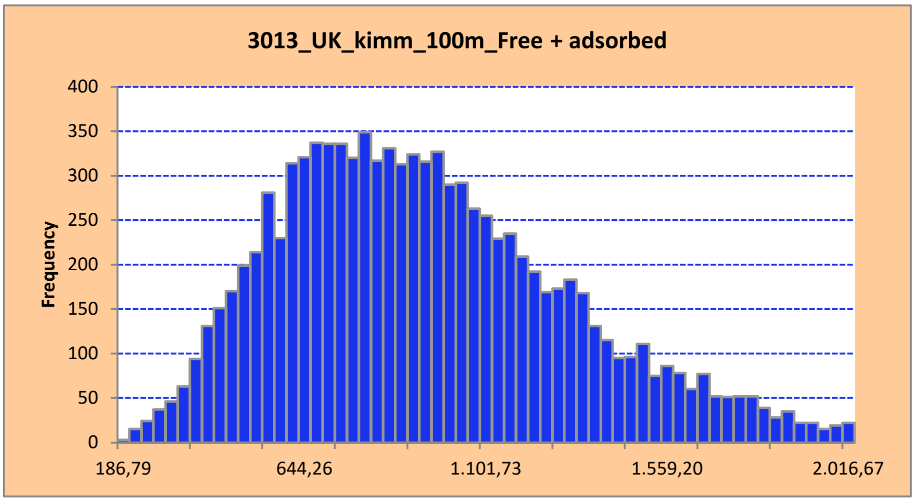
Summary:
Entire range is from 43,95 to 1.623,77
Base case is 0,03
After 10.000 trials, the std. error of the mean is 1,34



Statistics:	Forecast values
Trials	10.000
Base Case	0,03
Mean	260,35
Median	230,70
Mode	---
Standard Deviation	133,67
Variance	17.867,76
Skewness	1,83
Kurtosis	9,32
Coeff. of Variation	0,5134
Minimum	43,95
Maximum	1.623,77
Range Width	1.579,82
Mean Std. Error	1,34

Forecast: 3013_UK_kimm_100m_Free + adsorbed

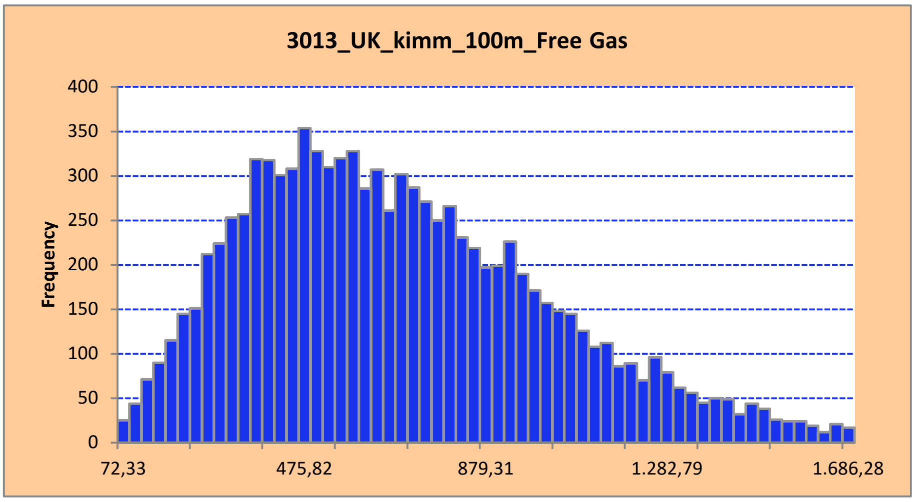
Summary:
Entire range is from 171,54 to 3.044,32
Base case is 374,65
After 10.000 trials, the std. error of the mean is 3,83



Statistics:	Forecast values
Trials	10.000
Base Case	374,65
Mean	960,79
Median	910,03
Mode	---
Standard Deviation	382,54
Variance	146.340,32
Skewness	0,7915
Kurtosis	3,76
Coeff. of Variation	0,3982
Minimum	171,54
Maximum	3.044,32
Range Width	2.872,77
Mean Std. Error	3,83

Forecast: 3013_UK_kimm_100m_Free Gas

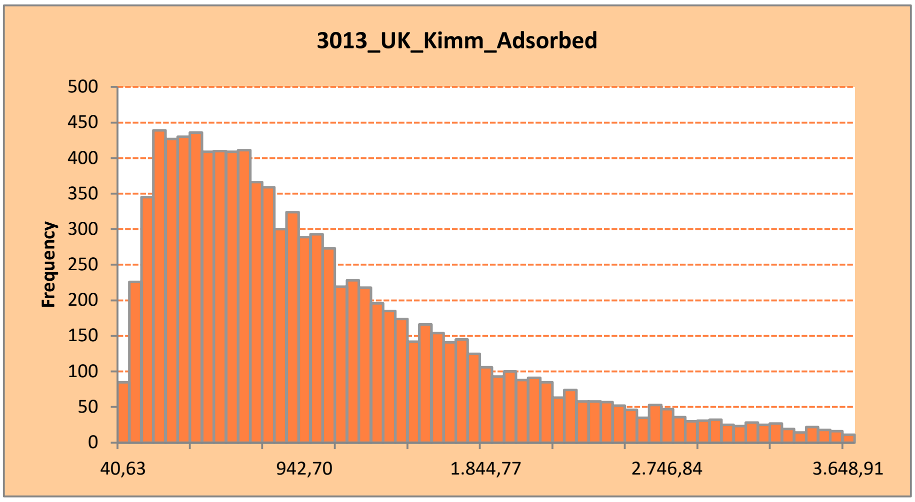
Summary:
Entire range is from 58,88 to 2.584,65
Base case is 374,61
After 10.000 trials, the std. error of the mean is 3,57



Statistics:	Forecast values
Trials	10.000
Base Case	374,61
Mean	700,44
Median	645,47
Mode	---
Standard Deviation	356,89
Variance	127.370,64
Skewness	0,8782
Kurtosis	3,93
Coeff. of Variation	0,5095
Minimum	58,88
Maximum	2.584,65
Range Width	2.525,76
Mean Std. Error	3,57

Forecast: 3013_UK_Kimm_Adsorbed

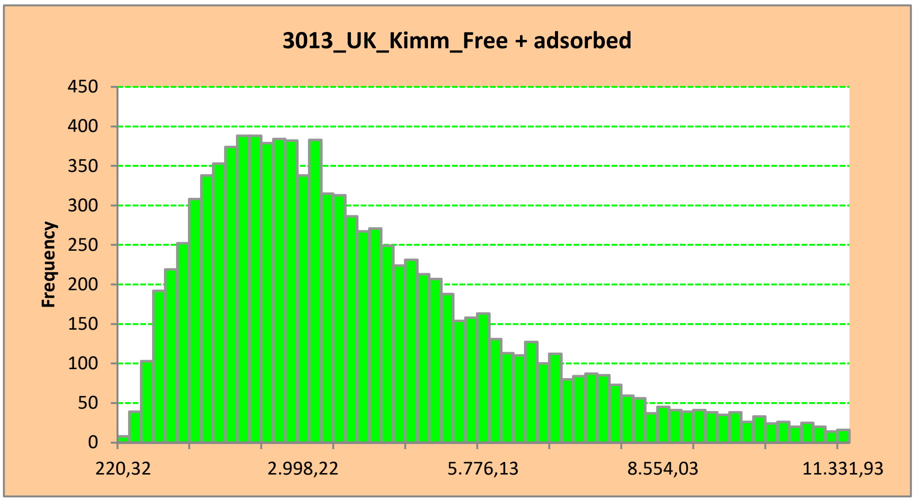
Summary:
Entire range is from 10,56 to 9.137,57
Base case is 0,03
After 10.000 trials, the std. error of the mean is 9,22



Statistics:	Forecast values
Trials	10.000
Base Case	0,03
Mean	1.096,99
Median	840,61
Mode	---
Standard Deviation	922,14
Variance	850.338,76
Skewness	1,97
Kurtosis	9,19
Coeff. of Variation	0,8406
Minimum	10,56
Maximum	9.137,57
Range Width	9.127,00
Mean Std. Error	9,22

Forecast: 3013_UK_Kimm_Free + adsorbed

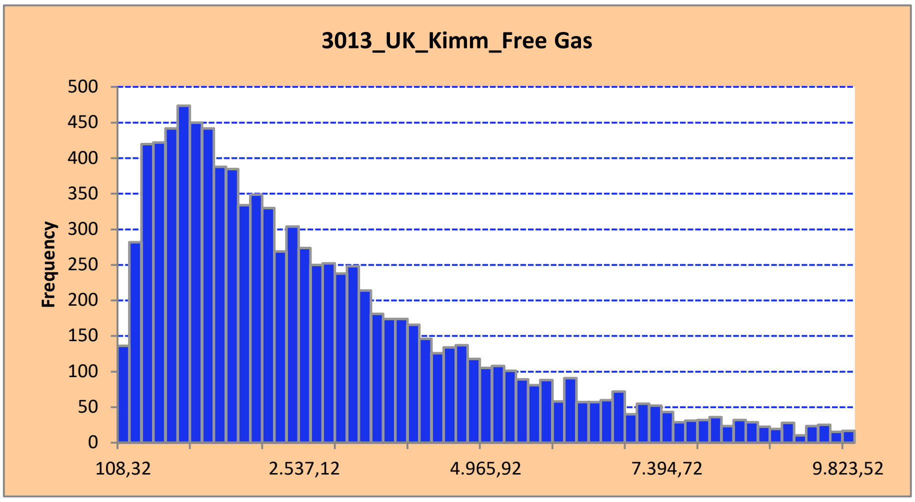
Summary:
Entire range is from 127,72 to 21.868,12
Base case is 374,65
After 10.000 trials, the std. error of the mean is 26,44



Statistics:	Forecast values
Trials	10.000
Base Case	374,65
Mean	4.022,57
Median	3.377,78
Mode	---
Standard Deviation	2.643,56
Variance	6.988.402,08
Skewness	1,51
Kurtosis	6,28
Coeff. of Variation	0,6572
Minimum	127,72
Maximum	21.868,12
Range Width	21.740,40
Mean Std. Error	26,44

Forecast: 3013_UK_Kimm_Free Gas

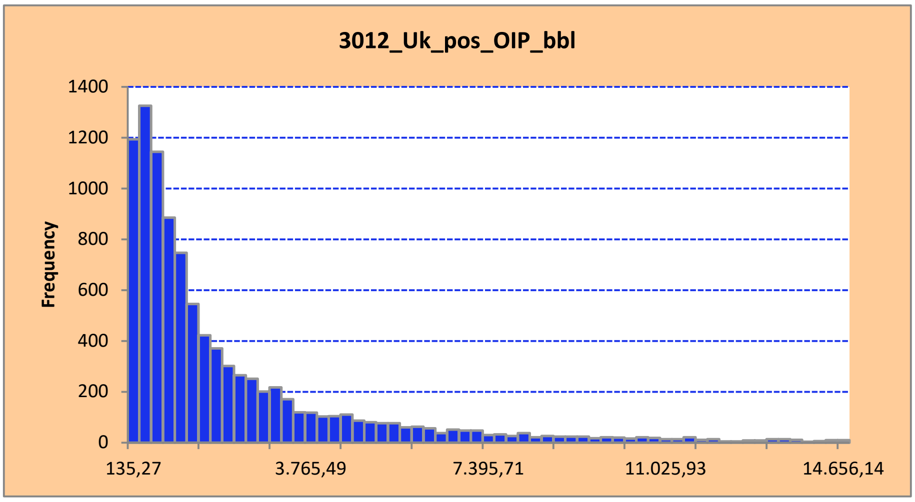
Summary:
Entire range is from 27,36 to 21.173,66
Base case is 374,61
After 10.000 trials, the std. error of the mean is 24,92



Statistics:	Forecast values
Trials	10.000
Base Case	374,61
Mean	2.925,58
Median	2.217,23
Mode	---
Standard Deviation	2.492,47
Variance	6.212.382,59
Skewness	1,71
Kurtosis	6,98
Coeff. of Variation	0,8520
Minimum	27,36
Maximum	21.173,66
Range Width	21.146,29
Mean Std. Error	24,92

Forecast: 3012_Uk_pos_OIP_bbl

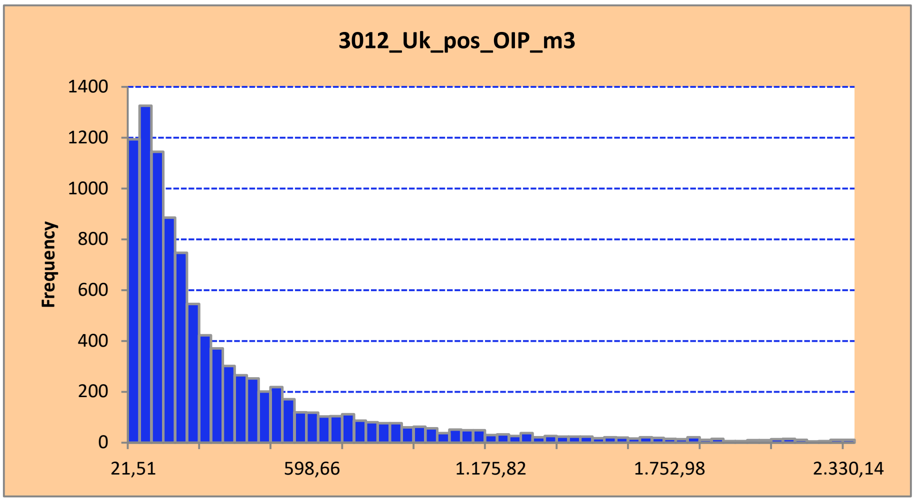
Summary:
Entire range is from 14,26 to 96.213,28
Base case is 1.227,62
After 10.000 trials, the std. error of the mean is 43,85



Statistics:	Forecast values
Trials	10.000
Base Case	1.227,62
Mean	2.499,01
Median	1.126,37
Mode	---
Standard Deviation	4.385,05
Variance	19.228.671,65
Skewness	6,55
Kurtosis	77,17
Coeff. of Variation	1,75
Minimum	14,26
Maximum	96.213,28
Range Width	96.199,02
Mean Std. Error	43,85

Forecast: 3012_Uk_pos_OIP_m3

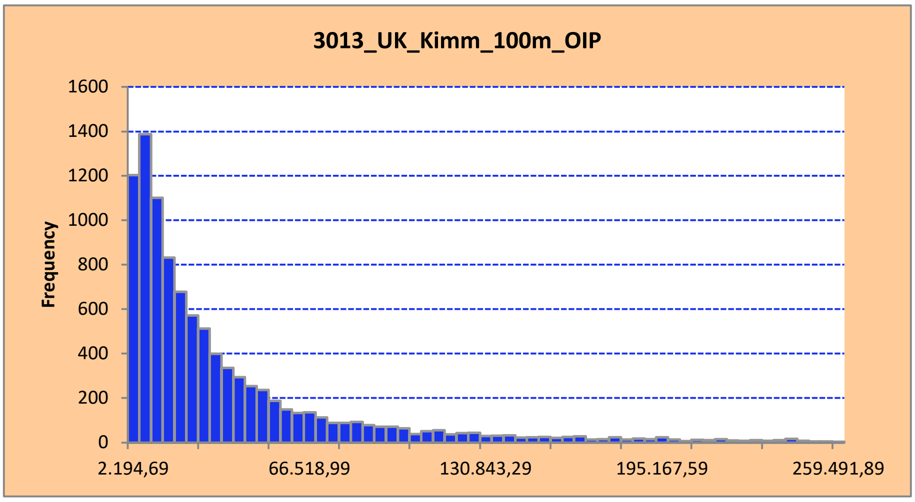
Summary:
Entire range is from 2,27 to 15.296,69
Base case is 195,18
After 10.000 trials, the std. error of the mean is 6,97



Statistics:	Forecast values
Trials	10.000
Base Case	195,18
Mean	397,31
Median	179,08
Mode	---
Standard Deviation	697,17
Variance	486.042,39
Skewness	6,55
Kurtosis	77,17
Coeff. of Variation	1,75
Minimum	2,27
Maximum	15.296,69
Range Width	15.294,42
Mean Std. Error	6,97

Forecast: 3013_UK_Kimm_100m_OIP

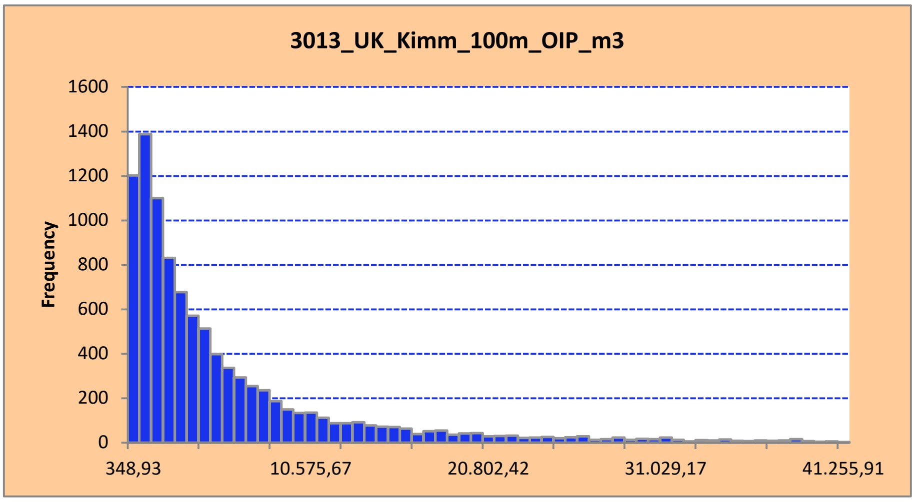
Summary:
Entire range is from 50,54 to 2.728.036,37
Base case is 11.832,77
After 10.000 trials, the std. error of the mean is 781,55



Statistics:	Forecast values
Trials	10.000
Base Case	11.832,77
Mean	42.801,25
Median	20.023,76
Mode	---
Standard Deviation	78.155,28
Variance	6.108.247.754,16
Skewness	8,98
Kurtosis	186,21
Coeff. of Variation	1,83
Minimum	50,54
Maximum	2.728.036,37
Range Width	2.727.985,83
Mean Std. Error	781,55

Forecast: 3013_UK_Kimm_100m_OIP_m3

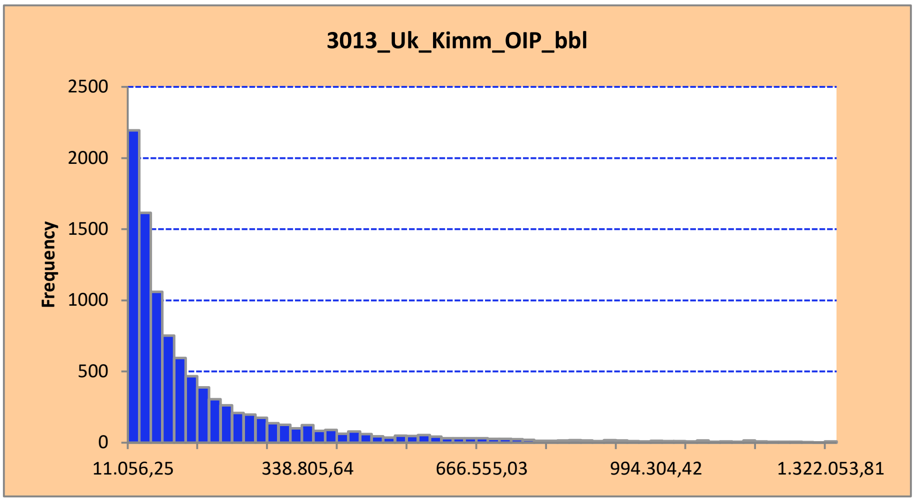
Summary:
Entire range is from 8,04 to 433.723,14
Base case is 1.881,26
After 10.000 trials, the std. error of the mean is 124,26



Statistics:	Forecast values
Trials	10.000
Base Case	1.881,26
Mean	6.804,86
Median	3.183,52
Mode	---
Standard Deviation	12.425,70
Variance	154.397.943,69
Skewness	8,98
Kurtosis	186,21
Coeff. of Variation	1,83
Minimum	8,04
Maximum	433.723,14
Range Width	433.715,10
Mean Std. Error	124,26

Forecast: 3013_Uk_Kimm_OIP_bbl

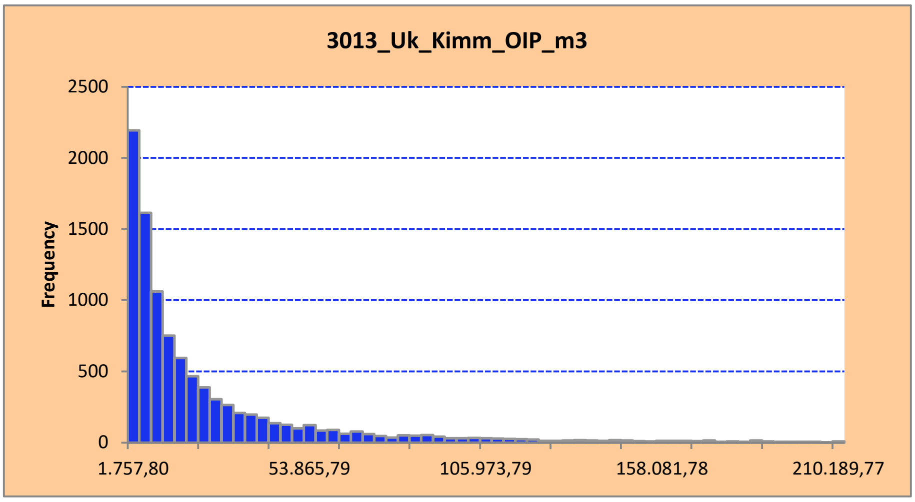
Summary:
Entire range is from 131,27 to 9.876.518,40
Base case is 11.832,77
After 10.000 trials, the std. error of the mean is 4.093,56



Statistics:	Forecast values
Trials	10.000
Base Case	11.832,77
Mean	186.782,09
Median	69.144,16
Mode	---
Standard Deviation	409.355,97
Variance	167.572.307.318,90
Skewness	9,21
Kurtosis	148,28
Coeff. of Variation	2,19
Minimum	131,27
Maximum	9.876.518,40
Range Width	9.876.387,12
Mean Std. Error	4.093,56

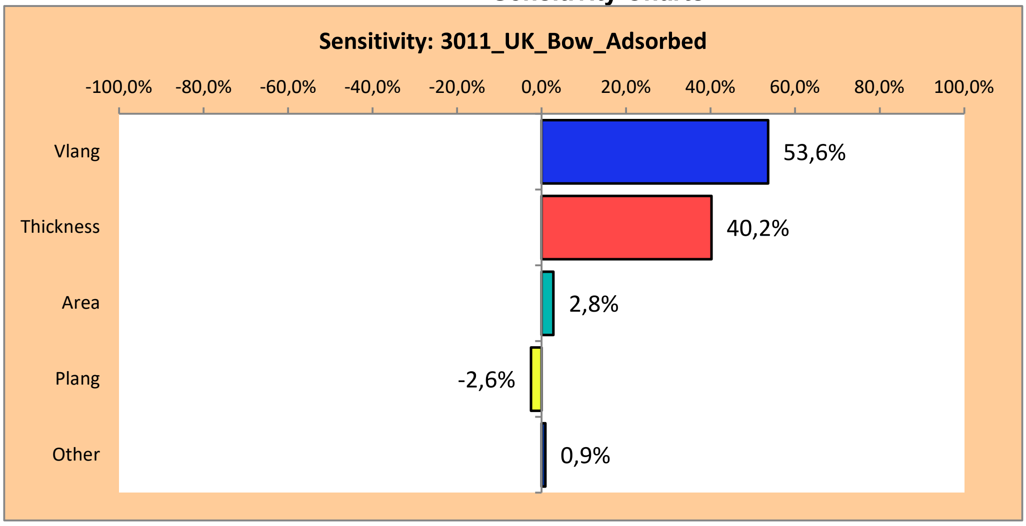
Forecast: 3013_Uk_Kimm_OIP_m3

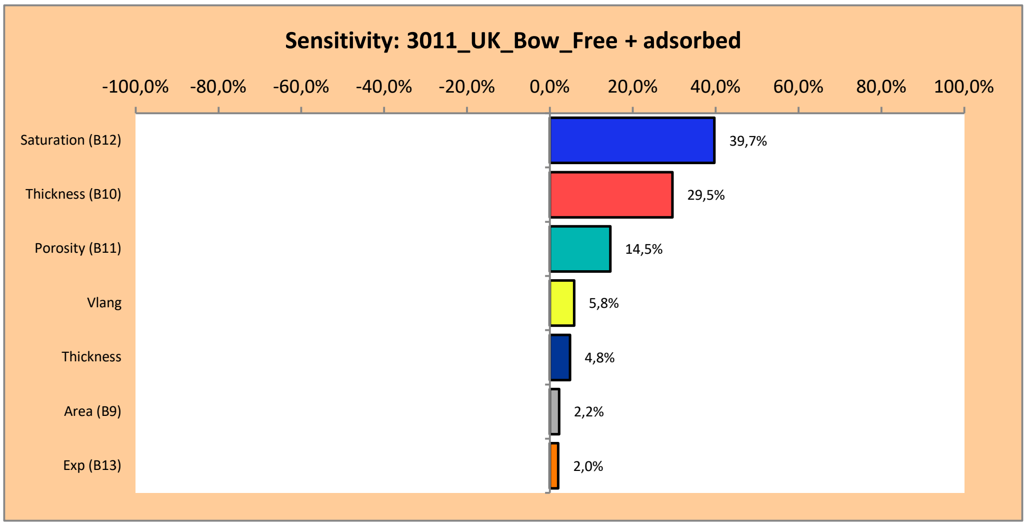
Summary:
Entire range is from 20,87 to 1.570.240,99
Base case is 1.881,26
After 10.000 trials, the std. error of the mean is 650,82

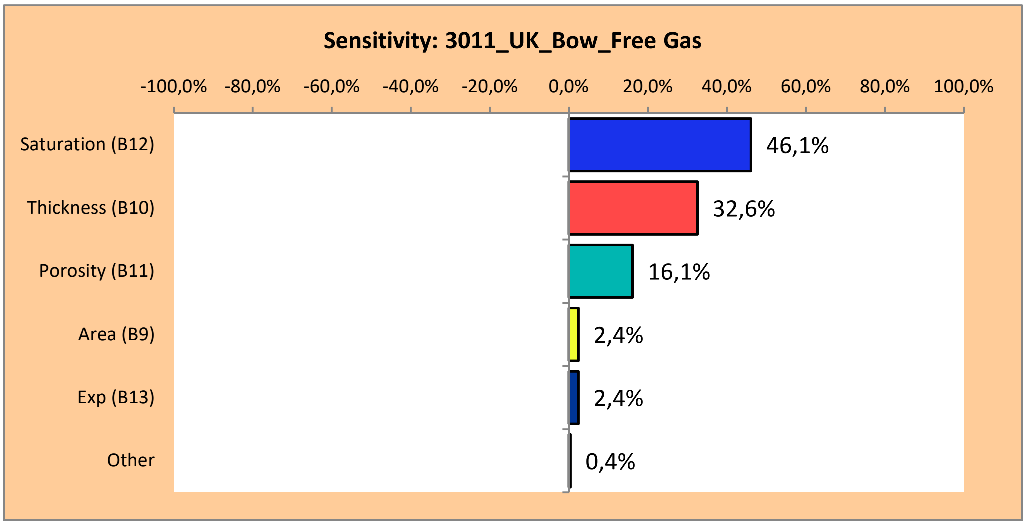


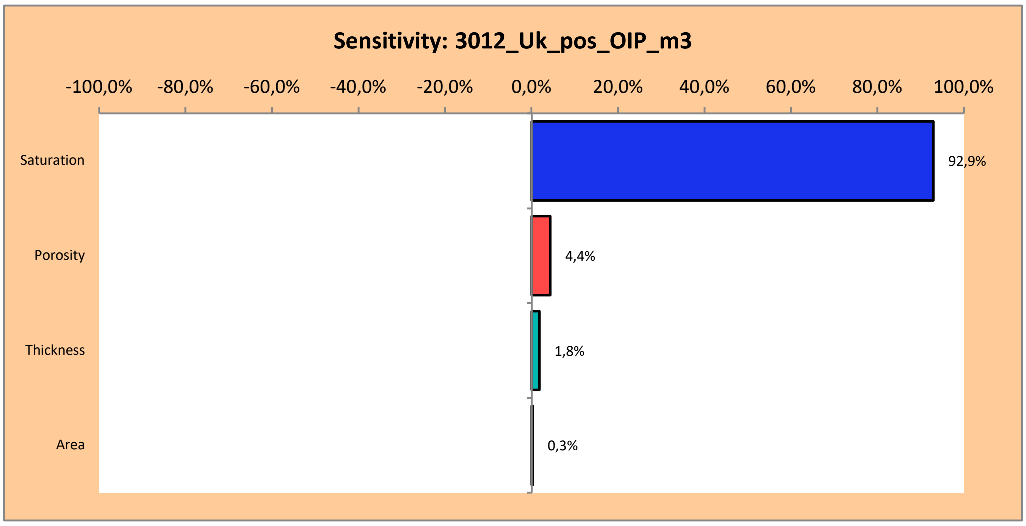
Statistics:	Forecast values
Trials	10.000
Base Case	1.881,26
Mean	29.695,98
Median	10.993,04
Mode	---
Standard Deviation	65.082,40
Variance	4.235.718.770,84
Skewness	9,21
Kurtosis	148,28
Coeff. of Variation	2,19
Minimum	20,87
Maximum	1.570.240,99
Range Width	1.570.220,12
Mean Std. Error	650,82

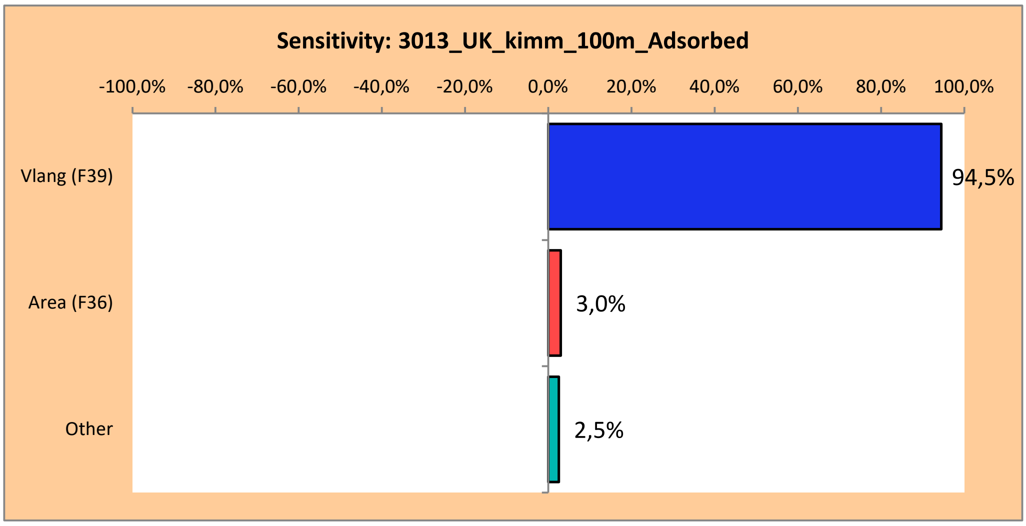
Sensitivity Charts

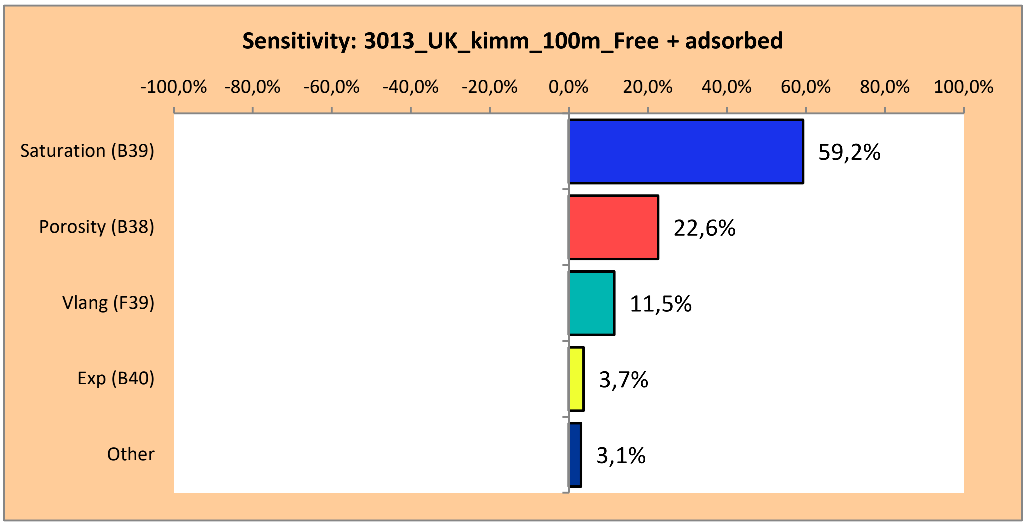


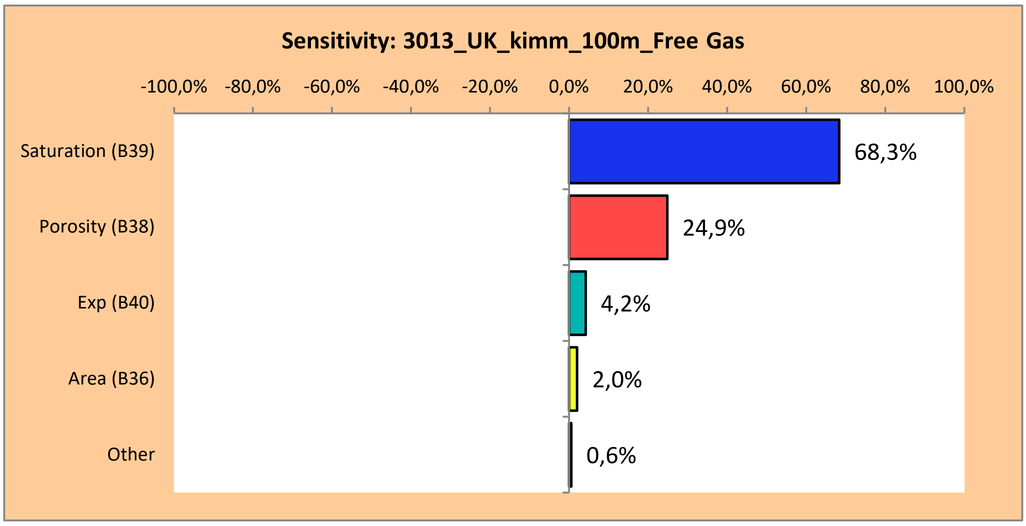


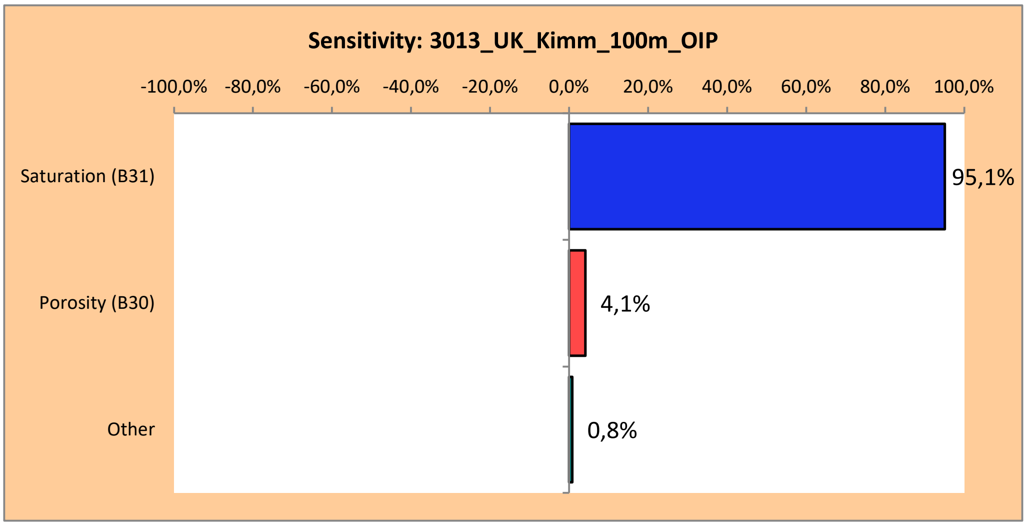

Sensitivity: 3011_UK_Bow_Free Gas
-100,0% -80,0% -60,0% -40,0% -20,0% 0,0% 20,0% 40,0% 60,0% 80,0% 100,0%
Saturation (B12)
46,1%
Thickness (B10)
32,6%
Porosity (B11)
16,1%
Area (B9)
2,4%
Exp (B13)
2,4%
Other
0,4%

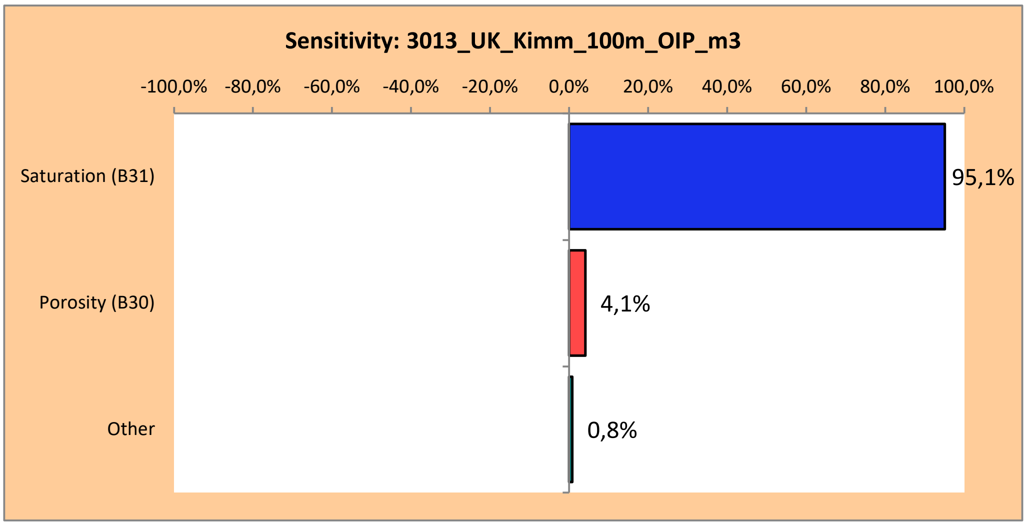

Sensitivity: 3012_Uk_pos_OIP_m3
-100,0% -80,0% -60,0% -40,0% -20,0% 0,0% 20,0% 40,0% 60,0% 80,0% 100,0%
Saturation
92,9%
Porosity
4,4%
Thickness
1,8%
Area
0,3%


Sensitivity: 3013_UK_kimm_100m_Adsorbed
-100,0%
-80,0%
-60,0%
-40,0%
-20,0%
0,0%
20,0%
40,0%
60,0%
80,0%
100,0%
Vlang (F39)
94,5%
Area (F36)
3,0%
Other
2,5%

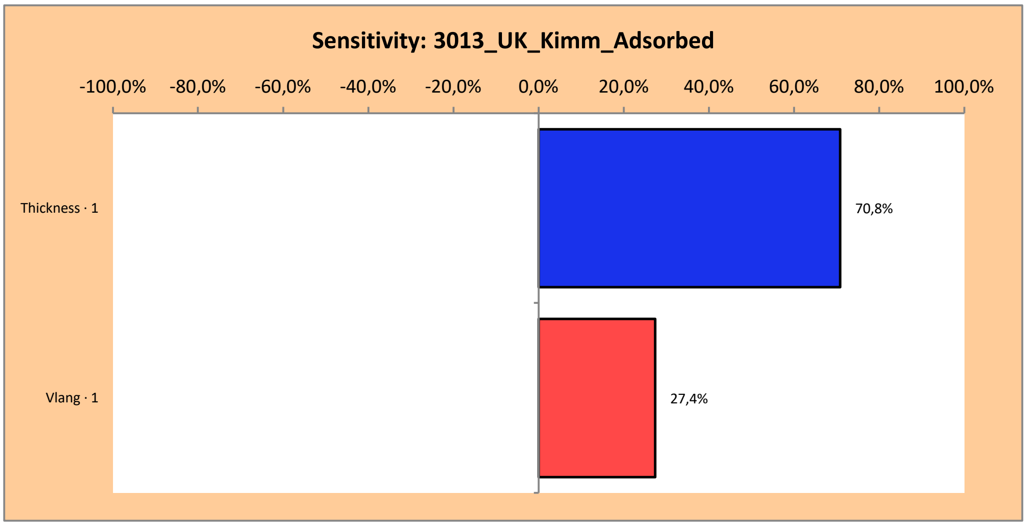

Sensitivity: 3013_UK_kimm_100m_Free + adsorbed
-100,0%
-80,0%
-60,0%
-40,0%
-20,0%
0,0%
20,0%
40,0%
60,0%
80,0%
100,0%
Saturation (B39)
59,2%
Porosity (B38)
22,6%
Vlang (F39)
11,5%
Exp (B40)
3,7%
Other
3,1%


Sensitivity: 3013_UK_kimm_100m_Free Gas
-100,0% -80,0% -60,0% -40,0% -20,0% 0,0% 20,0% 40,0% 60,0% 80,0% 100,0%
Saturation (B39)
68,3%
Porosity (B38)
24,9%
Exp (B40)
4,2%
Area (B36)
2,0%
Other
0,6%

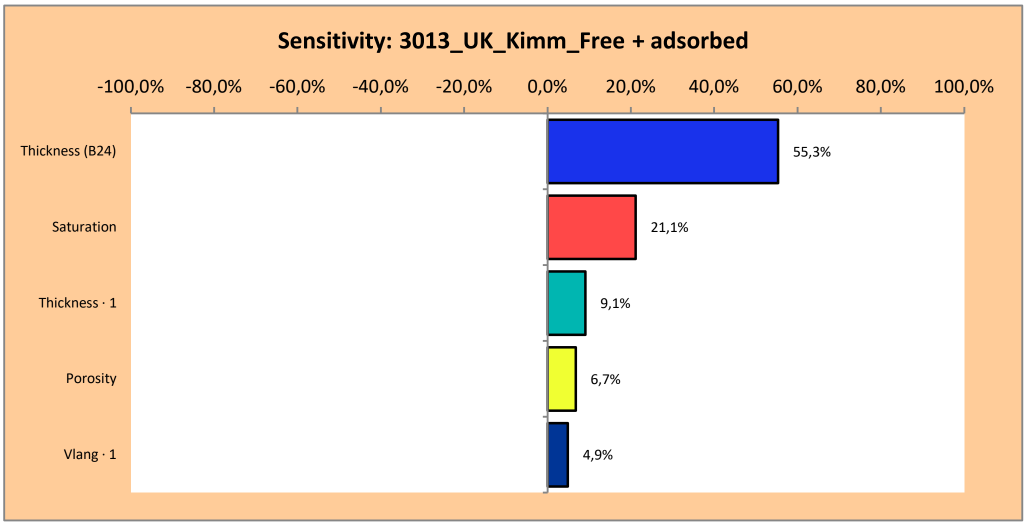

Sensitivity: 3013_UK_Kimm_100m_OIP
-100,0% -80,0% -60,0% -40,0% -20,0% 0,0% 20,0% 40,0% 60,0% 80,0% 100,0%
Saturation (B31)
95,1%
Porosity (B30)
4,1%
Other
0,8%

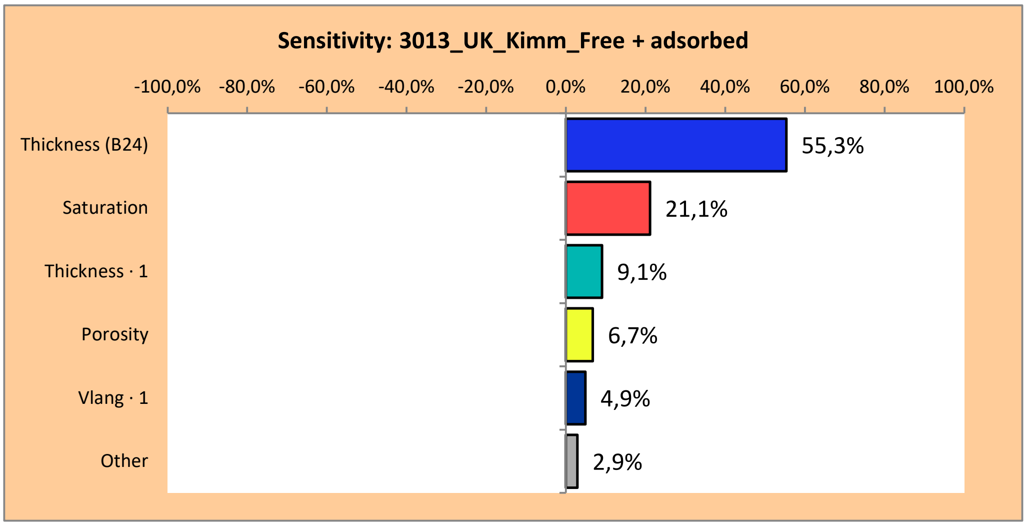


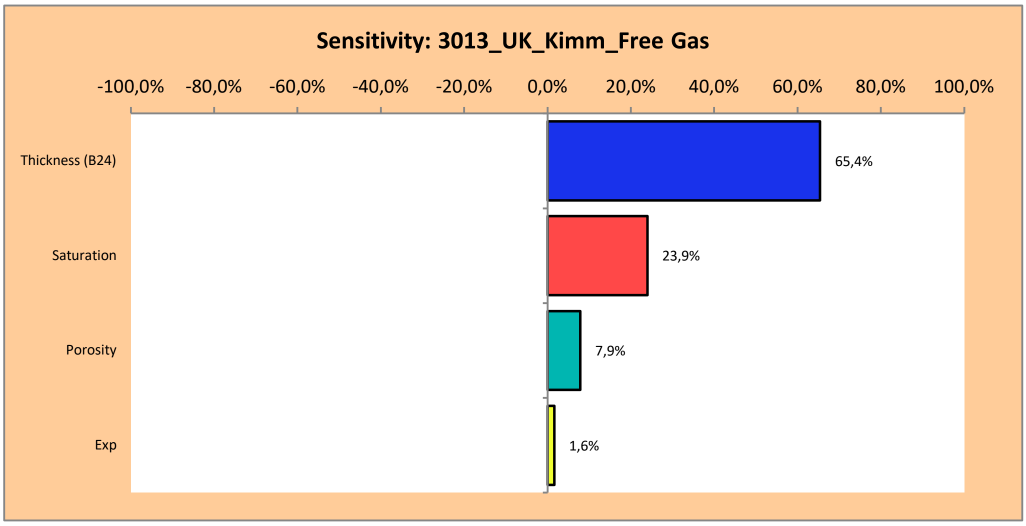
Sensitivity: 3013_UK_Kimm_100m_OIP_m3
-100,0% -80,0% -60,0% -40,0% -20,0% 0,0% 20,0% 40,0% 60,0% 80,0% 100,0%
Saturation (B31)
95,1%
Porosity (B30)
4,1%
Other
0,8%

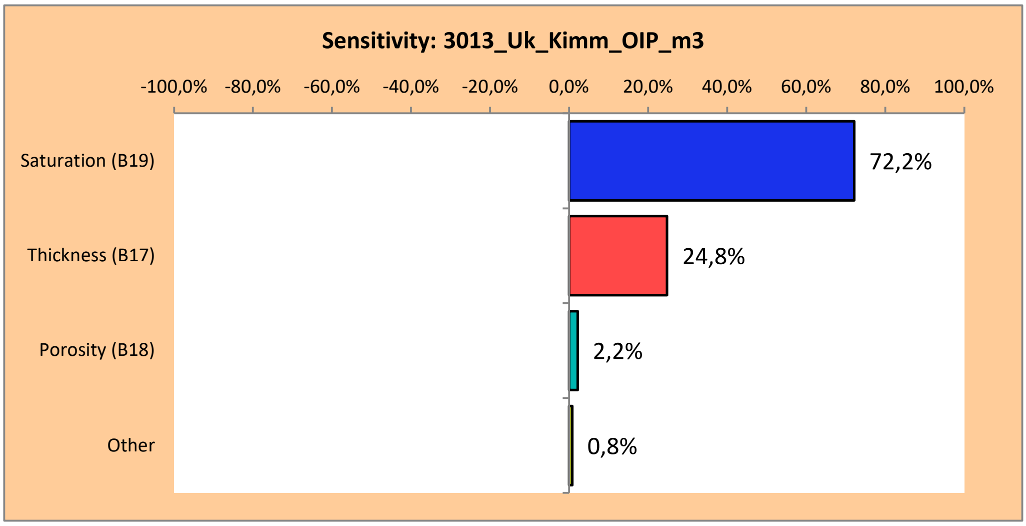


Sensitivity: 3013_UK_Kimm_Adsorbed
-100,0% -80,0% -60,0% -40,0% -20,0% 0,0% 20,0% 40,0% 60,0% 80,0% 100,0%
Thickness · 1
70,8%
Vlang · 1
27,4%


Sensitivity: 3013_UK_Kimm_Free + adsorbed
-100,0%
-80,0%
-60,0%
-40,0%
-20,0%
0,0%
20,0%
40,0%
60,0%
80,0%
100,0%
Thickness (B24)
55,3%
Saturation
21,1%
Thickness · 1
9,1%
Porosity
6,7%
Vlang · 1
4,9%


Sensitivity: 3013_UK_Kimm_Free + adsorbed
-100,0%
-80,0%
-60,0%
-40,0%
-20,0%
0,0%
20,0%
40,0%
60,0%
80,0%
100,0%
Thickness (B24)
55,3%
Saturation
21,1%
Thickness · 1
9,1%
Porosity
6,7%
Vlang · 1
4,9%
Other
2,9%



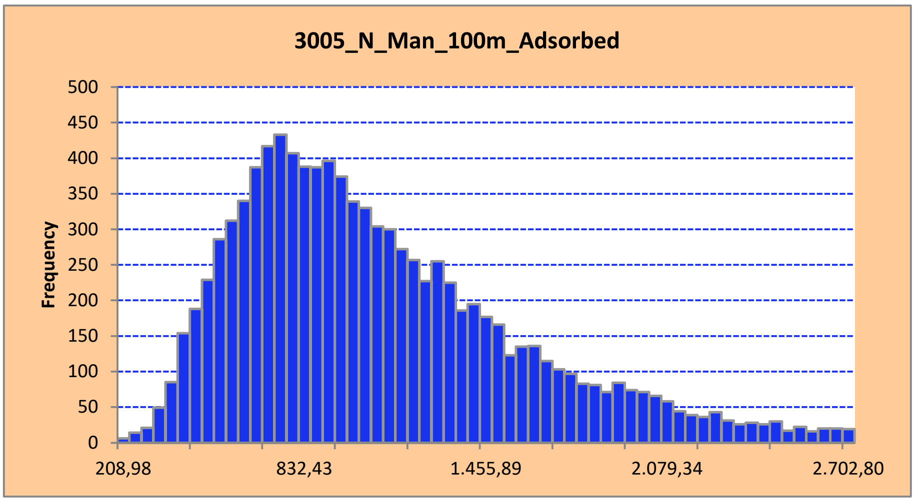


End of Sensitivity Charts

Forecasts

Forecast: 3005_N_Man_100m_Adsorbed

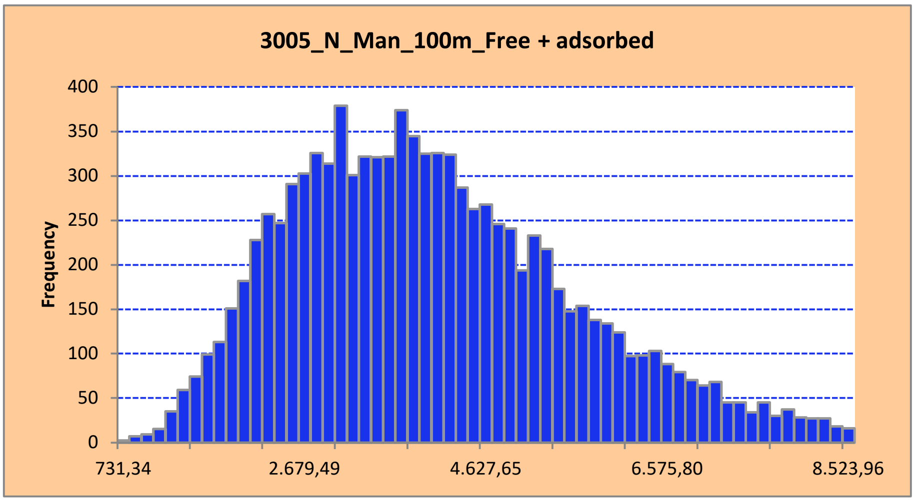
Summary:
Entire range is from 188,20 to 9.245,54
Base case is 0,03
After 10.000 trials, the std. error of the mean is 5,71



Statistics:	Forecast values
Trials	10.000
Base Case	0,03
Mean	1.124,90
Median	993,56
Mode	---
Standard Deviation	570,96
Variance	325.991,41
Skewness	1,89
Kurtosis	11,44
Coeff. of Variation	0,5076
Minimum	188,20
Maximum	9.245,54
Range Width	9.057,34
Mean Std. Error	5,71

Forecast: 3005_N_Man_100m_Free + adsorbed

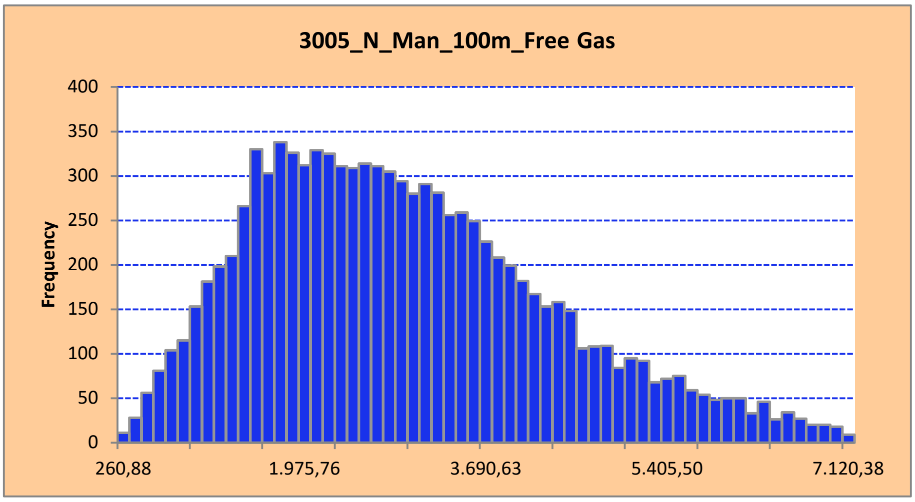
Summary:
Entire range is from 666,40 to 12.381,86
Base case is 374,65
After 10.000 trials, the std. error of the mean is 16,02



Statistics:	Forecast values
Trials	10.000
Base Case	374,65
Mean	4.103,10
Median	3.880,38
Mode	---
Standard Deviation	1.602,07
Variance	2.566.629,11
Skewness	0,7907
Kurtosis	3,73
Coeff. of Variation	0,3905
Minimum	666,40
Maximum	12.381,86
Range Width	11.715,46
Mean Std. Error	16,02

Forecast: 3005_N_Man_100m_Free Gas

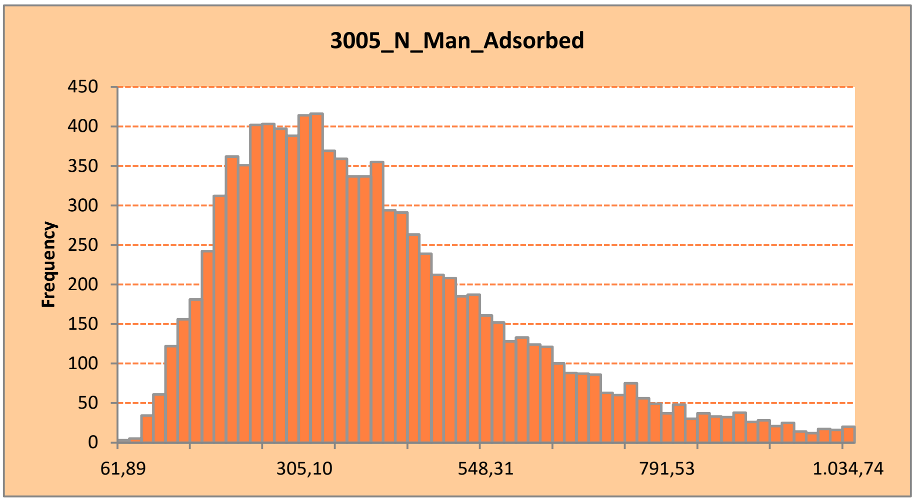
Summary:
Entire range is from 203,72 to 10.118,86
Base case is 374,61
After 10.000 trials, the std. error of the mean is 15,00



Statistics:	Forecast values
Trials	10.000
Base Case	374,61
Mean	2.978,20
Median	2.749,40
Mode	---
Standard Deviation	1.499,77
Variance	2.249.295,70
Skewness	0,8752
Kurtosis	3,88
Coeff. of Variation	0,5036
Minimum	203,72
Maximum	10.118,86
Range Width	9.915,14
Mean Std. Error	15,00

Forecast: 3005_N_Man_Adsorbed

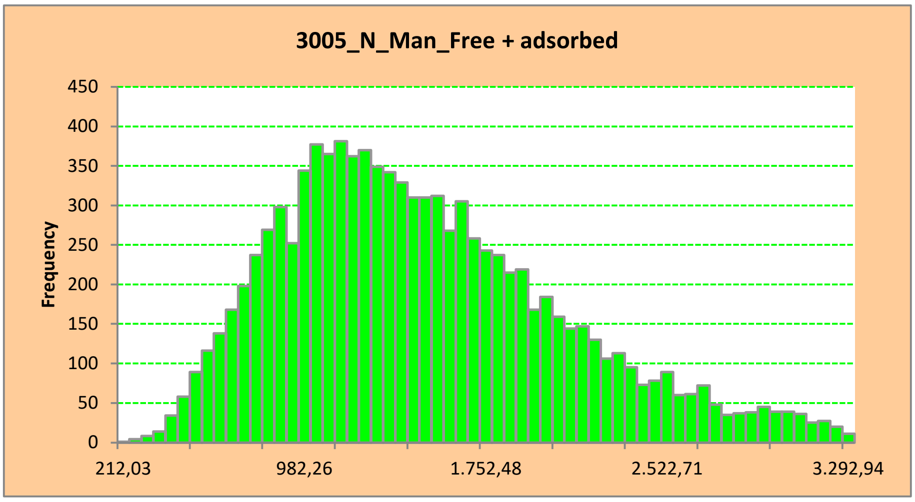
Summary:
Entire range is from 53,78 to 2.723,15
Base case is 0,03
After 10.000 trials, the std. error of the mean is 2,25



Statistics:	Forecast values
Trials	10.000
Base Case	0,03
Mean	413,23
Median	362,89
Mode	---
Standard Deviation	224,86
Variance	50.562,53
Skewness	1,95
Kurtosis	10,24
Coeff. of Variation	0,5441
Minimum	53,78
Maximum	2.723,15
Range Width	2.669,37
Mean Std. Error	2,25

Forecast: 3005_N_Man_Free + adsorbed

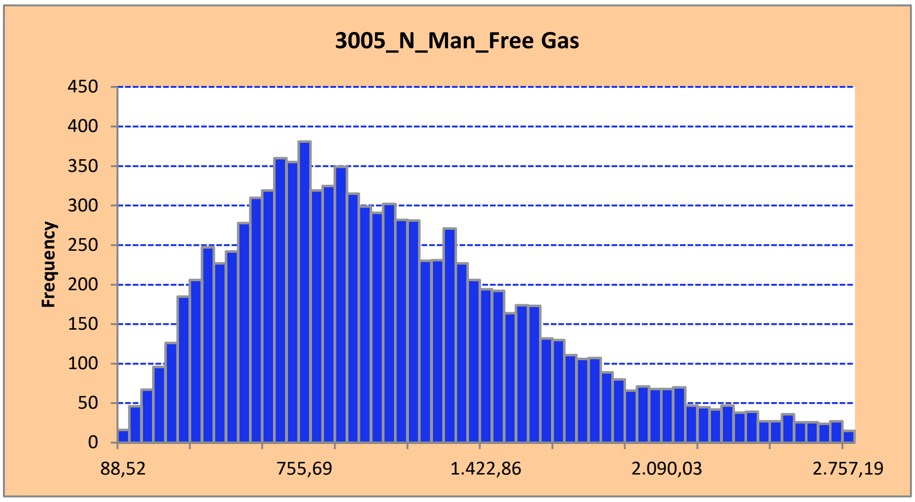
Summary:
Entire range is from 186,35 to 4.624,26
Base case is 374,65
After 10.000 trials, the std. error of the mean is 6,45



Statistics:	Forecast values
Trials	10.000
Base Case	374,65
Mean	1.512,65
Median	1.402,11
Mode	---
Standard Deviation	644,99
Variance	416.008,00
Skewness	0,9608
Kurtosis	4,13
Coeff. of Variation	0,4264
Minimum	186,35
Maximum	4.624,26
Range Width	4.437,91
Mean Std. Error	6,45

Forecast: 3005_N_Man_Free Gas

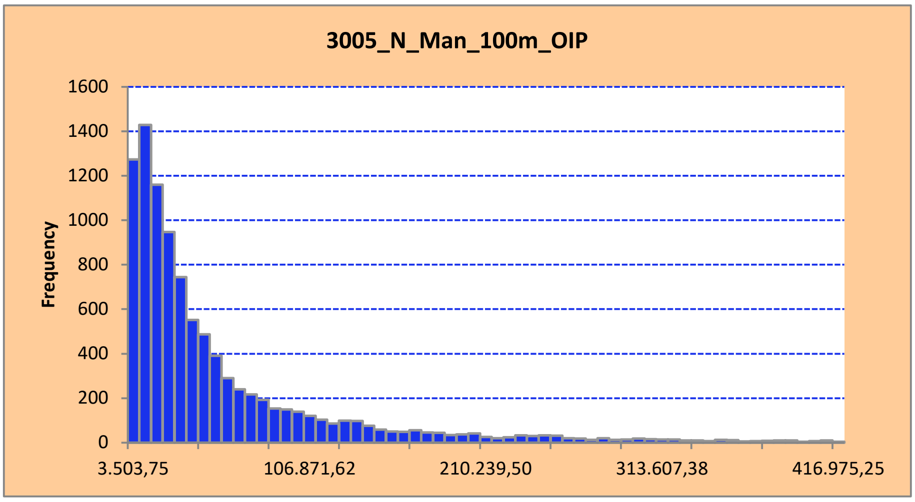
Summary:
Entire range is from 66,28 to 4.304,44
Base case is 374,61
After 10.000 trials, the std. error of the mean is 6,00



Statistics:	Forecast values
Trials	10.000
Base Case	374,61
Mean	1.099,42
Median	988,10
Mode	---
Standard Deviation	600,01
Variance	360.006,52
Skewness	1,01
Kurtosis	4,18
Coeff. of Variation	0,5457
Minimum	66,28
Maximum	4.304,44
Range Width	4.238,16
Mean Std. Error	6,00

Forecast: 3005_N_Man_100m_OIP

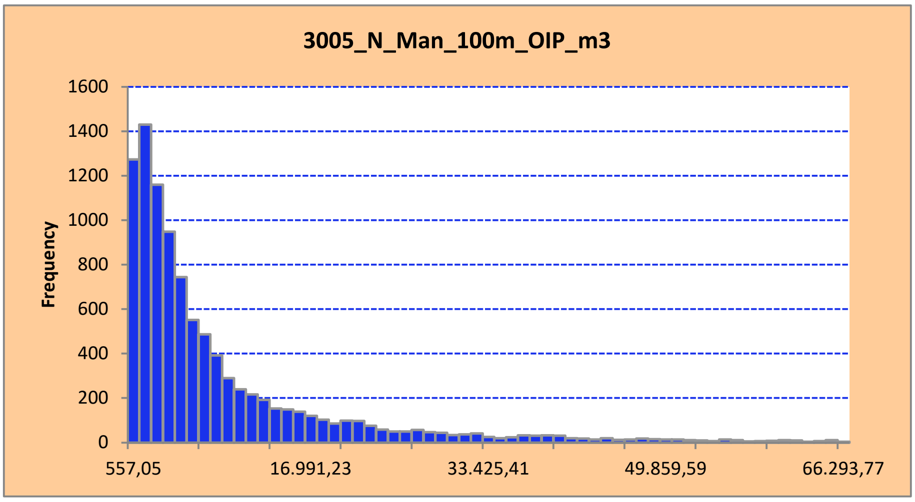
Summary:
Entire range is from 58,15 to 5.020.289,48
Base case is 11.832,77
After 10.000 trials, the std. error of the mean is 1.266,84



Statistics:	Forecast values
Trials	10.000
Base Case	11.832,77
Mean	65.705,70
Median	29.152,53
Mode	---
Standard Deviation	126.683,98
Variance	16.048.831.595,91
Skewness	10,80
Kurtosis	280,33
Coeff. of Variation	1,93
Minimum	58,15
Maximum	5.020.289,48
Range Width	5.020.231,33
Mean Std. Error	1.266,84

Forecast: 3005_N_Man_100m_OIP_m3

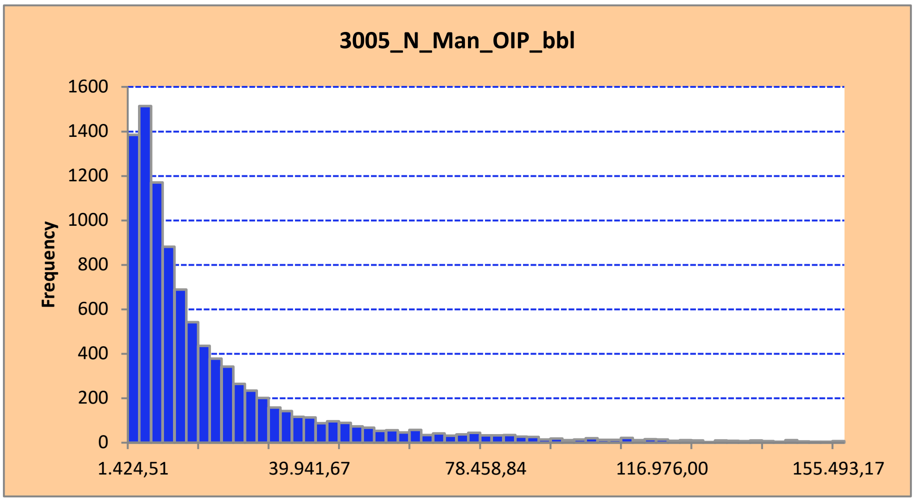
Summary:
Entire range is from 9,25 to 798.162,27
Base case is 1.881,26
After 10.000 trials, the std. error of the mean is 201,41



Statistics:	Forecast values
Trials	10.000
Base Case	1.881,26
Mean	10.446,37
Median	4.634,88
Mode	---
Standard Deviation	20.141,14
Variance	405.665.699,35
Skewness	10,80
Kurtosis	280,33
Coeff. of Variation	1,93
Minimum	9,25
Maximum	798.162,27
Range Width	798.153,03
Mean Std. Error	201,41

Forecast: 3005_N_Man_OIP_bbl

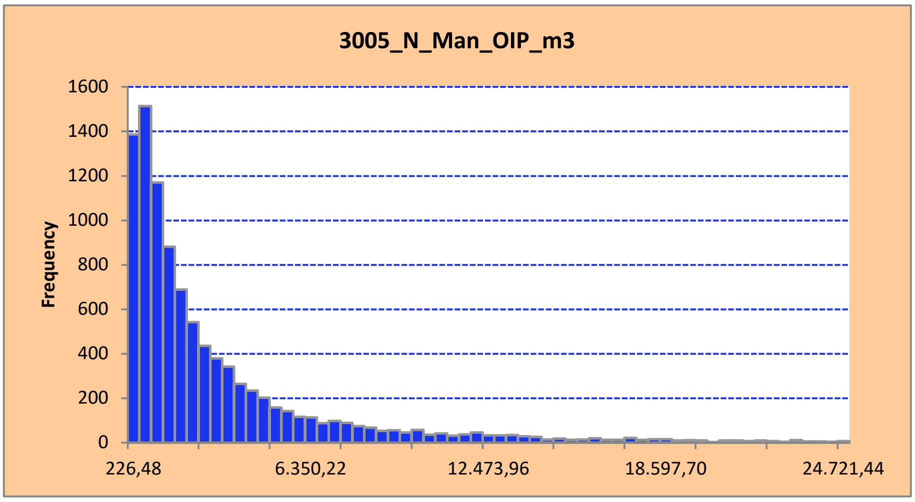
Summary:
Entire range is from 140,60 to 1.246.877,83
Base case is 11.832,77
After 10.000 trials, the std. error of the mean is 473,70



Statistics:	Forecast values
Trials	10.000
Base Case	11.832,77
Mean	24.140,54
Median	10.582,49
Mode	---
Standard Deviation	47.370,19
Variance	2.243.935.033,85
Skewness	7,92
Kurtosis	111,60
Coeff. of Variation	1,96
Minimum	140,60
Maximum	1.246.877,83
Range Width	1.246.737,23
Mean Std. Error	473,70

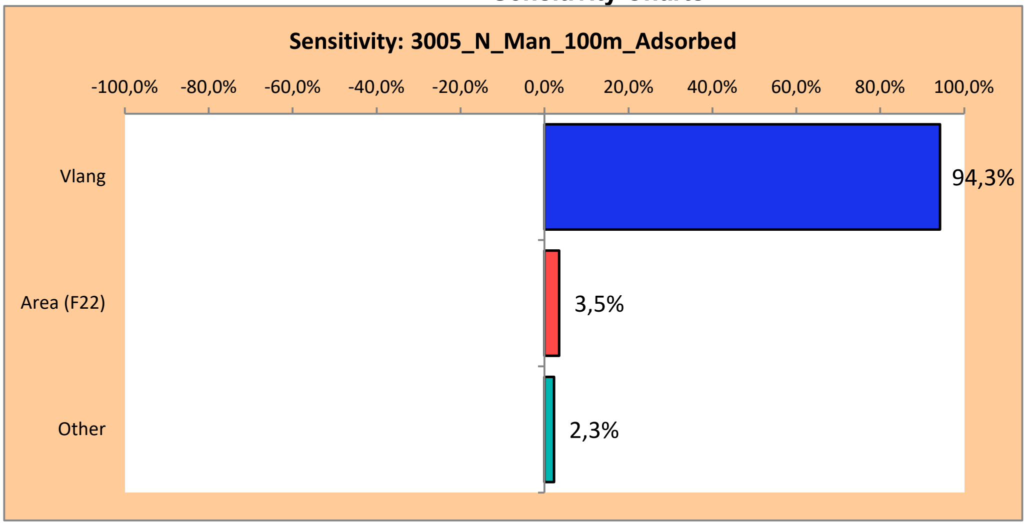
Forecast: 3005_N_Man_OIP_m3

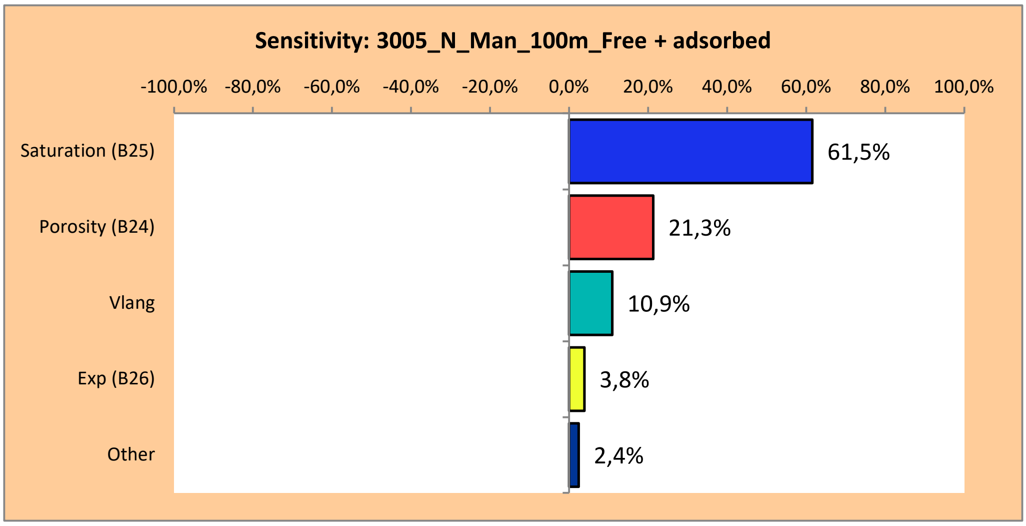
Summary:
Entire range is from 22,35 to 198.237,74
Base case is 1.881,26
After 10.000 trials, the std. error of the mean is 75,31

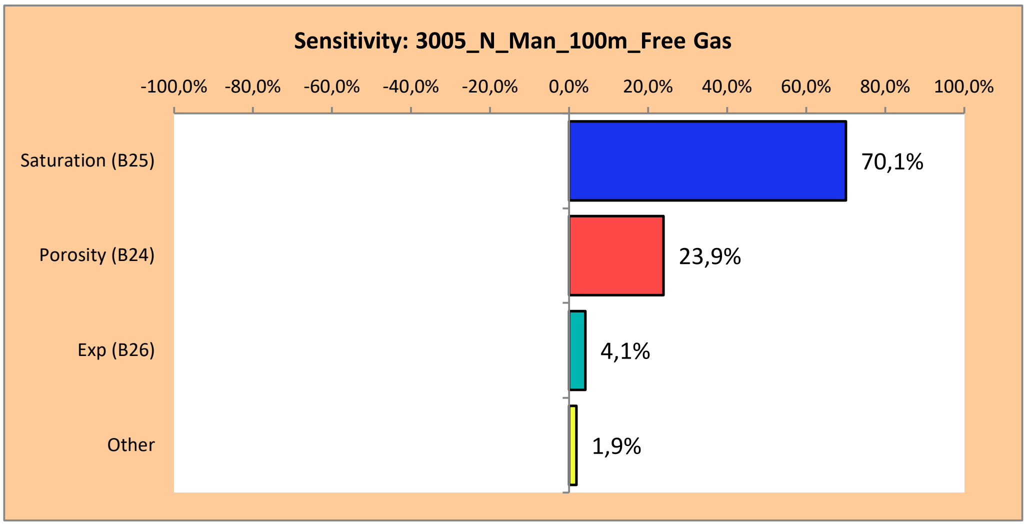


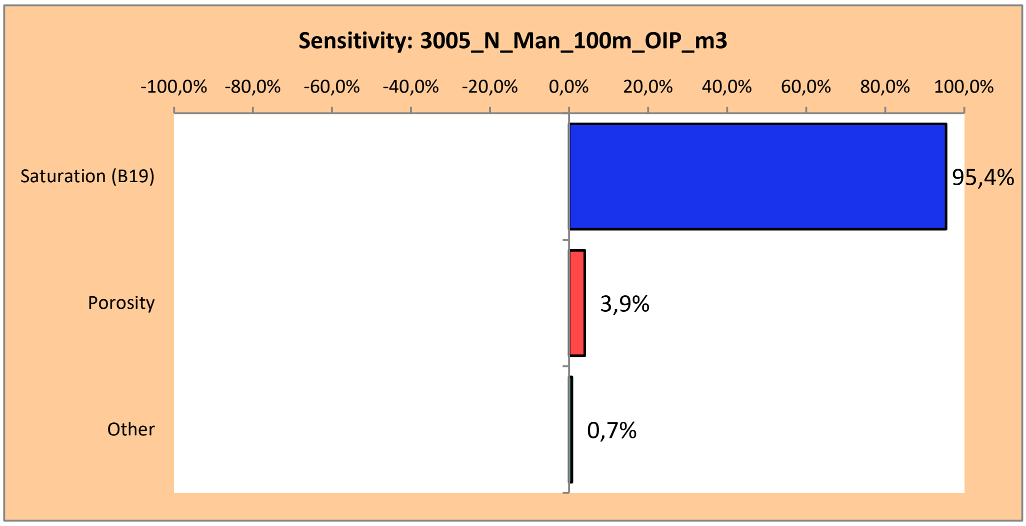
Statistics:	Forecast values
Trials	10.000
Base Case	1.881,26
Mean	3.838,04
Median	1.682,48
Mode	---
Standard Deviation	7.531,26
Variance	56.719.859,60
Skewness	7,92
Kurtosis	111,60
Coeff. of Variation	1,96
Minimum	22,35
Maximum	198.237,74
Range Width	198.215,39
Mean Std. Error	75,31

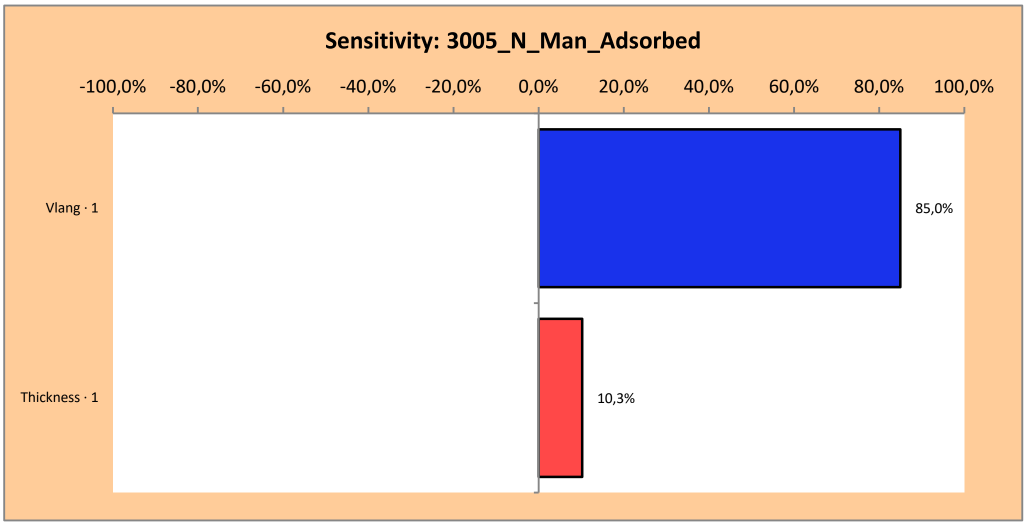
Sensitivity Charts

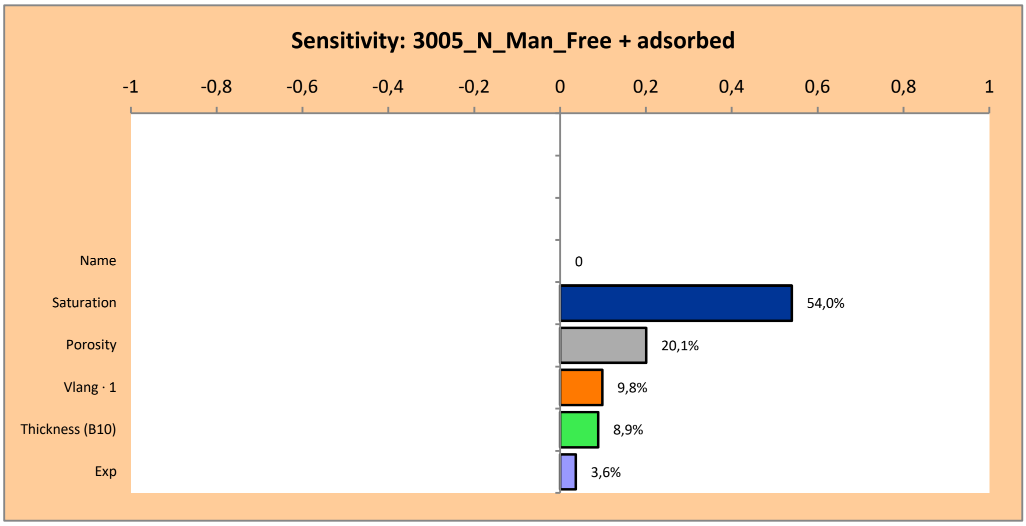


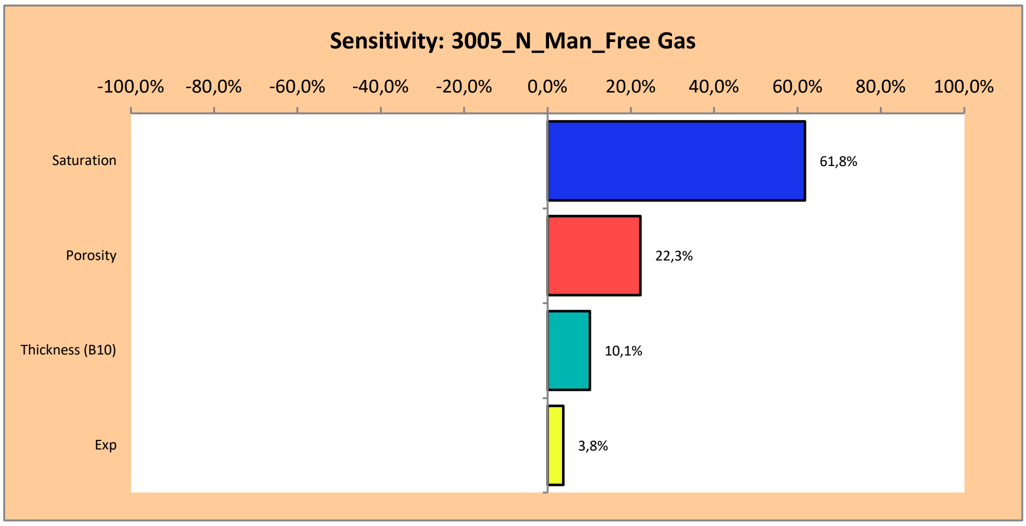


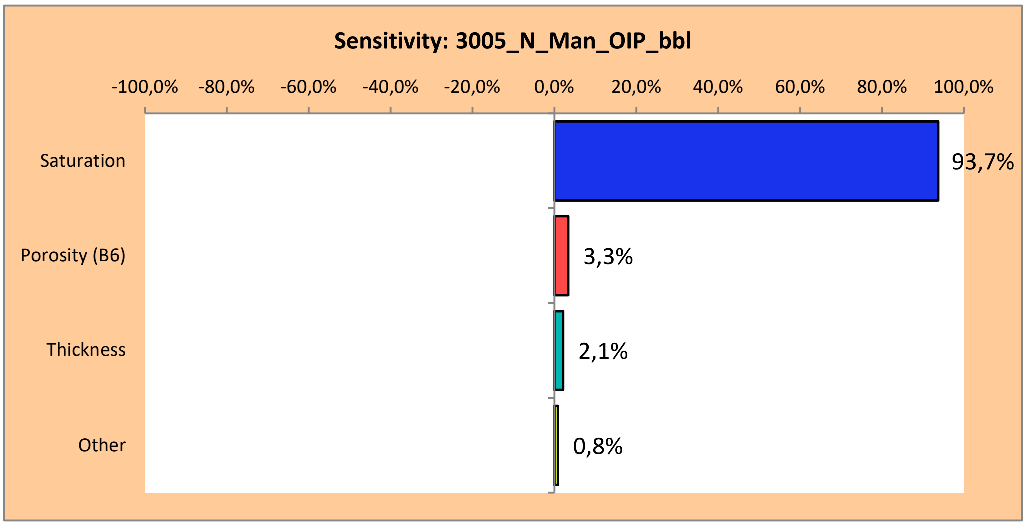

Sensitivity: 3005_N_Man_100m_Free Gas
-100,0% -80,0% -60,0% -40,0% -20,0% 0,0% 20,0% 40,0% 60,0% 80,0% 100,0%
Saturation (B25)
70,1%
Porosity (B24)
23,9%
Exp (B26)
4,1%
Other
1,9%


Sensitivity: 3005_N_Man_100m_OIP_m3
-100,0% -80,0% -60,0% -40,0% -20,0% 0,0% 20,0% 40,0% 60,0% 80,0% 100,0%
Saturation (B19)
95,4%
Porosity
3,9%
Other
0,7%


Sensitivity: 3005_N_Man_Adsorbed
-100,0%
-80,0%
-60,0%
-40,0%
-20,0%
0,0%
20,0%
40,0%
60,0%
80,0%
100,0%
Vlang · 1
Thickness · 1
85,0%
10,3%


Sensitivity: 3005_N_Man_Free + adsorbed
-1
-0,8
-0,6
-0,4
-0,2
0
0,2
0,4
0,6
0,8
1
Name
Saturation
Porosity
Vlang · 1
Thickness (B10)
Exp
0
54,0%
20,1%
9,8%
8,9%
3,6%



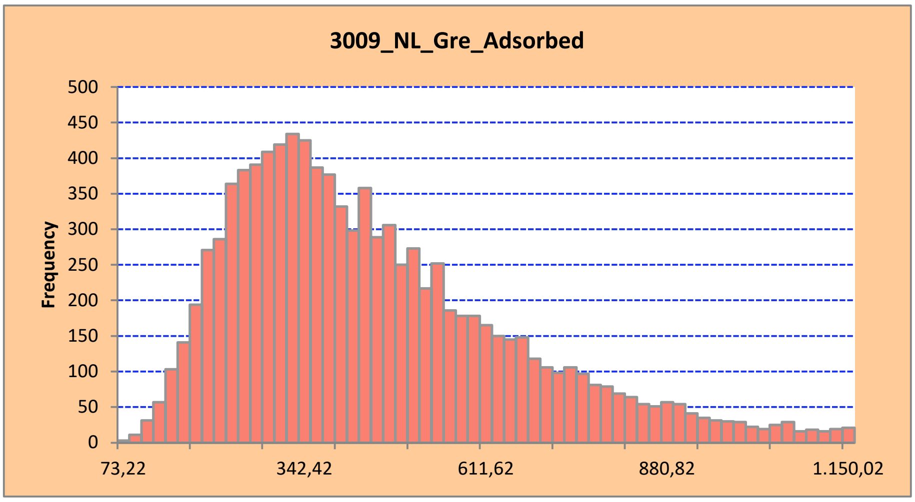


End of Sensitivity Charts

Forecasts

Forecast: 3009_NL_Gre_Adsorbed

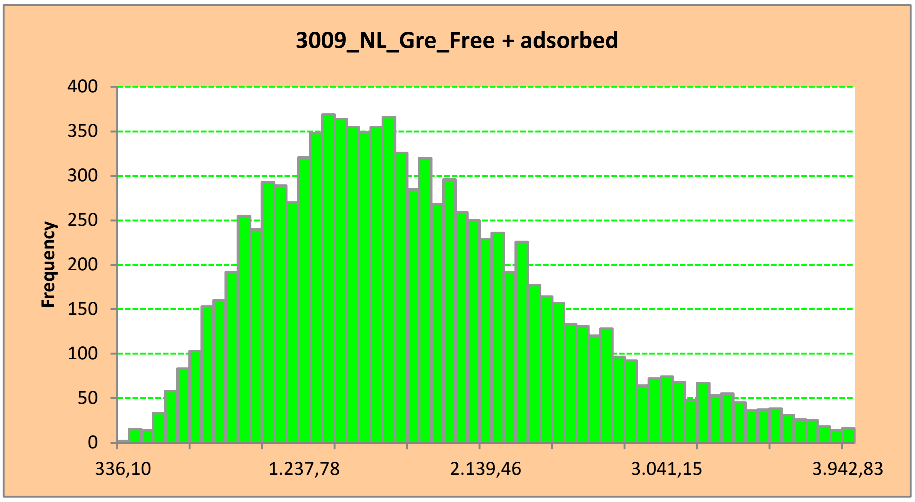
Summary:
- Certainty level is 0,00%
- Certainty range is from ∞ to ∞
- Entire range is from 64,25 to 2.689,97
- Base case is 0,03
- After 10.000 trials, the std. error of the mean is 2,48



Statistics:	Forecast values
Trials	10.000
Base Case	0,03
Mean	463,57
Median	404,45
Mode	---
Standard Deviation	248,37
Variance	61.685,43
Skewness	1,76
Kurtosis	8,39
Coeff. of Variation	0,5358
Minimum	64,25
Maximum	2.689,97
Range Width	2.625,72
Mean Std. Error	2,48

Forecast: 3009_NL_Gre_Free + adsorbed

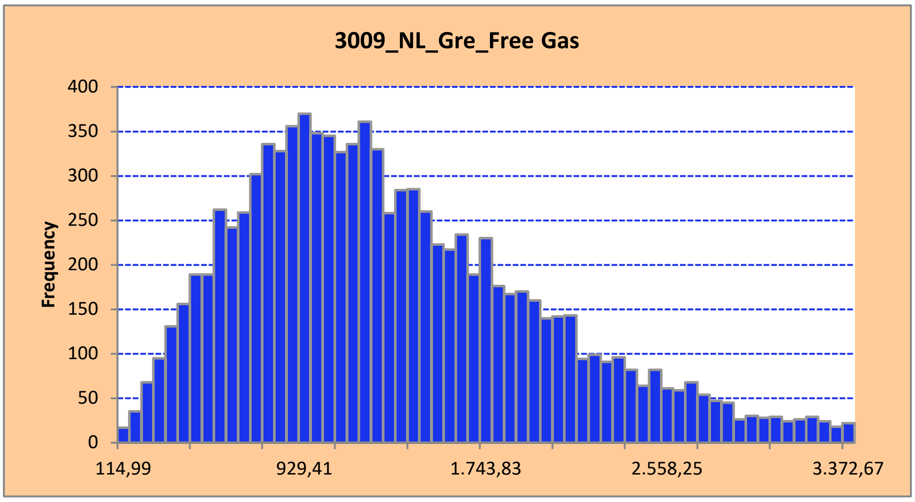
Summary:
Entire range is from 306,05 to 5.989,91
Base case is 374,65
After 10.000 trials, the std. error of the mean is 7,68



Statistics:	Forecast values
Trials	10.000
Base Case	374,65
Mean	1.821,78
Median	1.691,58
Mode	---
Standard Deviation	768,25
Variance	590.208,81
Skewness	0,9822
Kurtosis	4,34
Coeff. of Variation	0,4217
Minimum	306,05
Maximum	5.989,91
Range Width	5.683,86
Mean Std. Error	7,68

Forecast: 3009_NL_Gre_Free Gas

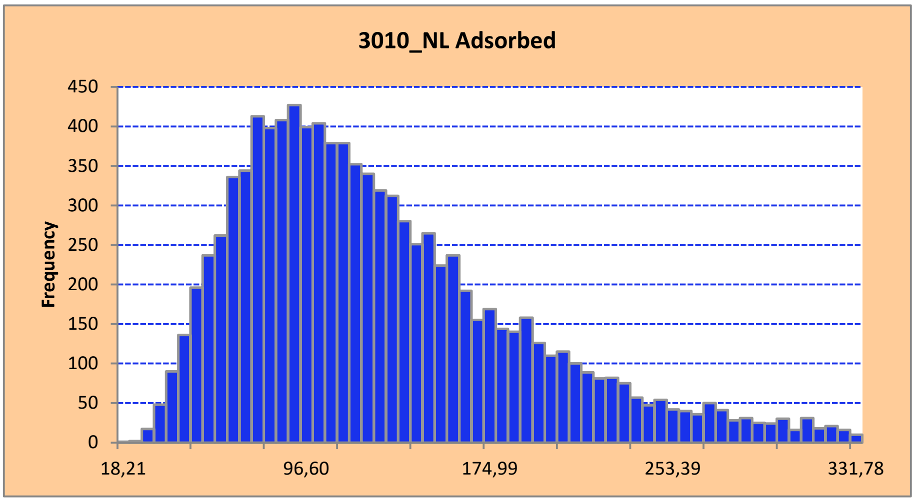
Summary:
Entire range is from 87,85 to 5.672,77
Base case is 374,61
After 10.000 trials, the std. error of the mean is 7,29



Statistics:	Forecast values
Trials	10.000
Base Case	374,61
Mean	1.358,21
Median	1.220,34
Mode	---
Standard Deviation	729,15
Variance	531.654,84
Skewness	1,06
Kurtosis	4,51
Coeff. of Variation	0,5368
Minimum	87,85
Maximum	5.672,77
Range Width	5.584,92
Mean Std. Error	7,29

Forecast: 3010_NL Adsorbed

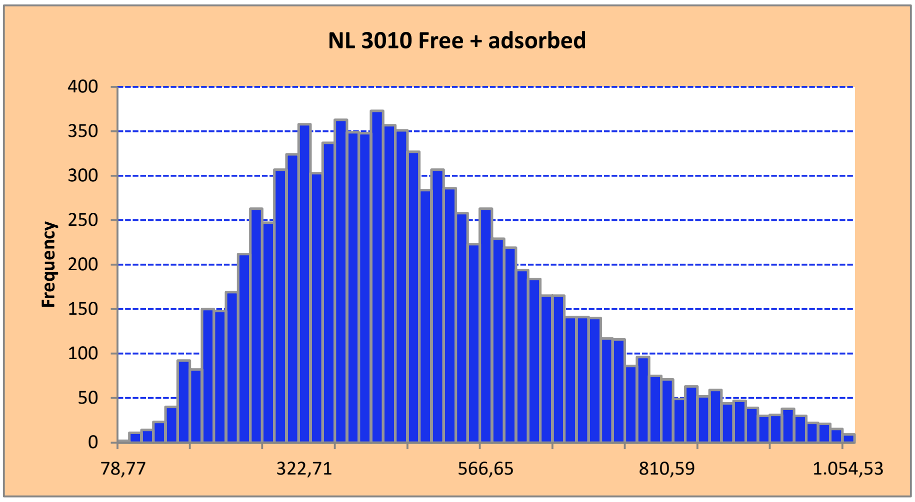
Summary:
Entire range is from 15,59 to 777,64
Base case is 0,03
After 10.000 trials, the std. error of the mean is 0,72



Statistics:	Forecast values
Trials	10.000
Base Case	0,03
Mean	133,13
Median	116,95
Mode	---
Standard Deviation	71,88
Variance	5.166,46
Skewness	1,90
Kurtosis	9,78
Coeff. of Variation	0,5399
Minimum	15,59
Maximum	777,64
Range Width	762,05
Mean Std. Error	0,72

Forecast: NL 3010 Free + adsorbed

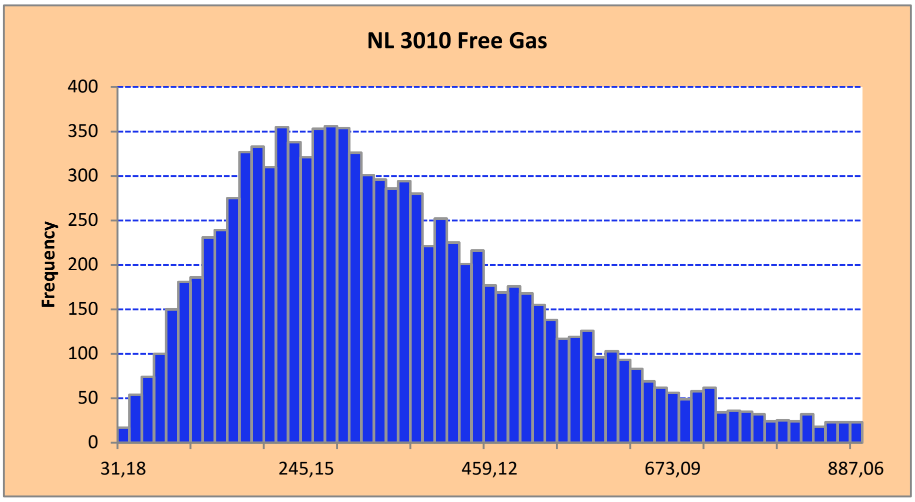
Summary:
Entire range is from 70,64 to 1.690,40
Base case is 374,65
After 10.000 trials, the std. error of the mean is 2,06



Statistics:	Forecast values
Trials	10.000
Base Case	374,65
Mean	484,81
Median	450,65
Mode	---
Standard Deviation	206,38
Variance	42.591,43
Skewness	1,00
Kurtosis	4,50
Coeff. of Variation	0,4257
Minimum	70,64
Maximum	1.690,40
Range Width	1.619,76
Mean Std. Error	2,06

Forecast: NL 3010 Free Gas

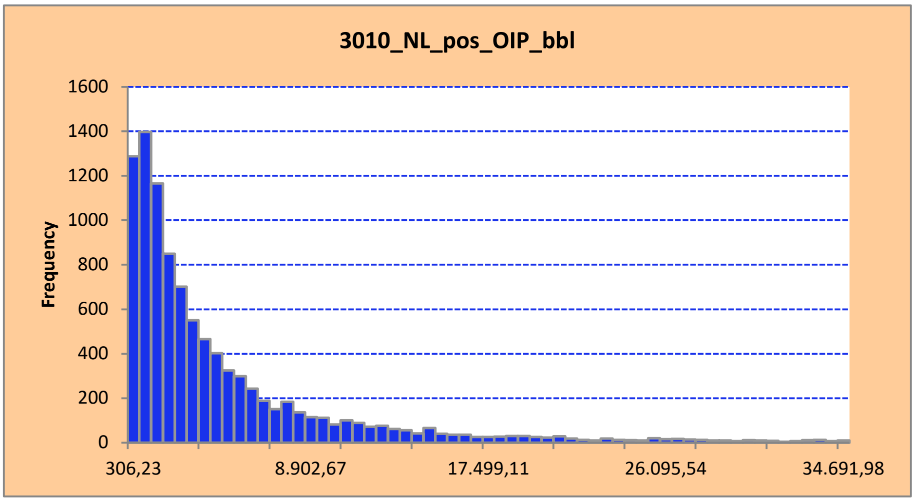
Summary:
Entire range is from 24,05 to 1.588,22
Base case is 374,61
After 10.000 trials, the std. error of the mean is 1,94



Statistics:	Forecast values
Trials	10.000
Base Case	374,61
Mean	351,68
Median	314,80
Mode	---
Standard Deviation	193,75
Variance	37.540,86
Skewness	1,13
Kurtosis	4,89
Coeff. of Variation	0,5509
Minimum	24,05
Maximum	1.588,22
Range Width	1.564,17
Mean Std. Error	1,94

Forecast: 3010_NL_pos_OIP_bbl

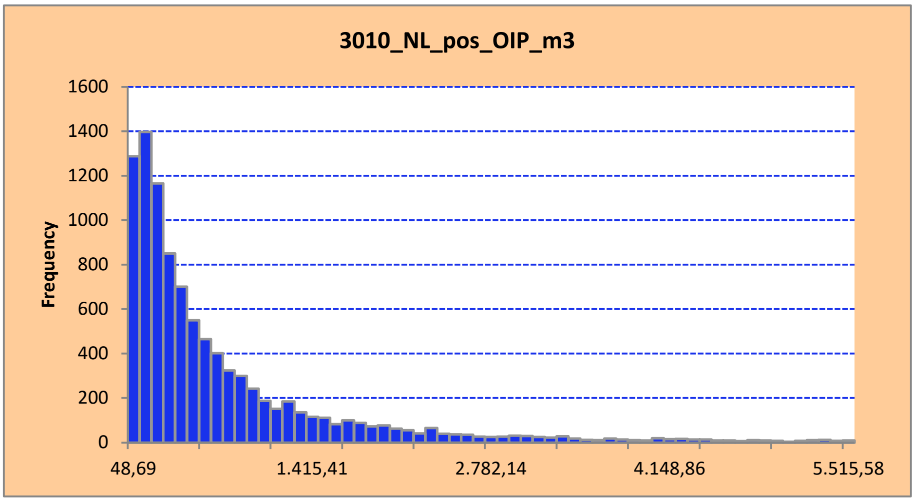
Summary:
Entire range is from 19,68 to 274.934,33
Base case is 1.227,62
After 10.000 trials, the std. error of the mean is 104,89



Statistics:	Forecast values
Trials	10.000
Base Case	1.227,62
Mean	5.609,73
Median	2.542,53
Mode	---
Standard Deviation	10.488,86
Variance	110.016.123,81
Skewness	8,15
Kurtosis	129,92
Coeff. of Variation	1,87
Minimum	19,68
Maximum	274.934,33
Range Width	274.914,65
Mean Std. Error	104,89

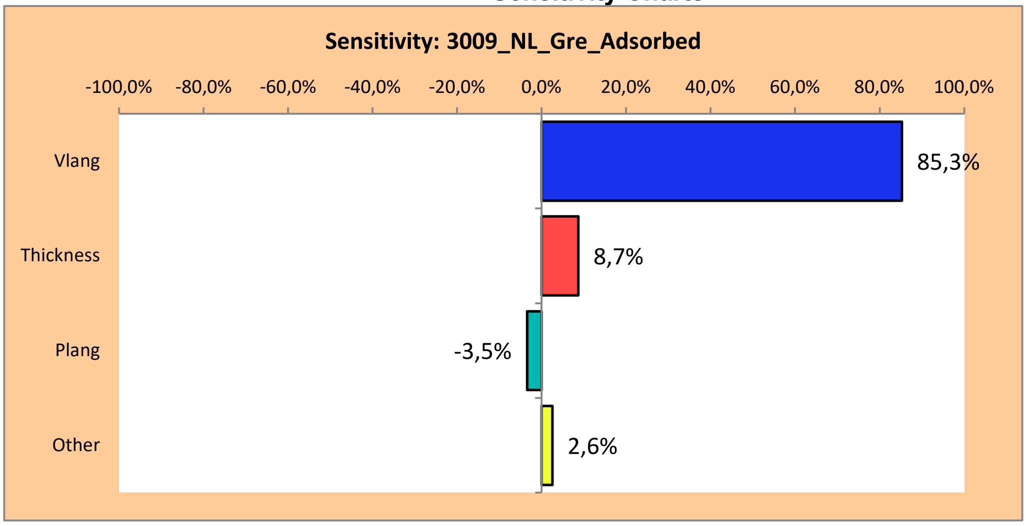
Forecast: 3010_NL_pos_OIP_m3

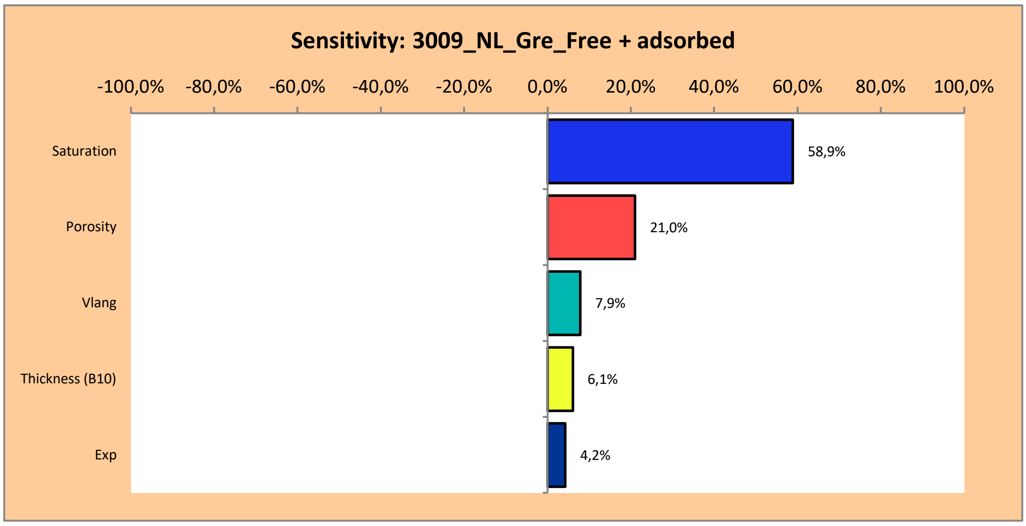
Summary:
Entire range is from 3,13 to 43.711,07
Base case is 195,18
After 10.000 trials, the std. error of the mean is 16,68

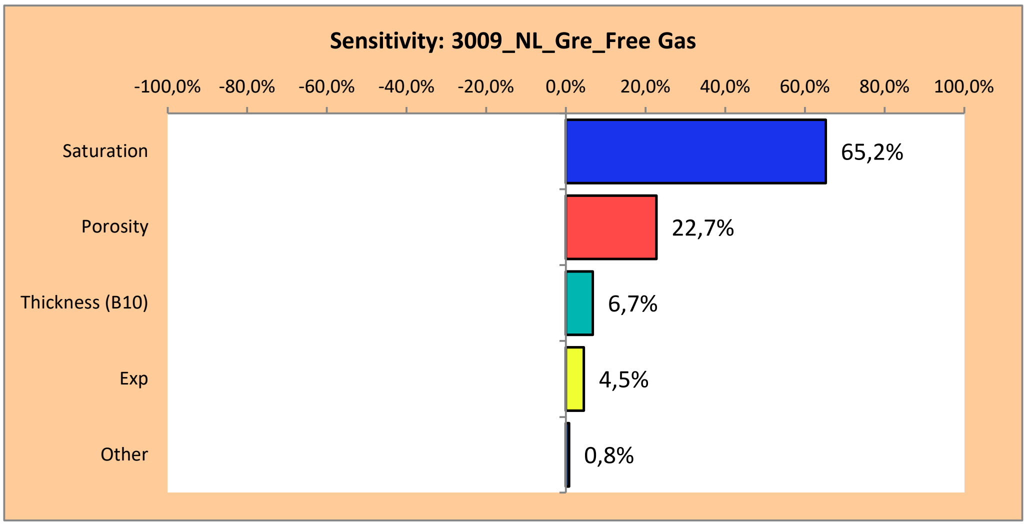


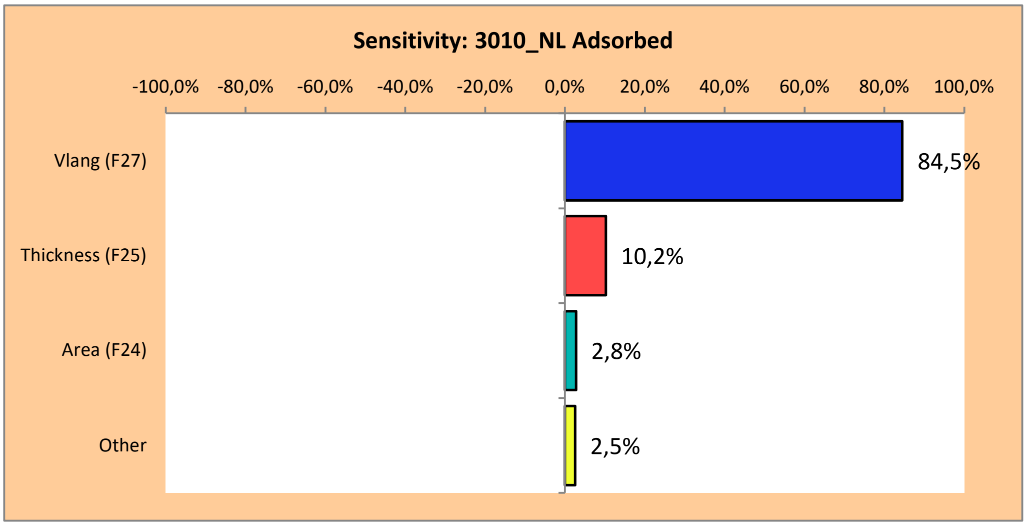
Statistics:	Forecast values
Trials	10.000
Base Case	195,18
Mean	891,88
Median	404,23
Mode	---
Standard Deviation	1.667,60
Variance	2.780.873,33
Skewness	8,15
Kurtosis	129,92
Coeff. of Variation	1,87
Minimum	3,13
Maximum	43.711,07
Range Width	43.707,94
Mean Std. Error	16,68

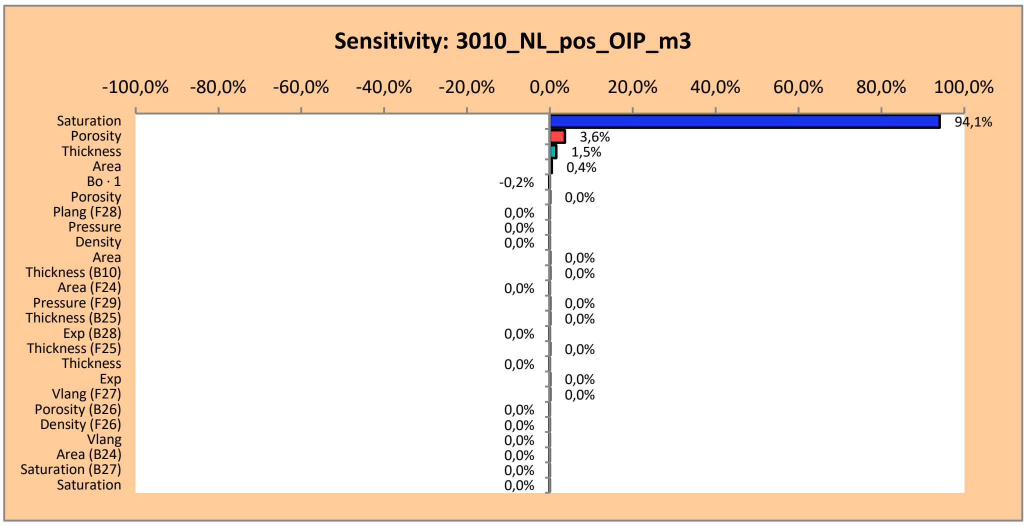
Sensitivity Charts

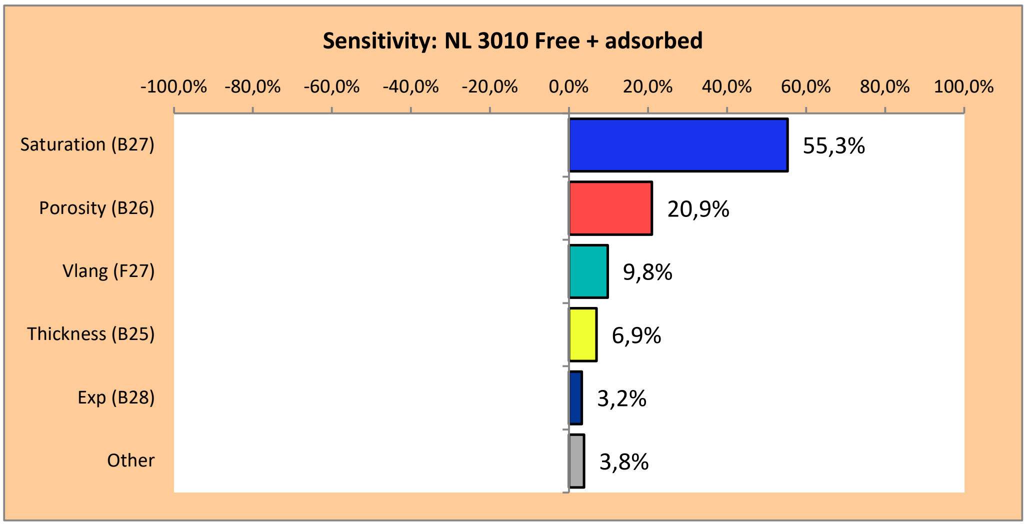


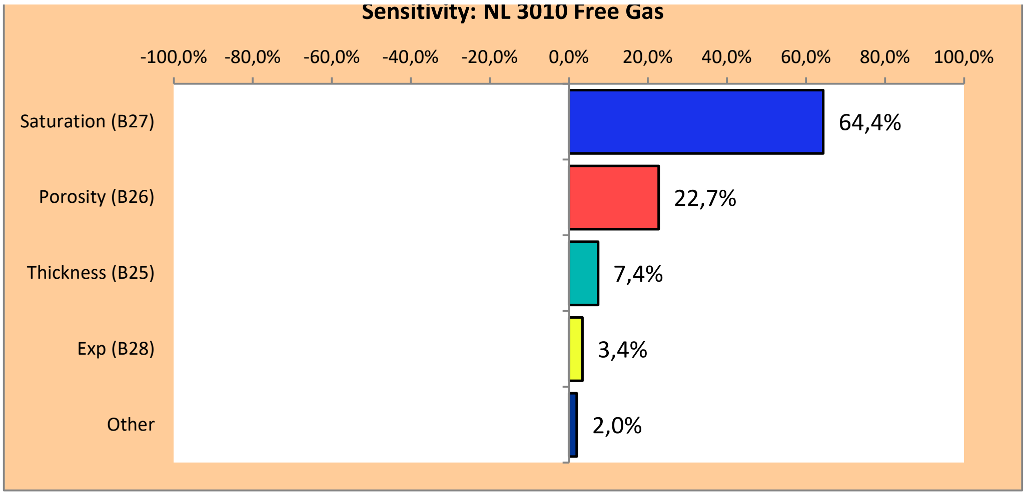


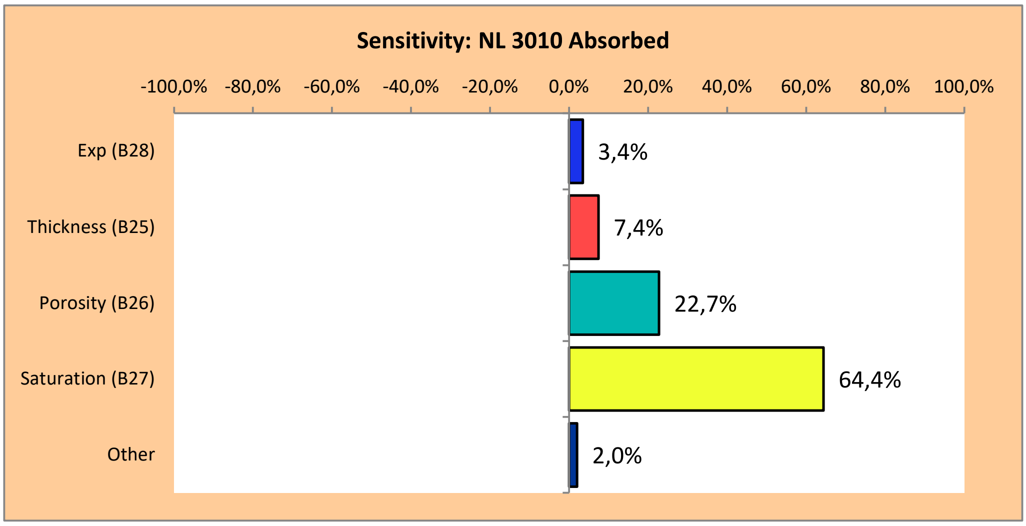

Sensitivity: 3009_NL_Gre_Free Gas
-100,0% -80,0% -60,0% -40,0% -20,0% 0,0% 20,0% 40,0% 60,0% 80,0% 100,0%
Saturation
65,2%
Porosity
22,7%
Thickness (B10)
6,7%
Exp
4,5%
Other
0,8%


Sensitivity: 3010_NL Adsorbed
-100,0% -80,0% -60,0% -40,0% -20,0% 0,0% 20,0% 40,0% 60,0% 80,0% 100,0%
Vlang (F27)
84,5%
Thickness (F25)
10,2%
Area (F24)
2,8%
Other
2,5%


Sensitivity: 3010_NL_pos_OIP_m3
-100,0%
-80,0%
-60,0%
-40,0%
-20,0%
0,0%
20,0%
40,0%
60,0%
80,0%
100,0%
Saturation 94,1%
Porosity 3,6%
Thickness 1,5%
Area 0,4%
Bo · 1 -0,2%
Porosity 0,0%
Plang (F28) 0,0%
Pressure 0,0%
Density 0,0%
Area 0,0%
Thickness (B10) 0,0%
Area (F24) 0,0%
Pressure (F29) 0,0%
Thickness (B25) 0,0%
Exp (B28) 0,0%
Thickness (F25) 0,0%
Thickness 0,0%
Exp 0,0%
Vlang (F27) 0,0%
Porosity (B26) 0,0%
Density (F26) 0,0%
Vlang 0,0%
Area (B24) 0,0%
Saturation (B27) 0,0%
Saturation 0,0%


Sensitivity: NL 3010 Free + adsorbed
-100,0%
-80,0%
-60,0%
-40,0%
-20,0%
0,0%
20,0%
40,0%
60,0%
80,0%
100,0%
Saturation (B27) 55,3%
Porosity (B26) 20,9%
Vlang (F27) 9,8%
Thickness (B25) 6,9%
Exp (B28) 3,2%
Other 3,8%


Sensitivity: NL 3010 Free Gas
-100,0% -80,0% -60,0% -40,0% -20,0% 0,0% 20,0% 40,0% 60,0% 80,0% 100,0%
Saturation (B27)
64,4%
Porosity (B26)
22,7%
Thickness (B25)
7,4%
Exp (B28)
3,4%
Other
2,0%


Sensitivity: NL 3010 Absorbed
-100,0% -80,0% -60,0% -40,0% -20,0% 0,0% 20,0% 40,0% 60,0% 80,0% 100,0%
Exp (B28)
3,4%
Thickness (B25)
7,4%
Porosity (B26)
22,7%
Saturation (B27)
64,4%
Other
2,0%

11 APPENDIX D. PLAY MAPS

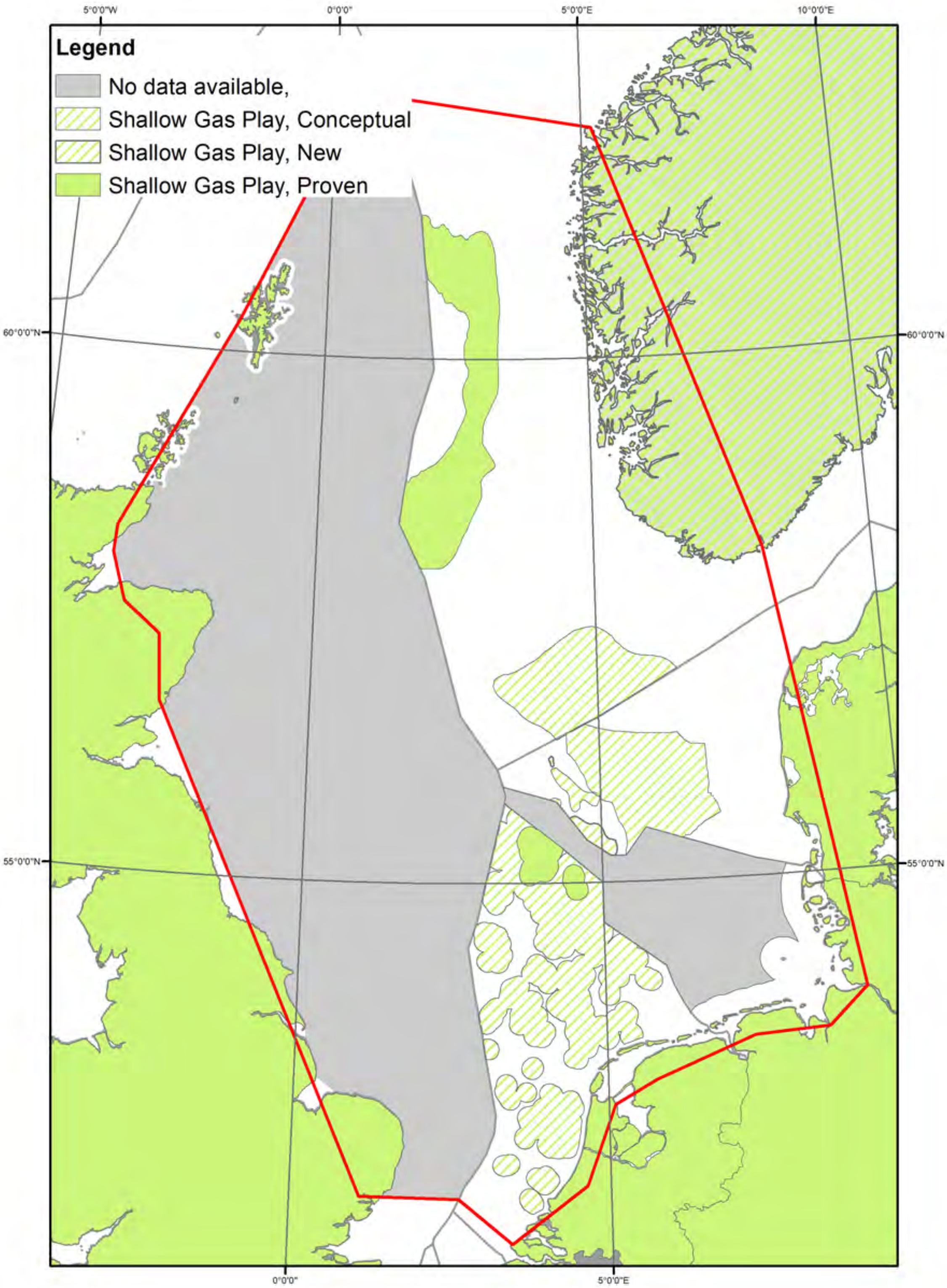


Figure 11-1 Combined cross-border play map for shallow gas play.

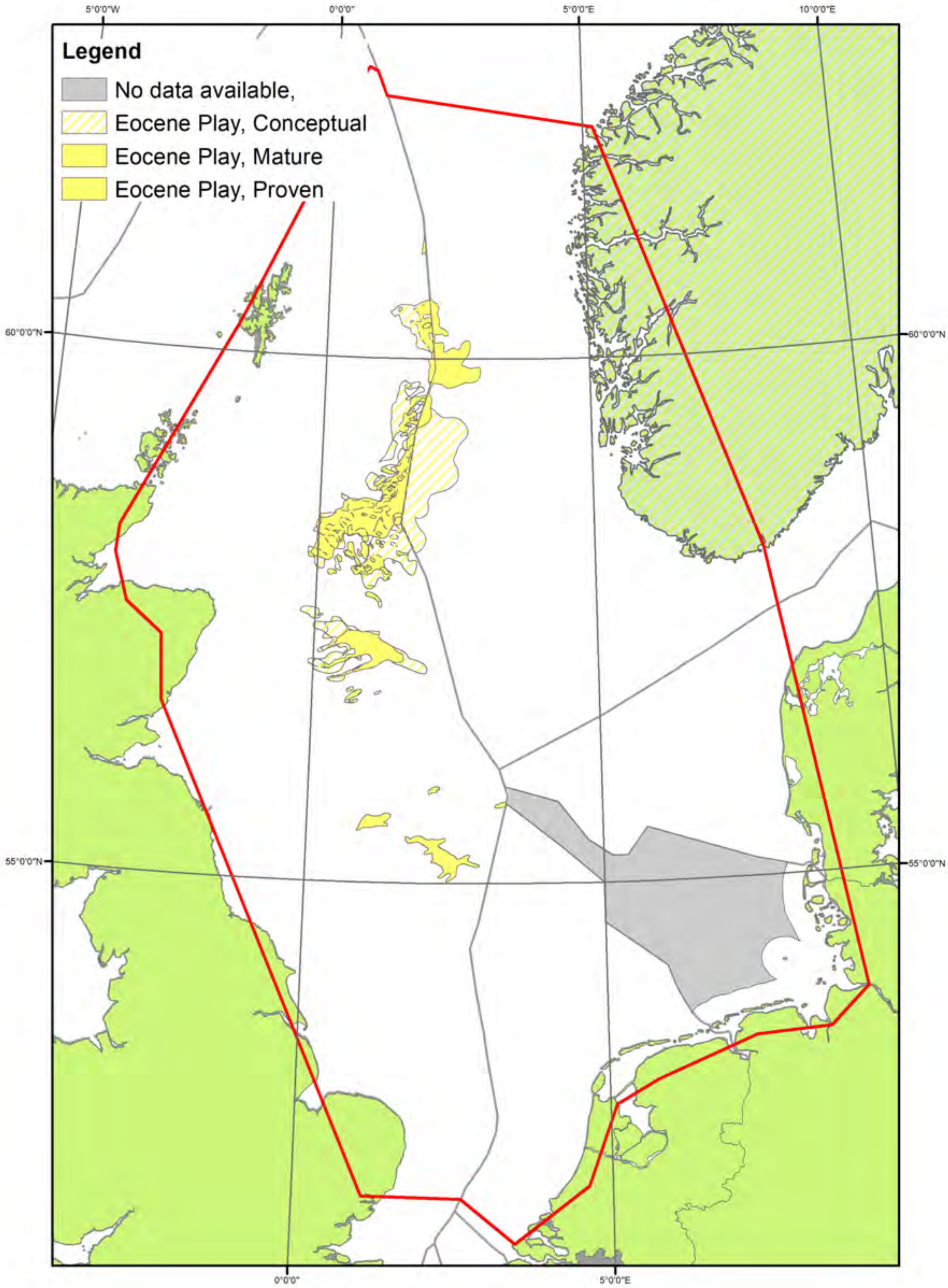


Figure 11-2 Combined cross-border play map for Eocene play.

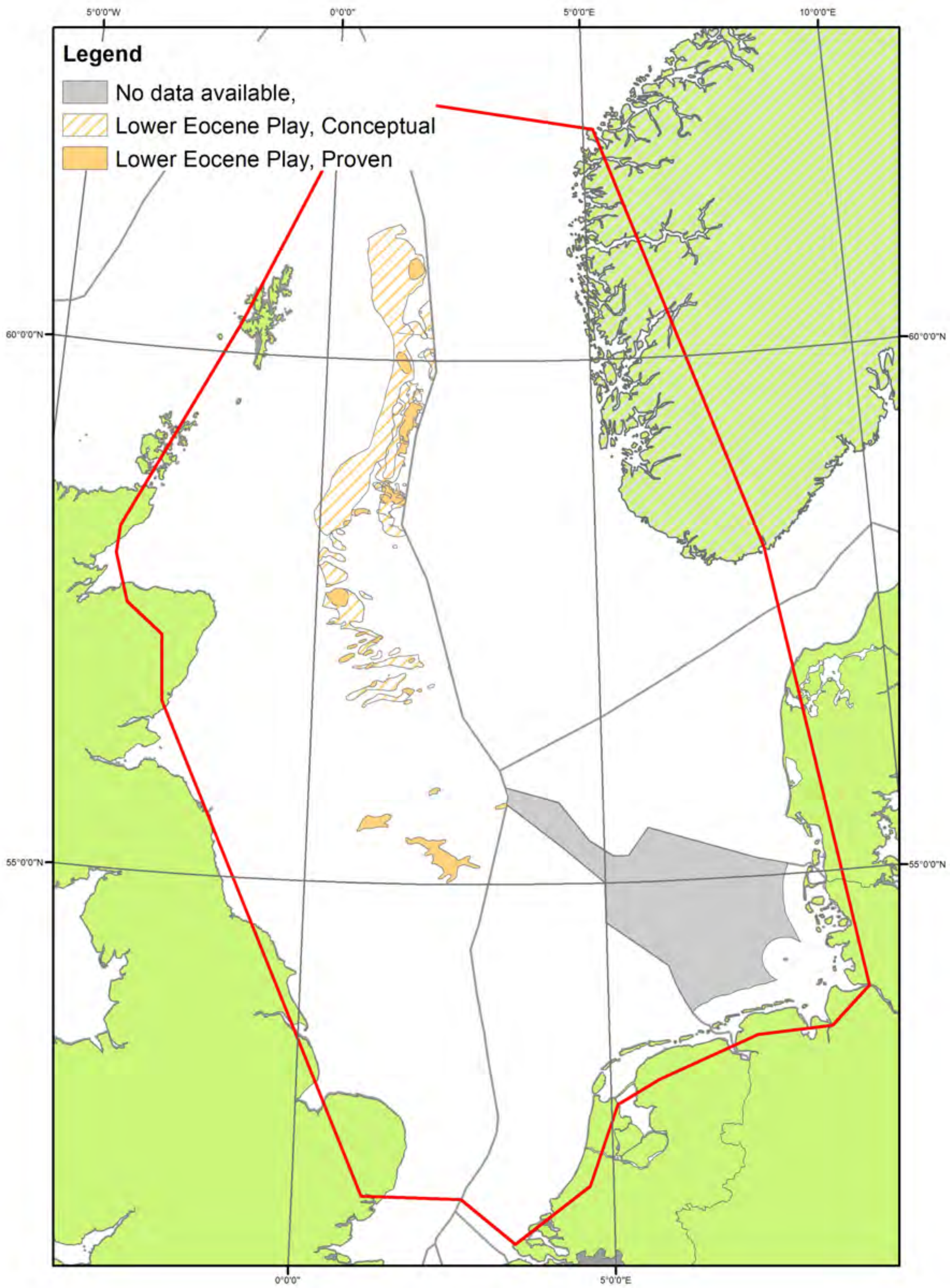


Figure 11-3 Combined cross-border play map for Lower Eocene play.

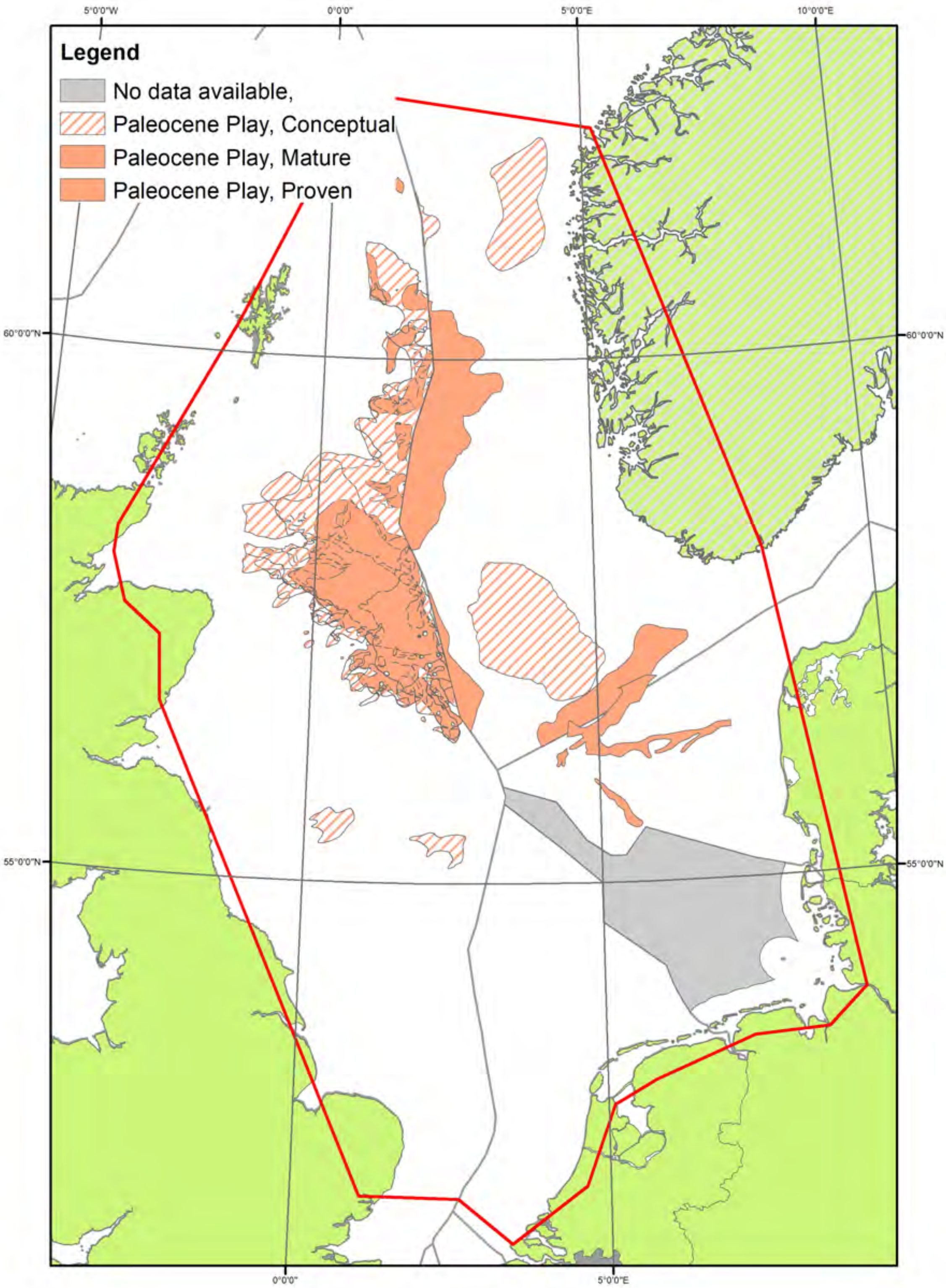


Figure 11-4 Combined cross-border play map for Paleocene play.

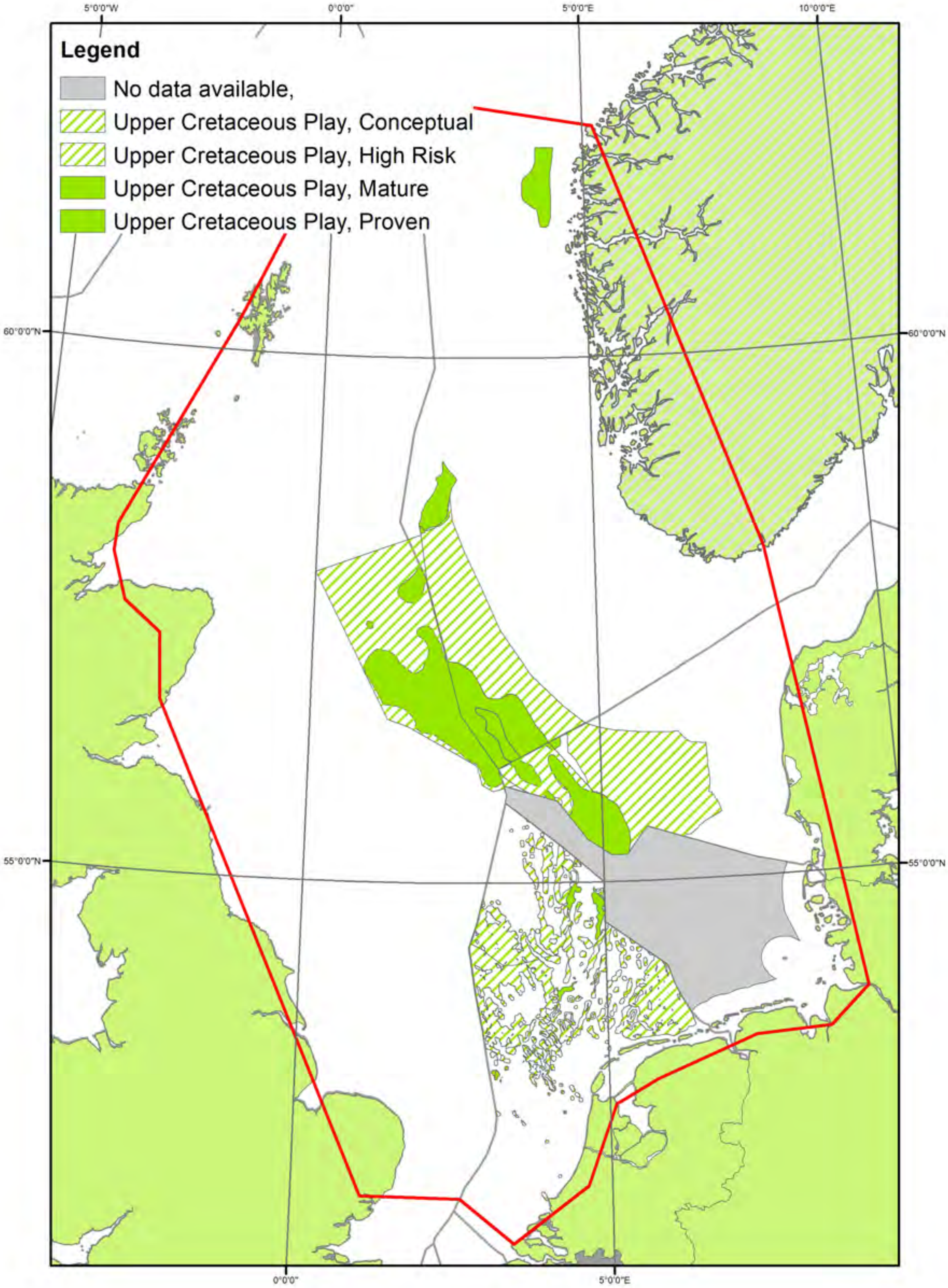


Figure 11-5 Combined cross-border play map for Upper Cretaceous play.

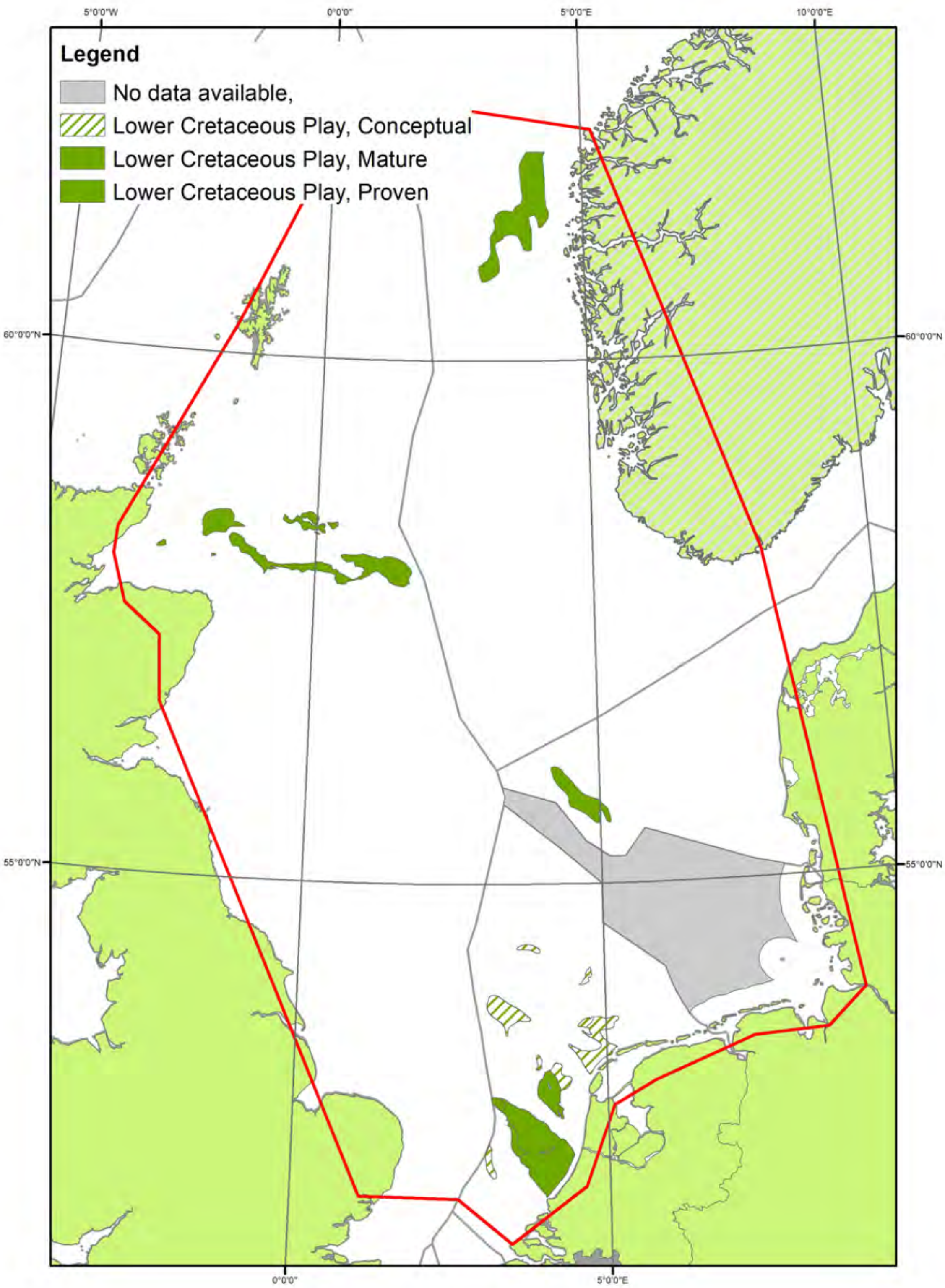


Figure 11-6 Combined cross-border play map for Lower Cretaceous play

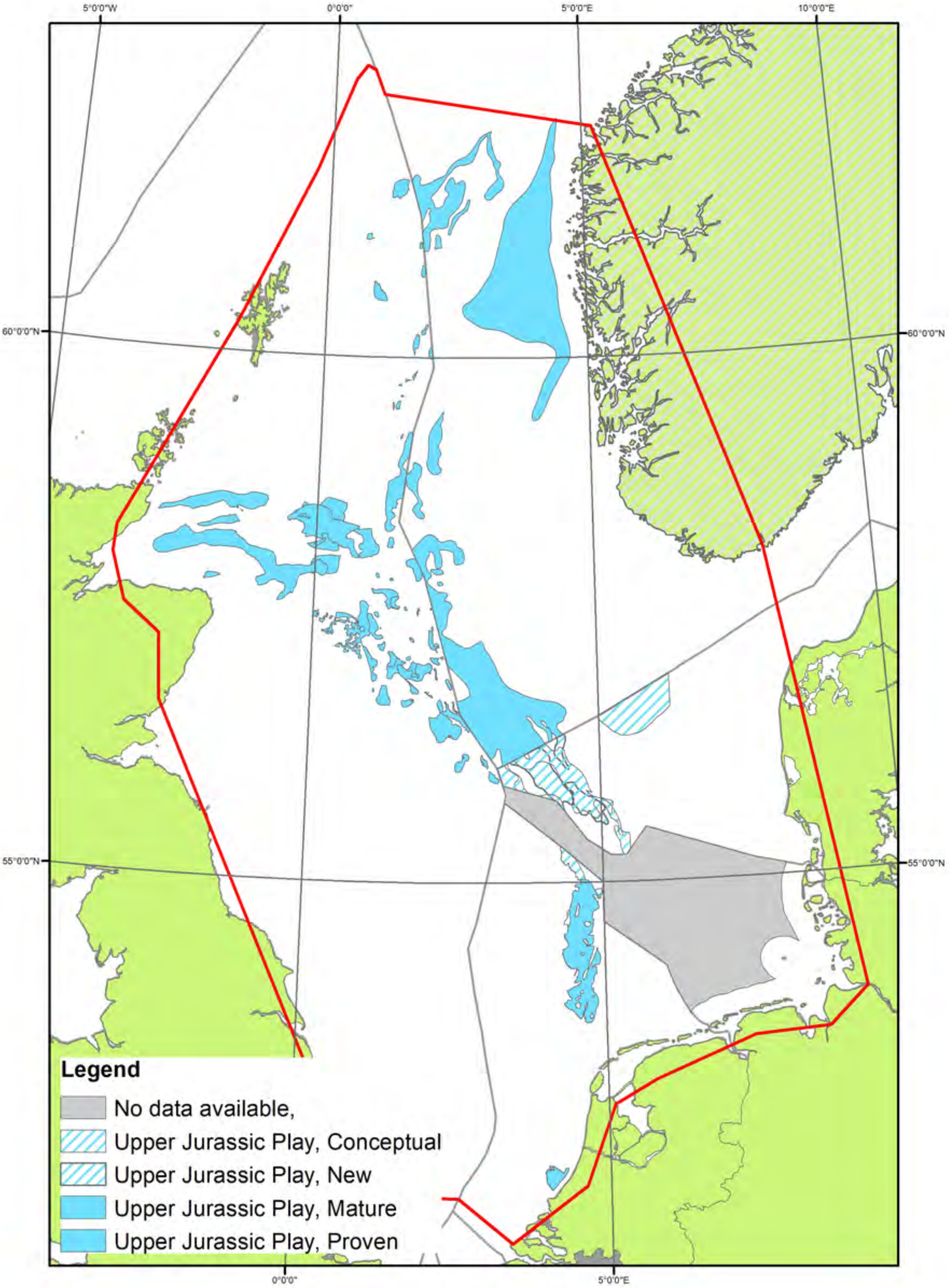


Figure 11-7 Combined cross-border play map for Upper Jurassic play.

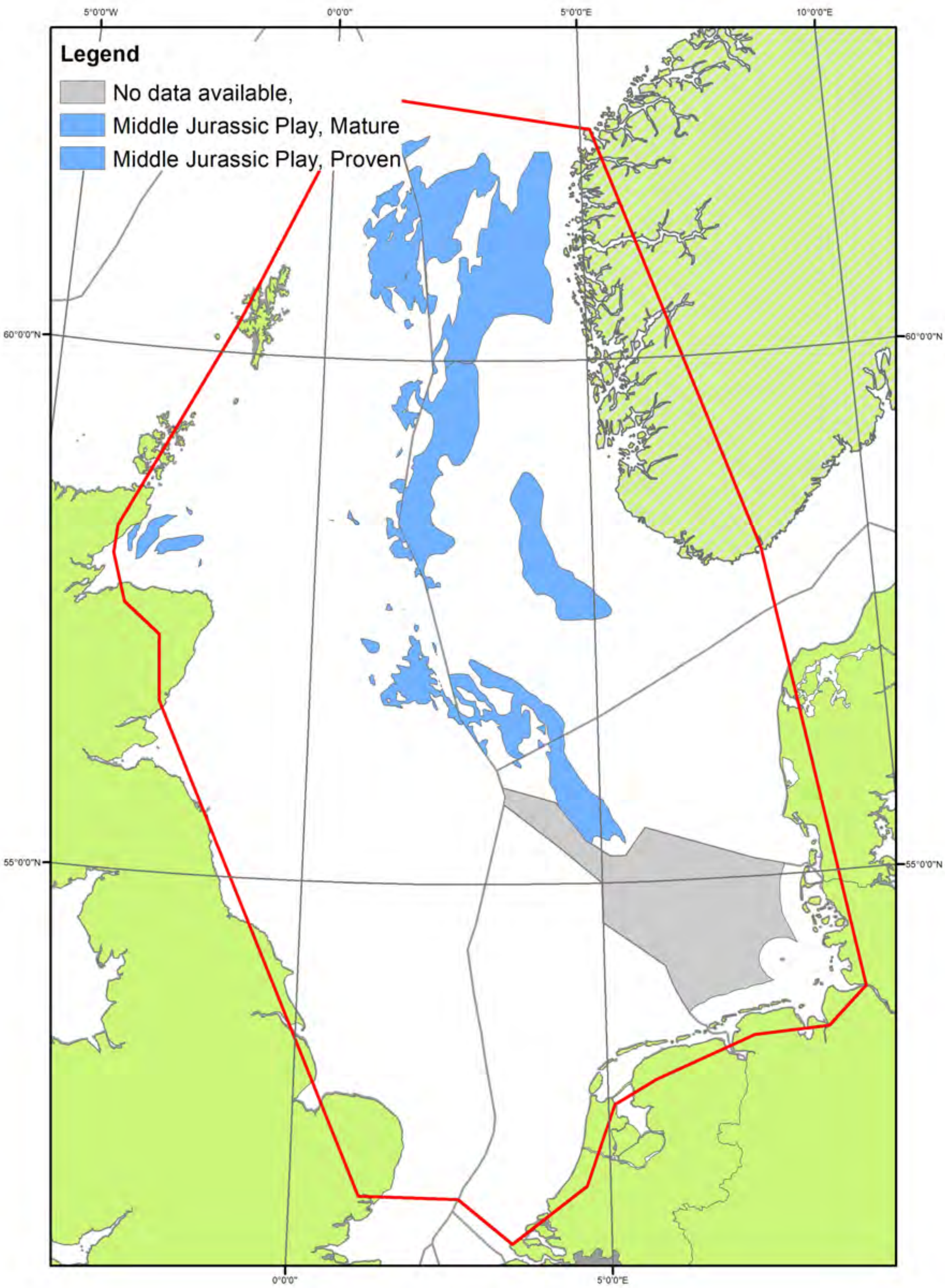


Figure 11-8 Combined cross-border play map for Middle Jurassic play.

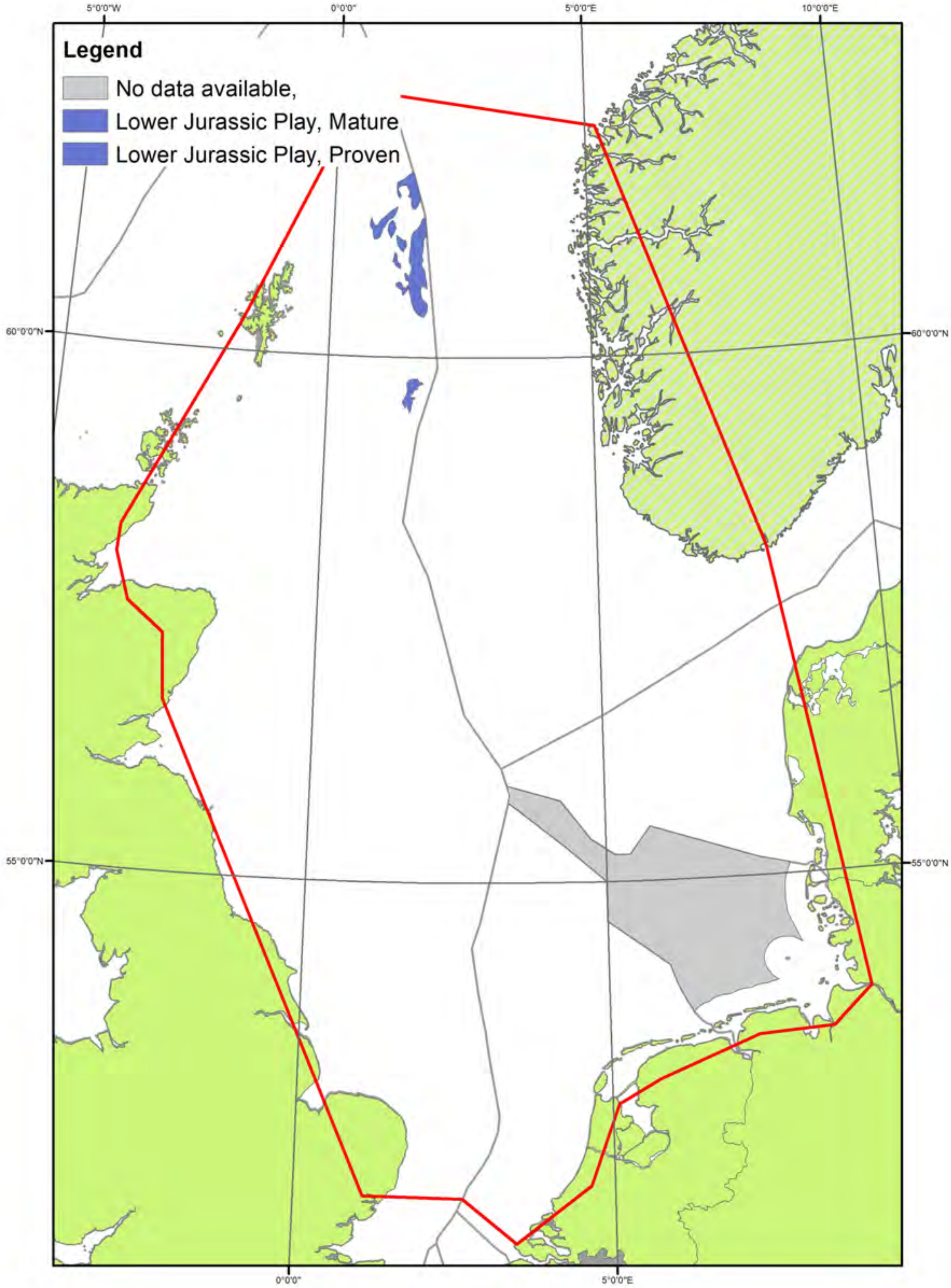


Figure 11-9 Combined cross-border play map for Lower Jurassic play.

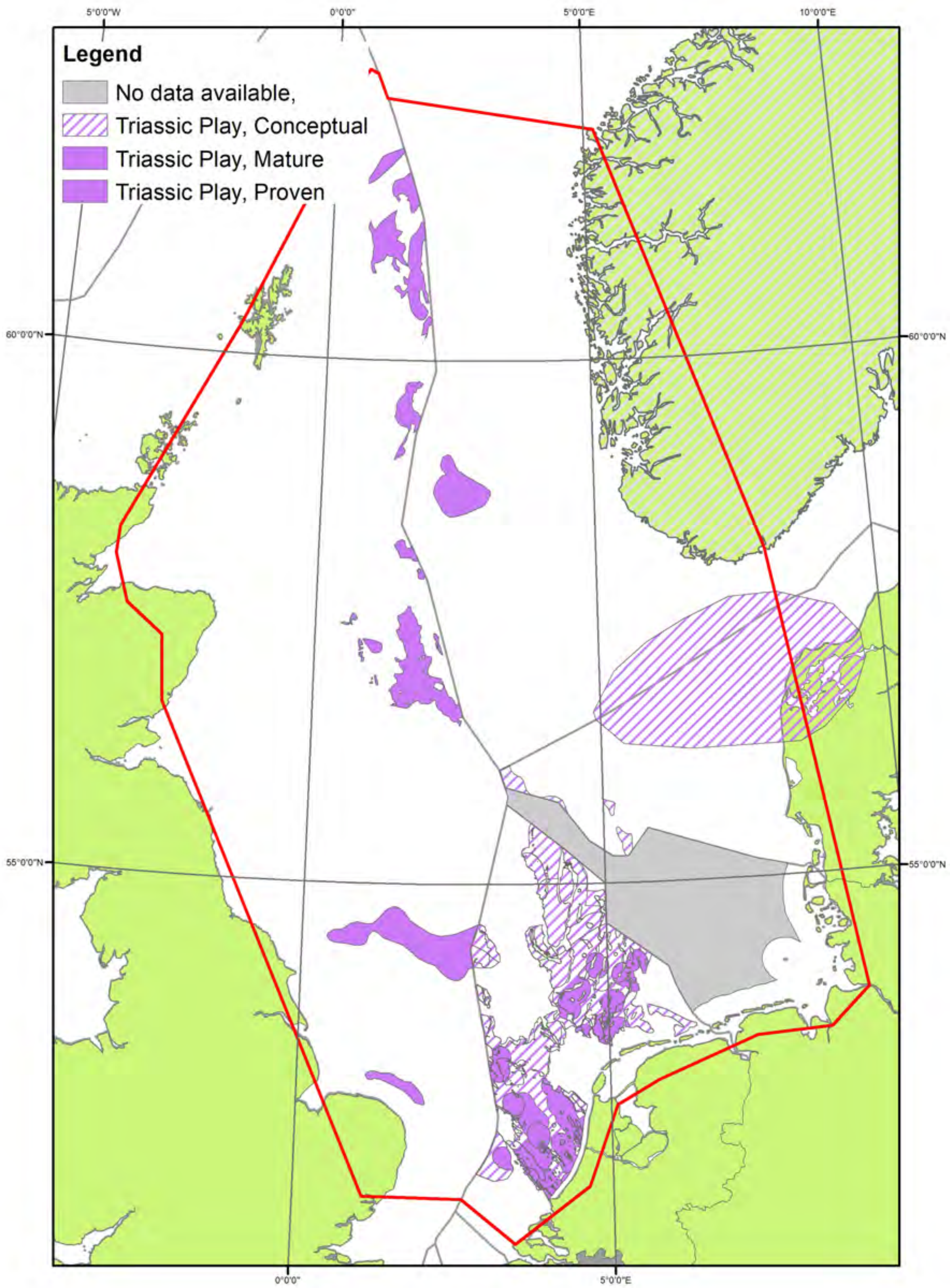


Figure 11-10 Combined cross-border play map for Triassic play.

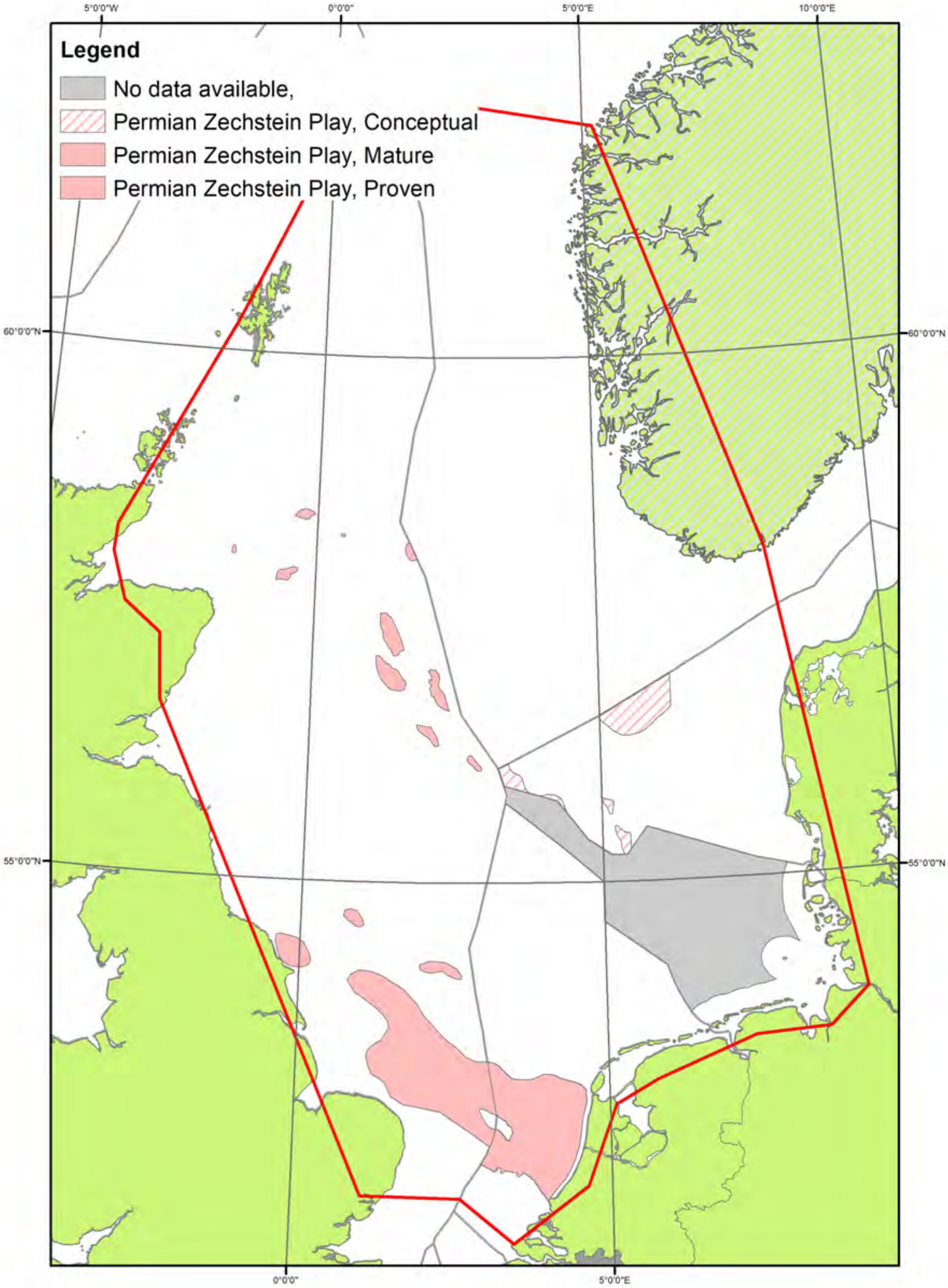


Figure 11-11 Combined cross-border play map for Permian Zechstein play.

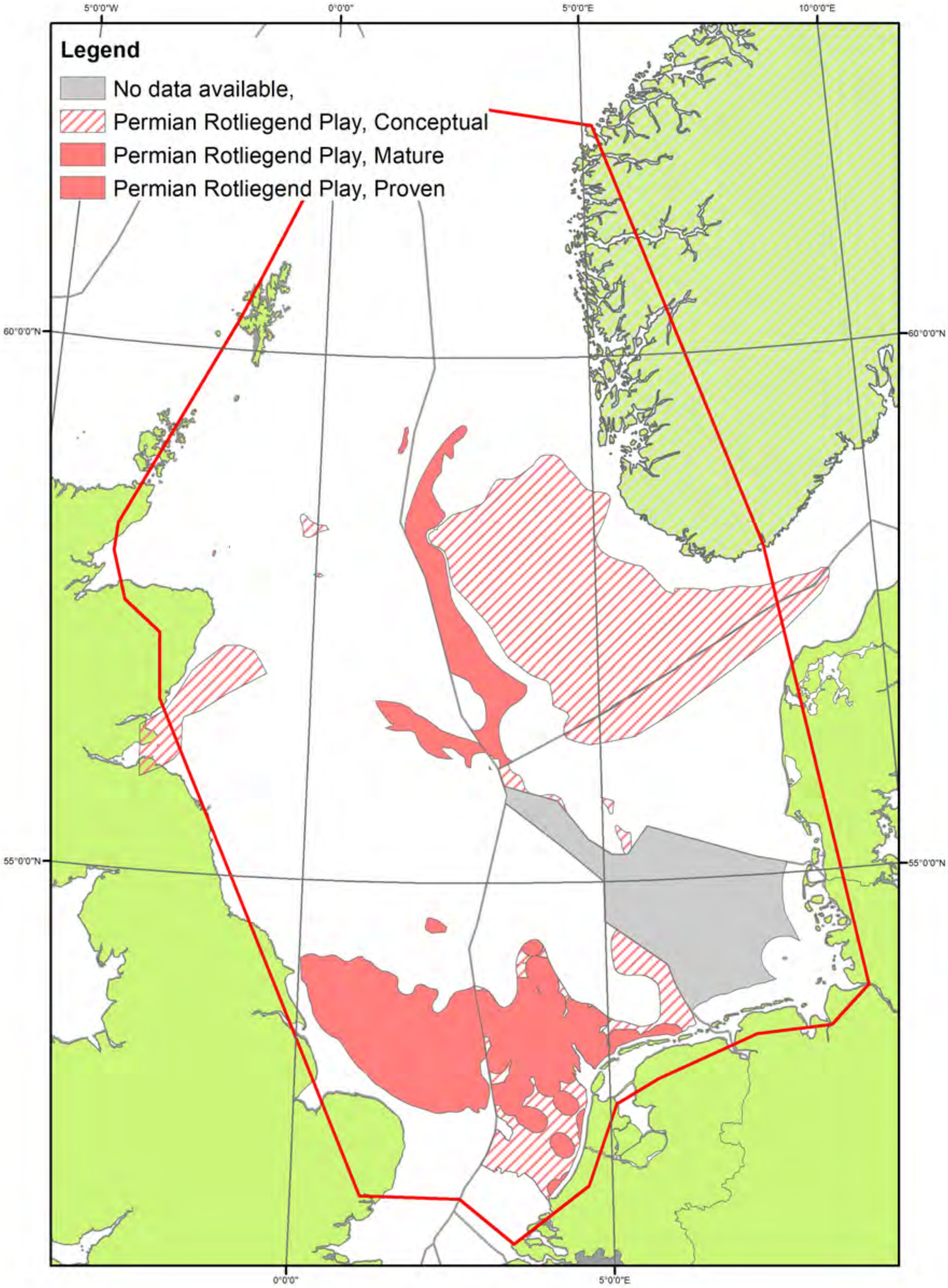


Figure 11-12 Combined cross-border play map for Permian Rotliegend play.

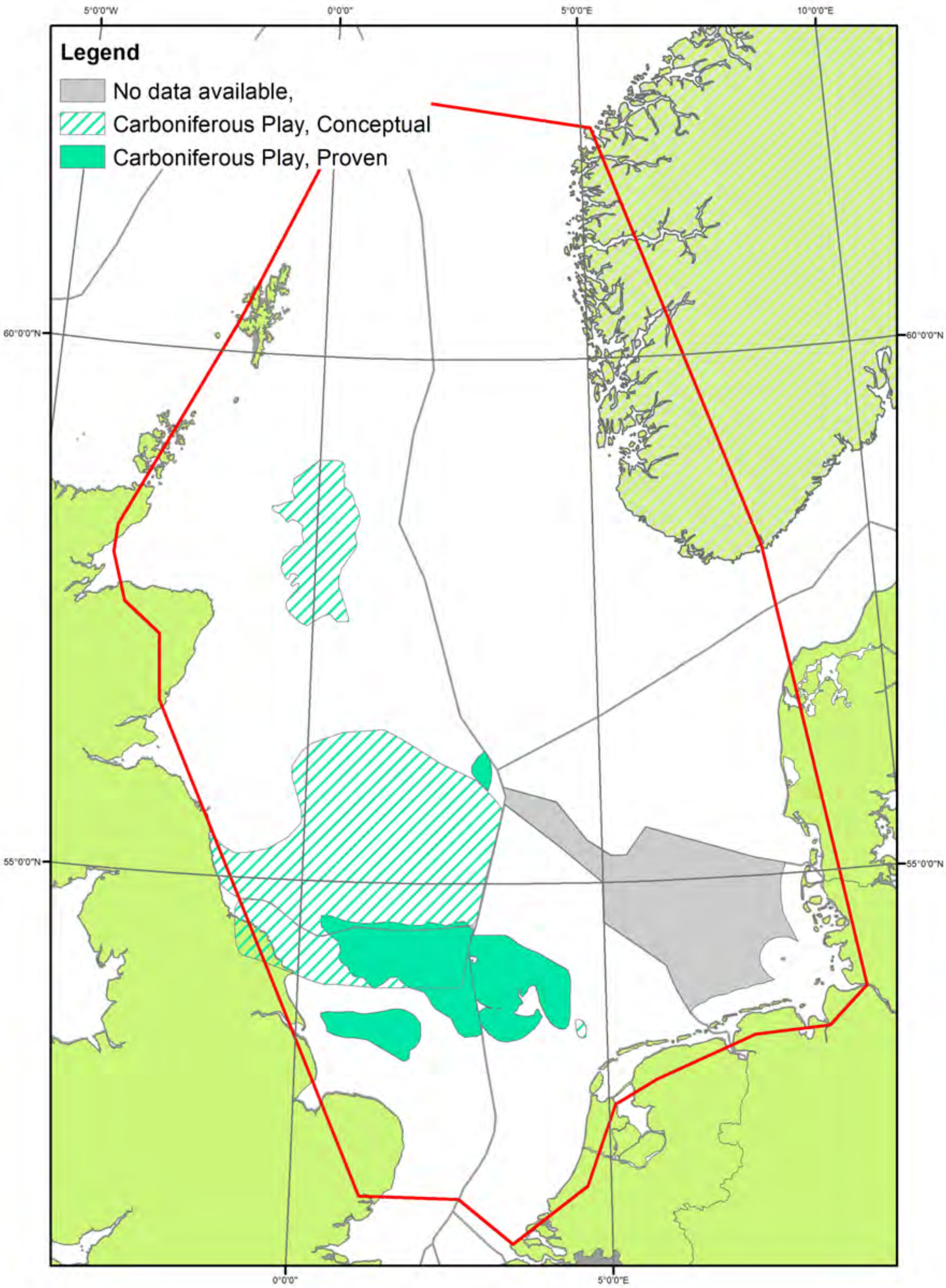


Figure 11-13 Combined cross-border play map for Carboniferous play.