

# Petroleum Systems of the Barents Sea

A geochemical study for improved petroleum system  
understanding

Benedikt Lerch

Dissertation for the degree of Philosophiae Doctor (Ph.D.)



Department of Geosciences

Faculty of Mathematics and Natural Sciences

University of Oslo

Norway

2016

Submitted: 04.May 2016

© **Benedikt Lerch, 2016**

*Series of dissertations submitted to the  
Faculty of Mathematics and Natural Sciences, University of Oslo  
No. 1787*

ISSN 1501-7710

All rights reserved. No part of this publication may be  
reproduced or transmitted, in any form or by any means, without permission.

Cover: Hanne Baadsgaard Utigard.  
Print production: Reprosentralen, University of Oslo.

The world is the geologist's great puzzle-box; he stands before it like the child to whom the separate pieces of his puzzle remain a mystery till he detects their relation and sees where they fit, and then his fragments grow at once into a connected picture beneath his hand.

— Louis Agassiz

Success is 1% inspiration, 98% perspiration and 2% attention to detail.

— Phil Dunphy

## Preface

This thesis has been submitted to the Department of Geoscience at the University of Oslo in accordance with requirements for dissertation for the degree of Philosophiae Doctor. The work that forms the basis for this Ph.D. thesis was conducted under the supervision of Prof. Dr. Dag Arild Karlsen and financed by NORECO ASA.

Although first drillings were conducted during the early 1980ies, the Barents Sea is still considered a frontier area for petroleum exploration. Despite extensive research on the geologic evolution, sedimentology and stratigraphy, geochemical studies reporting on petroleum systems are scarce. It has been suggested relatively early in the exploration history that oils and condensates in the region could be regarded as being mixtures of more than one filling event. Variable results in the early part of the exploration phase are undoubtedly related to the complexities of the region. It is commonly accepted that several phases of uplift, erosion and glacial events during the Cenozoic had great impact on petroleum system elements, but also on already accumulated petroleum. Generation from miscellaneous source rocks, changes in pressure-volume-temperature conditions, secondary in-reservoir alteration, large scale remigration and entrapment mechanisms, and leakage of petroleum are among the processes that impede petroleum system investigation.

The purpose of this work was to provide systematic evaluations of the degree to which oils and condensates are “blends”, or of singular source rock origin, and to evaluate potential variations in maturity signatures, biodegradation, migration induced phase-fractionation and source rock facies. Realizing that petroleum geochemical studies in the Barents Sea may be complicated due to extensive alteration and blends of oils in traps, an attempt was made to decipher the complex signatures: A full geochemical fingerprint of each sample in terms of thermal maturity, secondary alteration effects, age, paleo depositional environments and organic matter input had to be created. Therefore, systematic analysis of three hydrocarbon compound classes has been applied: (1) light hydrocarbon  $C_4$ – $C_8$  compounds, (2) medium range  $C_{10}$ – $C_{20}$  compounds, and (3) biomarker range  $C_{20+}$  compounds.

The results indicate petroleum generation from the early oil window to the late oil/ condensate window. Phase fractionated condensates and oils have been observed in the western part of the Hammerfest Basin. Petroleum mixtures have been identified by varying thermal maturities among the three different compound classes, and paleo biodegradation signatures in combination with fresh, unaltered charges. This indicates at least two migration events of highly variable maturity and/or even source rock facies signatures. Similar geochemical characteristics and use of multivariate statistical analysis led to classification of four petroleum families: (1) Family A: Permian/Triassic sourced, (2) Family B: Carboniferous sourced, (3) Family C: Jurassic sourced, and (4) Family D: Triassic and Jurassic sourced condensates. This project found that oils and condensates have source rock specific origins that can be related to basin locations.

## List of Publications

The project resulted in three scientific papers (hereafter referred to as Paper 1 to 3), presented subsequent to the introduction. Furthermore, numerous conference poster presentations (see in the Appendix), and several talks at workshops and industry meetings have been given. The papers are:

**Paper 1:** Lerch, B., Karlsen, D.A., Abay, T.B., Duggan, D., Seland, R. and Backer-Owe, K., 2016. Regional petroleum alteration trends in Barents Sea oils and condensates as a clue to migration regimes and processes. AAPG Bulletin, 100, 165–190.

**Paper 2:** Lerch, B., Karlsen, D.A., Matapour, Z., Seland, R. and Backer-Owe, K., 2016. Organic Geochemistry of Barents Sea petroleum: Thermal maturity and alteration and mixing processes in oils and condensates. Journal of Petroleum Geology, 39, 125–147.

**Paper 3:** Lerch, B., Karlsen, D.A., Seland, R. and Backer-Owe, K., 2016. Depositional environment and age determination for inferred source rocks from Barents Sea petroleum. Journal of Petroleum Geoscience, Published Online First, doi: 10.1144/petgeo2016-039

## Conference poster presentations

**Poster 1:** Lerch, B., Karlsen, D.A. and Duggan, D., 2014. Migration and Alteration Processes in Barents Sea Oils and Condensates – A Geochemical Approach to improved Petroleum System Understanding. 76<sup>th</sup> EAGE Conference & Exhibition, 16.06. – 19.06. 2014, Amsterdam, the Netherlands.

**Poster 2:** Lerch, B., Karlsen, D.A. and Duggan, D., 2014. The Light Hydrocarbon Paradox of the Barents Sea – Light Hydrocarbon Correlation- & Transformation Parameters in Barents Sea Oils and Condensates. NGF Arctic Energy Conference, 04.06. – 05.06.2014, Tromsø, Norway.

**Poster 3:** Lerch, B., Karlsen, D.A. and Duggan, D., 2015. Geochemical Characterization of Loppa High oils (SW-Barents Sea) and implications for regional petroleum systems. 27<sup>th</sup> IMOG Conference, 13.09. – 18.09.2015, Prague, Czech Republic.

**Poster 4:** Lerch, B. and Karlsen, D.A., 2016. Ages and Depositional Environments of Barents Sea Petroleum. AAPG and SEG, International Conference and Exhibition, 03.04. – 06.04.2016, Barcelona, Spain.

## Oral Presentations

Lerch, B. and Karlsen, D.A., 2014. Light hydrocarbon appraisal on migration and alteration modes in Barents Sea oils and condensates – A geochemical access to improved petroleum system understanding. Force Seminar “Barents Sea Petroleum Analysis”, 27.03. – 28.03.2014, Stavanger, Norway.

Karlsen, D.A., Lerch, B., Abay, T.B. and Backer-Owe, K., 2014. Petroleum Systems in the Barents Sea region. Hydrocarbon Habitats “Play Models in the Barents Sea”, 02.04.2014, Oslo, Norway.

Lerch, B. and Karlsen, D.A., 2015. Migration, mixing and alteration modes in Barents Sea petroleum systems – A regional examination from a geochemical perspective. Seminar “The Jurassic and Triassic Petroleum Systems of the Barents Sea”, 28.04. – 30.04.2015, Longyearbyen, Svalbard, Norway.

Peer Reviewed Articles and Posters Contributed as a Co-Author

Abay, T.B., Karlsen, D.A., Pedersen, J.H., Lerch, B. and Backer-Owe, K. 2014. Regional Variation in the Triassic Organo-Facies signatures of the Barents Sea. Poster presented at the NGF Arctic Energy Conference, 04.06. – 05.06.2014, Tromsø, Norway.

Abay, T.B., Karlsen, D.A., Lerch, B., Olaussen, S. Pedersen, J.H. and Backer-Owe, K., 2016. Novel proof of Migrated Petroleum in the Mesozoic strata in Svalbard and detailed Organic Geochemical Characterization-Implications for Regional Exploration. (accepted in the Journal of Petroleum Geology).

## Acknowledgements

Firstly, I am most grateful to my supervisor Prof. Dr. Dag Arild Karlsen for accepting me as a PhD student to the Petroleum Geochemistry Group. His continuous support throughout the last three years resulted in a steep learning curve from day one. His immense knowledge on petroleum systems and the relaxed way of sharing every part of it is highly appreciated. It was always a pleasure being challenged to think in unconventional ways and to solve problems from different perspectives.

NORECO ASA is acknowledged for project funding and cooperation. Reinert Seland and Deirdre Duggan are acknowledged for exchanging ideas, constructive support and valuable input.

Many thanks go to Kristian Backer-Owe for being a great office mate. Inspiring (and often long) discussions about geochemistry, the Norwegian society and life in general have been lots of fun and a useful distraction during the writing process.

Special thanks go to Tesfa and Zagros for endless lunches, coffee breaks, table tennis matches, inspirational discussions on geochemistry and life in general and a lot of fun during conference trips. Many thanks also to Steven, Valentin, Anna, Ivar, Heddi and Christopher for the many lunches, coffee breaks, and the occasional beers.

Thanks a lot to: Jannis and Helen, Sanni and Felix, Felix, Arnd and Maike, Eli and Michel, Thore, Pauli and Joke for being great friends over the years. It was awesome enjoying “a piece of home” in Oslo from time to time. Cheers to you all.

A big thank you to Kate and Ole with Elida, Kelly and Øyvind, Halla and Øyvind with Magnus, and Eline and Johan with Saga. You guys made it so easy to forget about university life and became part of our new family in Norway.

My parents are thanked for their continuous support, encouragement and endless visits and calls during my whole study period over the last 10 years. Even if our disciplines are slightly different, the organic (geo)chemistry is still in the family. My parents in law are also thanked for their support and many visits over the last years.

Last but not least, the biggest thanks to my wife Gesine for her incredible never-ending support, for joining me to our “Norwegian adventure” without the bat of an eyelid, for her endless encouragement and always being there for me. You are the best! And to our newborn son, Louis Fredrik, who enjoys welcoming me with a full diaper after work.

Table of Contents	
Preface.....	I
List of Publications.....	II
Acknowledgements.....	IV
1 Introduction .....	1
1.1 Why Petroleum Geochemistry .....	1
1.2 Petroleum Formation .....	2
1.4 The Arctic as a Key Petroleum Province for Future Fossil Fuel Resources .....	8
1.5 The Norwegian Barents Sea .....	10
2 Petroleum Geology of the Barents Sea .....	13
2.1 Geological Evolution .....	13
2.2 Source Rocks of the Barents Sea.....	15
2.3 Reservoir Rocks of the Barents Sea .....	19
2.4 Influence of Uplift and Erosion on Petroleum Systems .....	21
2.4.1 Cenozoic Uplift and Erosion.....	21
2.4.2 Source Rock Maturation .....	23
2.4.3 Reservoir Quality.....	23
2.4.4 Seal Properties .....	23
2.4.5 Migration, Remigration and Changes in PVT Conditions .....	24
2.4.6 Bacterial Alteration.....	27
3 Results and Implications .....	29
3.1 Paper 1.....	31
3.1.1 Findings.....	31
3.1.2 Implications .....	32
3.2 Paper 2.....	33
3.2.1 Findings.....	33
3.2.2 Implications .....	34
3.3 Paper 3.....	35
3.3.1 Findings.....	35
3.3.2 Implications .....	36
3.4 Samples and Analytical Procedures.....	37
4 Concluding Remarks – Petroleum System Implications .....	39
4.1 The Oil Families in a Regional Context .....	54
4.2 Suggestions for Future Work .....	58
5 References .....	61
6 The Papers.....	
Paper 1.....	
Paper 2.....	

Paper 3.....	
Appendix.....	



# 1 Introduction

## 1.1 Why Petroleum Geochemistry

Petroleum geochemistry combines the subjects of petroleum geology and organic geochemistry, which applies chemical principles to study the origin, generation, migration, accumulation and alteration of petroleum (Hunt, 1979). The origin of petroleum geochemistry can be dated back to the late 19<sup>th</sup> century, when petroleum was distilled into its different fractions or cuts to obtain kerosene (Hunt et al., 2002). In 1954, the first known source rock – crude oil correlation has successfully been employed by using fractionation techniques, column chromatography and elemental analysis (Hunt et al., 1954). Yet, the advent of petroleum geochemistry was in the mid-1960s with the commercial availability of gas chromatographs that led to the development of molecular based source rock parameters concerning the organic facies and maturity, as well as maturity and facies parameters for use in oil-oil correlation studies. Most of these correlation parameters were based on gas chromatogram – flame ionization detector (GC-FID) methodologies, and among the first compounds that have been identified in sediment and crude oil samples were the *n*-alkanes. But also methods based on stable carbon isotopes and elements like Nickel/Vanadium (Ni/V) have been used for correlation studies. With the advent of fast scanning mass spectrometers, the gas chromatography – mass spectrometry (GC-MS) systems developed and so did the biomarker concept in 1964 (Hunt et al. 2002). Biomarkers, also

known as chemical fossils, geochemical fossils or biological markers are compounds found in petroleum and sedimentary rocks that can be linked to their structurally similar precursor compounds found in living organisms. The discovery of similar biomarkers in both the bitumen of the source rock and in the expelled petroleum thus established the idea for correlation purposes and also to discern the origin and occurrence of petroleum (cf. Tissot and Welte, 1984). Since then, powerful methodologies have been developed and applied in petroleum geochemistry: (1) petroleum – source rock correlation and petroleum – petroleum correlation, (2) evaluation of thermal maturity based on both source rocks and petroleum, (3) interpretation of secondary alteration effects such as water-washing, biodegradation and fractionation in petroleum accumulations, (4) evaluation of organic matter within the source rock to characterize the depositional environment, and (5) evaluation of petroleum generation kinetics to assess the thermal history and generation-migration-accumulation processes as part of basin modelling studies. In 1977 Espitalié et al. introduced the Rock-Eval instrument that soon became a standard method for source rock characterization and evaluation. With help of the Rock-Eval parameters, it became possible to easily classify the kerogen type in rocks, the thermal maturity and also the generation potential of the rocks. Until today, enhancement and development of new analytical techniques has led to discoveries of new biomarkers in petroleum and sedimentary rocks. Thus, petroleum geochemistry has experienced a steadily increasing focus in both academia and exploration, and petroleum geochemistry will continue to play a critical role in finding future petroleum resources (Peters and Fowler, 2002). For extensive literature on principles and applications of petroleum geochemistry, the reader is referred to the following books: Tissot and Welte (1984), Bordenave (1993), Hunt (1995), Killips and Killips (2005), Peters et al. (2005) and Huc (2013).

## 1.2 Petroleum Formation

The term organic matter “refers solely to material comprised of organic molecules in monomeric or polymeric form derived directly or indirectly from the organic parts of organisms” (Tissot and Welte, 1984, p.3). Before the organic matter is converted into petroleum, it has to be deposited and preserved. The organic material is buried together with inorganic particles, and with increasing burial depth these layers will be compacted to sedimentary rocks. Hereby, the transformation of the organic matter into petroleum products is strictly depended on geological factors that occur within a sedimentary basin as e.g., the sedimentation rate and the associated subsidence of the source rocks and the thermal gradient in the basin.

The transformation of organic matter into petroleum i.e. oil and gas can be divided into three different maturation stages termed diagenesis, catagenesis and metagenesis (Tissot and Welte, 1984).

### *Diagenesis*

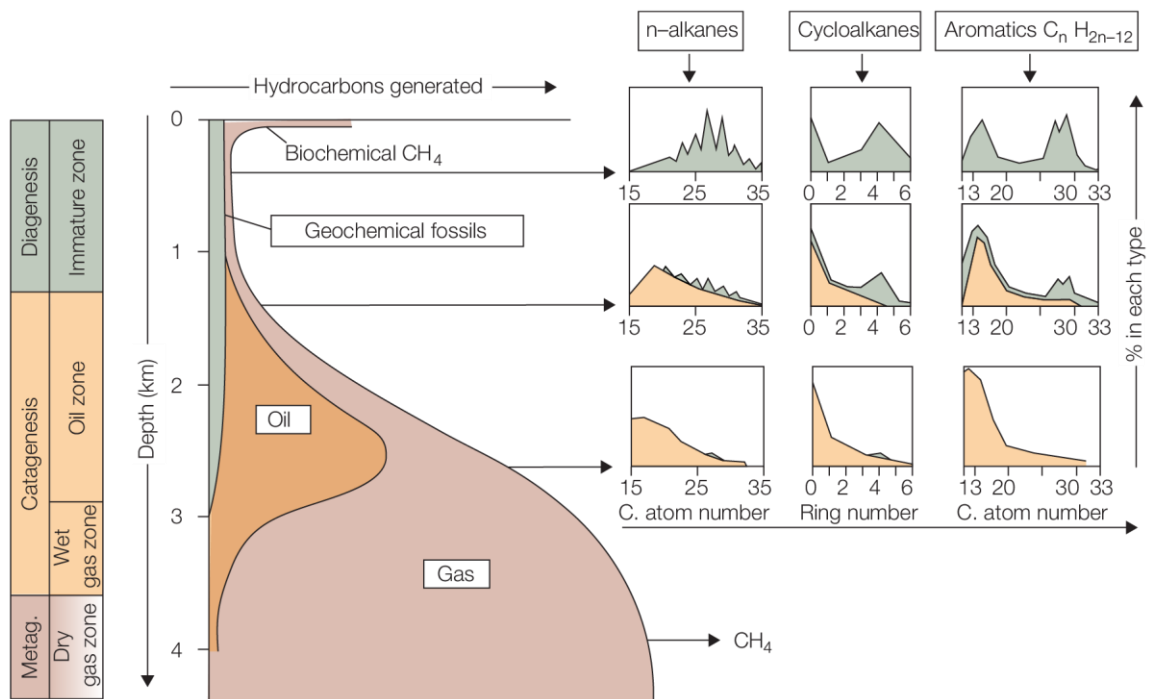
The term diagenesis refers to the earliest stage of alteration of products of primary production (Killops and Killops, 2005). Biological, physical and chemical reactions occur under low temperature conditions in sediments close to the surface, with up to a few hundreds or thousands meters of depth (Tissot and Welte, 1984; Horsfield and Rulkötter, 1994). In temperature regimes ranging from 60–80°C the organic matter is preserved in the form of biomacromolecules and/or condensed to geopolymers (Killops and Killops, 2005; Tissot and Welte, 1984). Due to polycondensation the initial organic matter becomes progressively insoluble with increasing burial depth and time. This process results in an increased yield of geomacromolecules that are integrated into the sediment (Killops and Killops, 2005). At the end of the diagenesis, the polycondensed organic matter within the sediment consists mainly of kerogen, and even some amounts of bitumen (Tissot and Welte, 1984; Killops and Killops, 2005). The main product that is generated during this stage is biogenic methane (Fig. 1).

### *Catagenesis*

The second stage, also known as the oil and gas generating phase, is called catagenesis. One of the main processes in this stage is the thermal alteration of kerogen to bitumen. The main driving force for the formation of bitumen is an increase in temperature that coincides with ongoing subsidence of the sedimentary basin (Tissot and Welte, 1984). Primary cracking reactions or the generation of petroleum commonly occur between 70 and 150°C, while the cracking reactions are dependent on the origin of the kerogen (see next paragraph). A temperature increase determines the expelled and generated petroleum products. First, hydrocarbons with a high molecular weight will be expelled, but with ongoing thermal maturation greater amounts of lighter/smaller hydrocarbons will be generated. For this reason, the catagenesis stage is divided into the oil window and the wet gas zone (Fig. 1). During the wet-gas zone, mainly C–C bonds tend to break and result in an increasing amount of generated C<sub>1</sub>–C<sub>5</sub> gases. However, during the metagenesis stage, or the “dry-gas” zone, hydrocarbon generation is dominated by methane generation (Tissot and Welte, 1984).

### *Metagenesis*

The metagenesis stage is also referred to as the gas generation stage. At great depths the source rock is exposed to the highest thermal stress (Horsfield and Rulkötter, 1994). It can be considered as the last stage of organic matter evolution where only methane, hydrogen and highly carbonized solid organic matter are stable (Tissot and Welte, 1984; Horsfield and Rulkötter, 1994). The subsurface temperatures that occur in the metagenesis stage are, in general, high enough (>200°C) to crack already generated hydrocarbons i.e. oil into gaseous compounds.



**Fig. 1:** Generalized scheme of petroleum generation. The Figure illustrates the relative amount and type of hydrocarbons that are generated during the three different stages: diagenesis, catagenesis and metagenesis. Note that with increasing burial depth and increasing maturity the amount of lighter hydrocarbons increases. Modified after Tissot and Welte (1984) and Allen and Allen (2013).

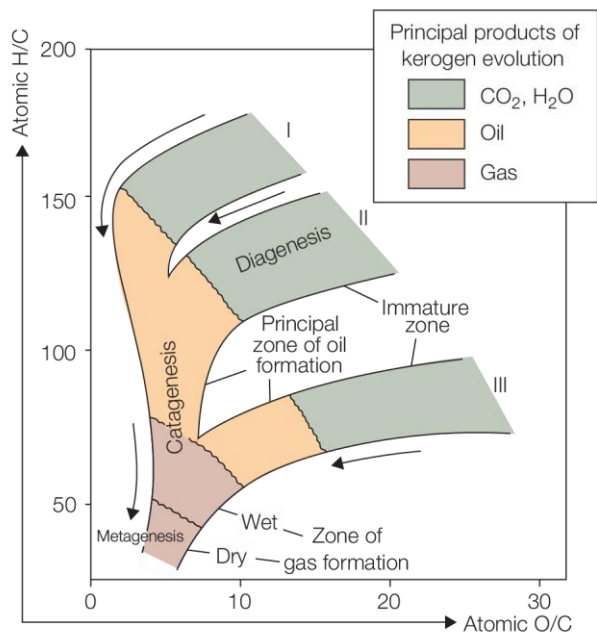
The kerogen types are defined as Type I–III, and are described in the order of decreasing petroleum potential as simplified shown in Figure 2.

#### *Type I kerogen*

Kerogen Type I is mainly deposited in lacustrine environments under anoxic and low energy conditions. The organic material is dominated by lipids deriving from algal material. Yet, some Type-I kerogens may also derive from bacterially reworked or marine organic matter. Type I kerogen has the highest H/C ratio and the lowest O/C ratio (Fig. 2), that results in a high oil potential (Tissot and Welte, 1984; Killips and Killips, 2005; Vandenbrouke and Largeau, 2007).

#### *Type II kerogen*

Type II kerogen is formed under reducing marine conditions and mainly derives from allochthonous and autochthonous input of planktonic and higher plant organic matter. Due to the high H/C and O/C ratios, kerogen Type II is defined as oil-prone (Fig. 2). Still, kerogen Type II has the potential to generate gas under high temperature conditions (Tissot and Welte, 1984; Killips and Killips, 2005;



Vandenbrouke and Largeau, 2007). In addition, kerogen Type II-S will occur in depositional environments that support the incorporation of higher amounts of sulphur.

**Fig. 2:** Van Krevelen Diagram showing the different kerogen types in relation to the different hydrocarbon generation stages. Modified after Tissot and Welte (1984) and Allen and Allen (2013).

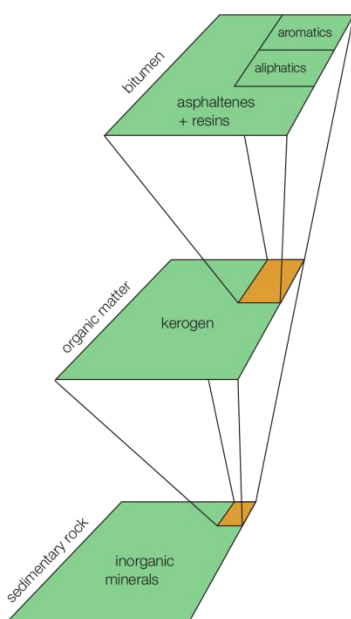
### *Type III kerogen*

Organic matter that constitutes kerogen Type III derives from higher plant debris that is, in general, deposited in terrestrial to deltaic environments where oxic redox conditions prevail. Yet, due to intensive transportation processes, terrestrial derived organic matter can also be found in deep marine environments. Type III kerogen is characterized by low H/C ratios and high O/C ratios (Fig. 2), which results in a mainly gas generating hydrocarbon potential (Tissot and Welte, 1984; Killops and Killops, 2005; Vandenbrouke and Largeau, 2007).

### *Type IV kerogen*

Kerogen Type IV is defined as reworked and transported, probably terrestrial organic matter that has no hydrocarbon generation potential (Killops and Killops, 2005).

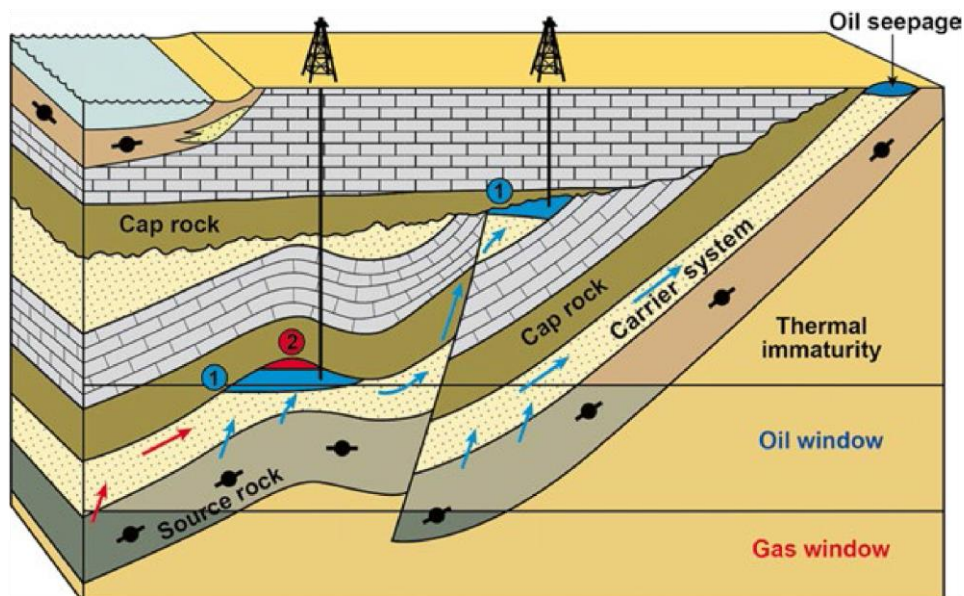
Kerogen, in contrast to bitumen, is insoluble in organic solvents. During increasing thermal maturation of the source rock, the kerogen is converted into bitumen. Bitumen can occur as liquid or solid hydrocarbon deposits, while petroleum encompasses gaseous and liquid hydrocarbons, i.e. oil and gas. The three main fractions of bitumen are shown in Figure 3 (Killops and Killops, 2005).



**Fig. 3:** Composition of organic matter in sedimentary rock (modified after Killops and Killops, 2005)

### 1.3 Petroleum System Elements

In this project, petroleum geochemical methodologies have been the working tool to evaluate the relationship between oils and condensate samples in the Norwegian part of the Barents Sea. This was done for the purpose of a better understanding what is normally referred to as the “Petroleum System”. The current concept of the “Petroleum System” has previously been described as: “the oil system” (Dow, 1974), “the generative basin concept” (Demaison, 1984), “the hydrocarbon machine” (Meissner et al., 1984), and “the independent petroliferous system” (Ulmishek, 1986). However, the petroleum system concept was later redefined as “the genetic relationship between a pod of active source rock and the resulting oil and gas accumulations” (Magoon and Dow, 1994, p.3), including all relevant geologic elements and processes that occur in time and space and finally lead to the accumulation of petroleum. These essential elements are source and reservoir rocks, seal rocks and overburden rocks (Fig. 4), while the processes include trap formation and generation-migration (primary and secondary)-accumulation (Magoon and Dow, 1994). The term “petroleum” refers to elevated concentrations of: (1) thermal or biogenic gas, (2) condensates, (3) crude oils, and (4) asphalts that occur in nature (Magoon and Dow, 1994). One of the most powerful tools in petroleum systems analysis is the application of petroleum geochemistry. Source rock evaluation and analysis of liquid and gaseous hydrocarbons provide essential input data for basin modelling studies. Petroleum geochemistry integrates chemical principles for investigation of the origin, migration, accumulation and alteration of petroleum (Brooks and Welte, 1984).



**Fig. 4:** Sketch summarizing the essential elements of a petroleum system (Huc and Vially, 2012)

A petroleum system investigation commonly starts with the discovery of a hydrocarbon accumulation regardless of size (Magoon and Dow, 1994). The lowermost element in a petroleum system, the source rock, can be characterized by three geochemical requirements: (1) the quantity of the organic matter, (2) the quality of the organic matter, and (3) the thermal maturity or the extent of burial heating (Peters and Cassa, 1994). The source rock can furthermore be defined as active when hydrocarbons are generated and expelled, as inactive when hydrocarbon generation terminated, and spent when the source rock reached the post mature stage.

All rocks that have sufficient porosity, either primary or secondary, and have a high permeability that allows fluid exchange e.g., water and oil, can be considered as a reservoir rock. The reservoir rock can be considered as a part of the carrier system. The function of the cap rock is to hold the petroleum accumulation in place (Fig. 4). Therefore the displacement or capillary pressure of the cap rock has to be greater than the upward buoyancy pressure of the underlying petroleum column (Downey, 1994). In general, ductile cap rocks as e.g., salt or anhydrite provide greater chances to preserve a petroleum accumulation in comparison to carbonate mudstones or cherts (Downey, 1994).

For a trap to be efficient, the reservoir rock and the cap rock, both considered being critical elements, have to be in place. Traps are defined as a geometric arrangement of rocks that allows petroleum to accumulate, whereas they must be capable of exchanging fluids e.g., water and oil. Thus, traps can also be regarded as focal points of active fluid exchange (Biddle and Wielchowsky, 1994) and can occur as structural, stratigraphic or a combination of both (Fig. 4). The largest part of the basin fill is the overburden rock. Positive aspects linked with the overburden rock are the burial of the source rocks to greater temperature regimes and the associated thermal maturation. Furthermore, the compaction of cap rocks, which increases the sealing capacity, can be understood as a positive effect. On the other hand, the compaction of reservoir rocks and the associated reduction in porosity and permeability can also be ascribed to burial by the overburden.

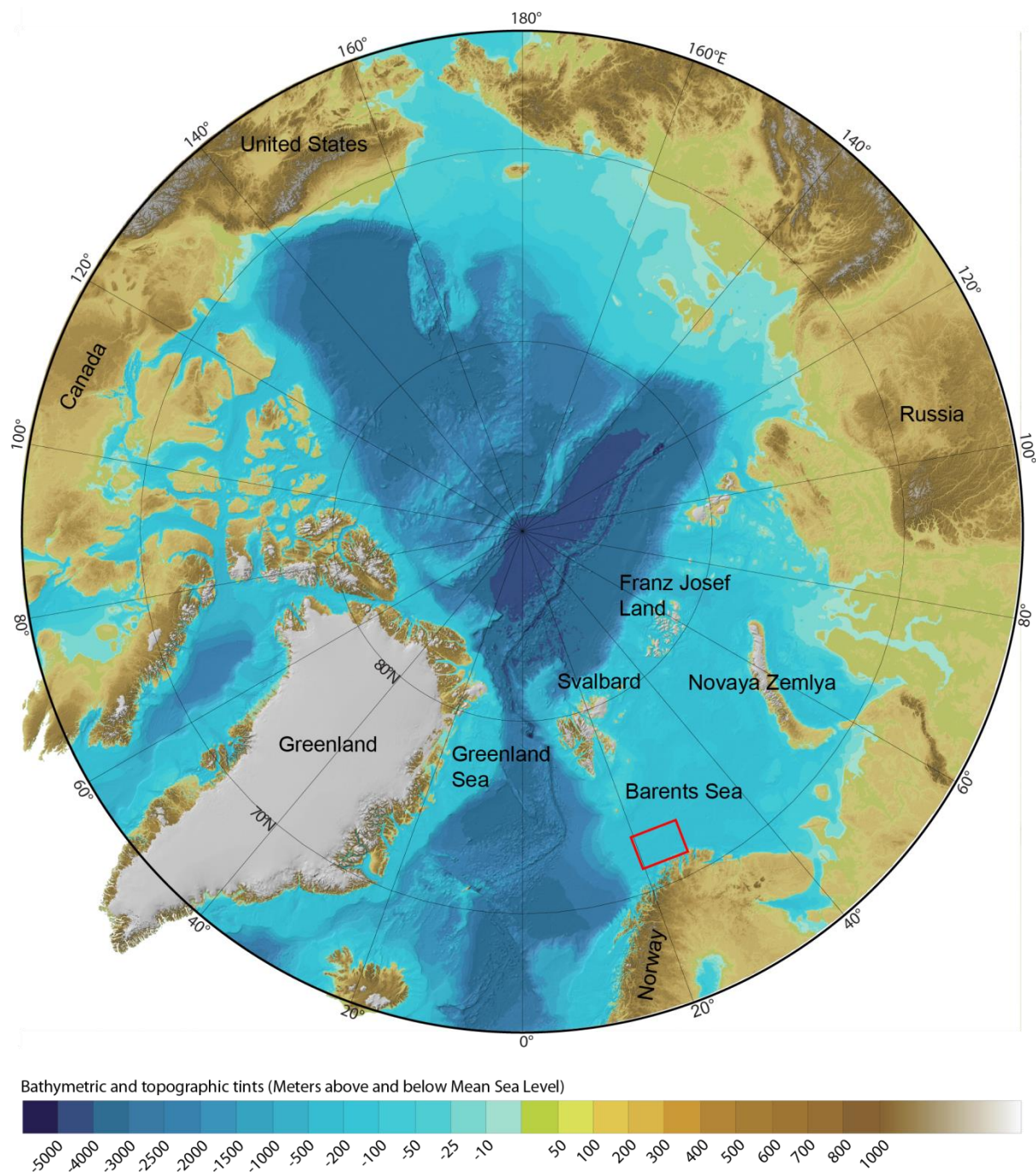
After the petroleum has been generated in the source rock it eventually reaches a porous and permeable carrier system, where the petroleum will migrate into the reservoir (England et al., 1987). However, the process of migration can be subdivided into various steps. Primary migration is the process where the generated petroleum initially moves from the fine-grained, low permeable source rock into the more permeable carrier rock (Hunt, 1979; Tissot and Welte, 1984; England et al., 1987). Secondary migration is referred to the movement of petroleum beyond the point where the hydrocarbon exits the pod of active source rock (England, 1994). Secondary migration, in general, occurs within a permeable carrier rock, a carrier network or along faults and terminates in a petroleum accumulation if all reservoir requirements are met (Tissot and Welte, 1984; England et al., 1987). One unknown variable is the amount of the generated and expelled petroleum that finally reaches the reservoir (England, 1994).

The history, capacity and efficiency of a trap define the durability of a petroleum accumulation that can range from a few million years to several hundreds of million years (Huc, 2013). Huc (2013) furthermore suggests that a trap can be understood as a transition zone that delays the movement of petroleum to the surface. Nonetheless, successful accumulation of petroleum requires the presence of a low permeable and sealing rock that restricts further vertical movement by capillary forces (England et al., 1987).

#### 1.4 The Arctic as a Key Petroleum Province for Future Fossil Fuel Resources

Due to the steadily increasing world population, energy consumption will grow by ca. 56% between 2010 and 2040 (U.S. Energy Information Administration, 2014). Even if renewable energy sources increase with up to 2.5% each year, fossil fuels will still be the most dominant and important energy supply with up to 80% through 2040 (U.S. Energy Information Administration, 2014). Due to rising energy consumption and the resulting increase in demand for fossil fuels, the search in areas that were not previously open for petroleum exploration is inevitable.

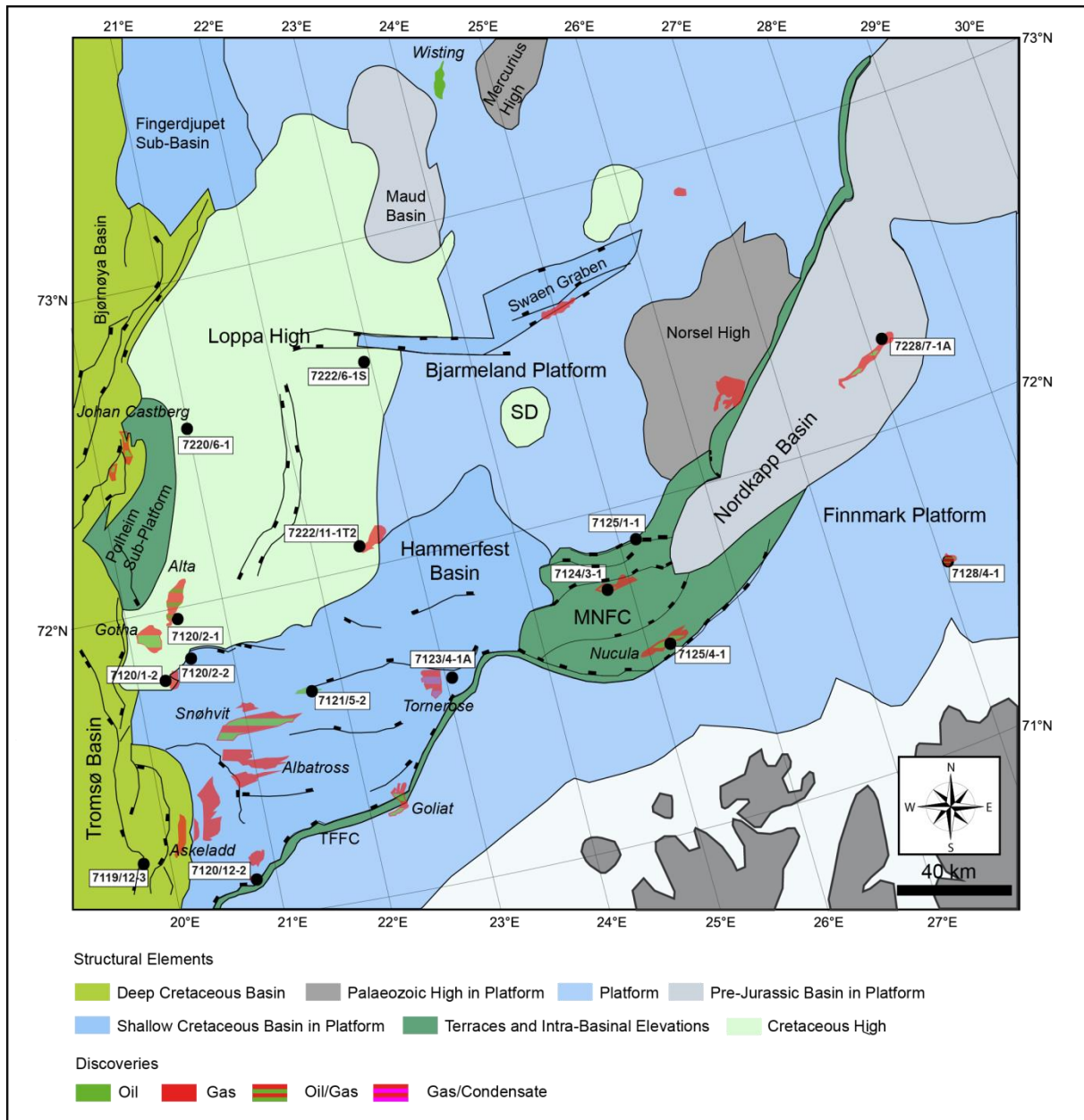
In respect to commercial exploitation, the Arctic regions north of the Arctic Circle (66°N) (Fig. 5) have been drawn attention resulting in 450 discoveries representing almost 40 different petroleum systems (Chew and Abouille, 2011). The United States Geological Survey (USGS) estimated that about 30% of the world's undiscovered gas and 13% of the world's undiscovered oil may be found in high latitudes (Gautier et al., 2009). In this scenario, the Barents Sea is considered one of the major future petroleum provinces in the world. Klett et al. (2009) estimated the recoverable petroleum reserves on the Barents Shelf, for both Norwegian and Russian waters, to be more than 11 billion barrels of crude oil, 380 trillion cubic feet of natural gas and 2 billion barrels of natural gas liquids. A vast amount of these undiscovered reserves are suggested to be found offshore in water depths less than 500m.



**Fig. 5:** Map showing the bathymetry of the Arctic and topographic elevation of the surrounding land masses (modified after Jakobson et al., 2012). The red polygon indicates the study area in the SW Barents Sea.

## 1.5 The Norwegian Barents Sea

The first licenses for oil and gas exploration in the Norwegian Barents Sea were awarded in 1979, leading to the discovery of the Alke and Askeladd gas fields in 1981 (Fig. 6), and the Snøhvit discovery in 1984. Before the end of 1989, 45 exploration wells were drilled in the Norwegian part of the Barents Sea and all discoveries were made in the Hammerfest Basin (Fig. 6). Jurassic sandstones have been proven to be the most valuable (Johansen et al., 1993). Due to the fact that mainly gas bearing reservoirs have been encountered in the Norwegian part, the Barents Sea was mainly considered a gas prone area and suffered low exploration interest. However, optimism turned back when the Goliat discovery (wells 7122/7-2, 7122/7-3, 7122/7-4 S) was made in 2000 (Fig. 6). The revival in Barents Sea exploration led to a total number of 149 drilled wells until the end of 2016, while the success rate is about 50% of direct oil and gas discoveries with most of the dry wells containing oil and gas shows (Norwegian Petroleum Directorate, 2015). The new hope for finding more oil is mainly based on exploration results obtained during the last 5 years: the Johan Castberg discovery (Skrugard, well 7220/8-1, April 2011; Havis, well 7220/7-1 January 2012; Drivis, well 7220/7-3 S, May 2014), Nucula discovery (well 7125/4-2, early 2007), Wisting Central discovery (well 7324/8-1, September 2013); the Gotha discovery (well 7120/1-3, October 2013); and the Alta discovery (well 7220/11-2, October 2014) among others. Until now, most discoveries have been made in the western part of the Norwegian Barents Sea. A breakthrough was reached with the discoveries of the Gotha and Alta fields on the Loppa High. The discoveries have been successfully tested in Permian carbonates, and for the first time, a Permian carbonate play has been proven on the Norwegian Continental Shelf. Therefore, the Loppa High area gained rising interest, and it is believed that several discoveries will be made in the same formations. However, other promising areas for future exploration are the southeastern Barents Sea, close to the Russian part and the Hoop area in the north.



**Fig. 6:** The study area with its main structural elements, hydrocarbon discoveries and wells from which the samples were collected (modified from NPD (2015) and Lerch et al., (2016b)).



## 2 Petroleum Geology of the Barents Sea

The following paragraph provides an overview about the geological evolution of the Barents Sea and the most important source rock and reservoir rock intervals. Furthermore, the effects of uplift and erosion on petroleum systems elements are described.

### 2.1 Geological Evolution

The Barents Sea is an intra-cratonic basin located between the Norwegian and Russian mainland in the south and Svalbard in the north. In the west it is bordered by the Norwegian–Greenland Sea and by Novaya Zemlya in the east (Fig. 5). Faleide et al. (1984) and Worsley (2008) described the highs, basins, platforms and diapiric provinces as main the structural elements (Fig. 6) that developed from Devonian to Early Cenozoic (Faleide et al., 2008), and which have been active at varying times during the geologic history (Nøttvedt et al., 1993).

The closure of the Iapetus Ocean in the Late Cambrian can be seen as the earliest compressional event related to the Caledonian orogeny that initiated the NE–SW oriented structural trend (Berghlund et al., 1986). Thus, it was suggested that mainly Caledonian trends have influenced the structural development from the Late Paleozoic to Cenozoic times (Faleide et al., 1984; Gabrielsen et al., 1990). Deposition of Old Red Sandstones has been the result of uplift and erosion of the Caledonian orogen

during Late Silurian–Early Devonian times (Faleide et al., 1984). Rifting during the Late Devonian–Middle Carboniferous resulted in the formation of depressions and graben structures (Nøttvedt et al., 1993) that were characterized by the accumulation of thick sedimentary packages representing clastics, carbonates and evaporites (Faleide et al., 1984).

Tectonic quiescence and increasing sea-level during the Late Carboniferous–Permian initialized the evolution of carbonate platforms, while hypersaline sediments were deposited during sea level low-stands (Nøttvedt et al., 1993; Worsley, 2008). Thick evaporative layers were deposited in the deep Nordkapp Basin that developed during this stage (Worsley, 2008). Changing climatic conditions resulted in sedimentary facies shifts that occurred at the end of the Early Permian and resulted in an increased deposition of mixed terrigenous and marine clastics (Faleide et al., 1984). Re-alignments, intracratonic rifting, uplift and changes in water temperatures led to the deposition of siliceous shales, carbonates and cherts on shelf areas in the Late Permian (Faleide et al., 1984; Nøttvedt et al., 1993, Worsley, 2008).

Regional subsidence in the Barents Sea during the Early–Middle Triassic occurred due to increased sediment supply from the Ural Mountains, the Timan Pechora and the Baltic shield (Faleide et al., 1984, Mørk et al., 1989). Series of thick Triassic sequences that consist of marine shales, siltstones and sandstones were deposited due to the interplay of tectonics and eustatic sea level changes (Faleide et al., 1984; Nøttvedt et al., 1993), while a tensional regime resulted in slight reactivation of pre-existing structures (Berglund et al., 1986). The Late Triassic was a period of continued tectonic quiescence and huge deposition resulted in further subsidence in the western part (Berglund et al., 1986), while non-deposition and erosion prevailed in the eastern and the northern part of the Barents shelf (Nøttvedt et al., 1993).

The Late Triassic–Early Jurassic boundary is characterized by uplift and erosion in the central south, while mainly deltaic sedimentation occurred in the west (Nøttvedt et al., 1993). The deposition of alternating continental and marine sediments was the result of a complex interplay between tectonic subsidence and eustatic sea level changes (Berglund et al., 1986). A relative sea level rise continued from the end of the Early Jurassic towards the Middle Jurassic, which resulted in more marine conditions (Berglund et al., 1986; Nøttvedt et al., 1993). This marine transgression was followed by a regional hiatus in the late Middle Jurassic before repeated tectonic activity, triggered by sinistral shear (Ziegler, 1988), resulted in block faulting and footwall uplifts along the structural highs in the western part (Nøttvedt et al., 1993). Restricted basin circulation during the Late Jurassic led to the development of reducing/anoxic conditions and the deposition of widespread organic rich shales of the Hekkingen Formation (Faleide et al., 1984; Berglund et al., 1986).

Renewed tectonic activity during the Late Jurassic–Early Cretaceous established the present day structural configuration (Gabrielsen et al., 1990). Repeated faulting during the Early Cretaceous

caused the development of deep-seated normal faults, whereas sea level fluctuations resulted in hiatuses and unconformities in the southern Barents Sea (Nøttvedt et al., 1993). Marine shales of the Knurr and Kolje Formations were deposited in basin centers in the western part of the Barents Sea, while erosion of sandy sediments occurred on structural highs (Nøttvedt et al., 1993). A regression during the Barremian–Aptian was followed by a transgression during Aptian–Albian times that resulted in deposition of the Kolmule Formation (Nøttvedt et al., 1993).

The continental break-up of the North Atlantic margin resulted in an opening of the Norwegian–Greenland Sea at the Paleocene/Eocene boundary ca. 55–54 Ma ago. Faleide et al. (2008) reported that pull-apart basins formed in the southwestern Barents Sea due to extension between Norway and Greenland. An overall sea level rise has been indicated by deposition of shales with a uniform thickness across the southwestern Barents Sea in the late Paleocene (Nøttvedt et al., 1993). Sedimentation during the Paleocene–Eocene was followed by an uplift and erosion of the western shelf that has been related to an early phase of sea-floor spreading, while a passive margin developed during the Middle Oligocene (Berglund et al., 1986).

A distinct unconformity that covers the whole shelf can be related to the Northern Hemisphere Glaciation that started 2.6 Ma ago (Faleide et al. 2008). Vorren et al. (1991) considered the deposition of sediment wedges on the Barents Sea margins as a result of repeated uplift and glacial erosions, which resulted in regional tilting of the margin (Faleide et al., 2008).

## 2.2 Source Rocks of the Barents Sea

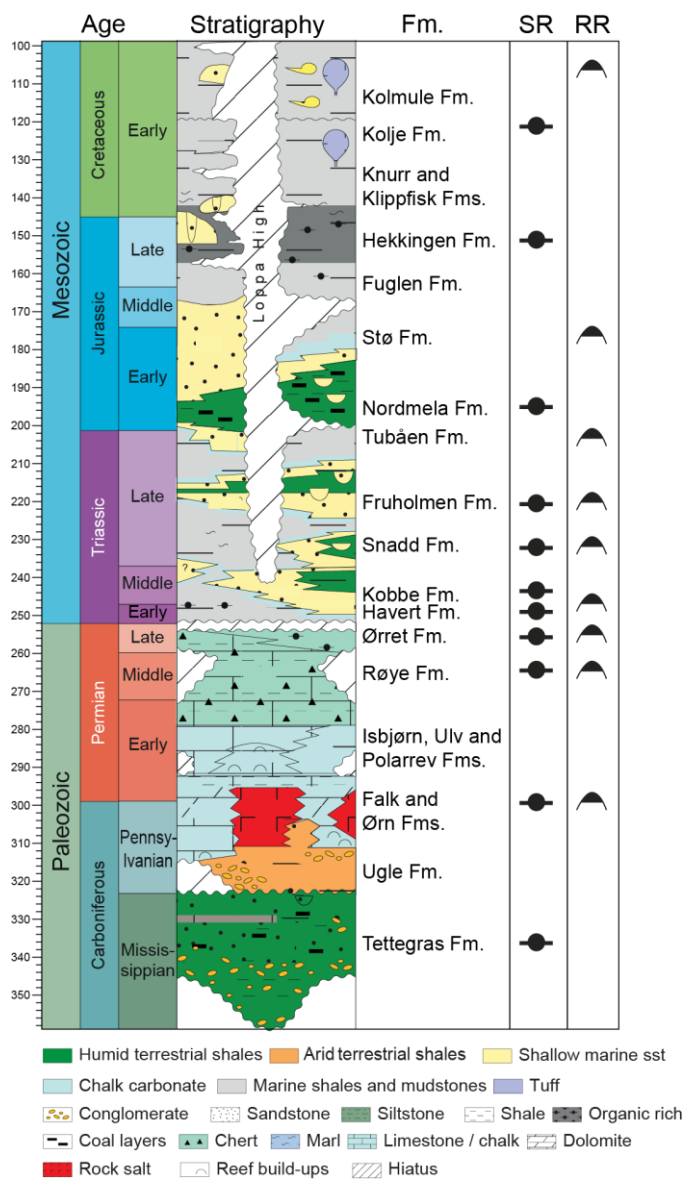
The Barents Sea is considered an overfilled basin with several potential source rock intervals on different stratigraphic levels (Ohm et al., 2008). These are described in the section below.

Carboniferous shales of Visean age with fair to good petroleum potential have been reported on the Finnmark Platform by Pedersen et al. (2005), while Johansen et al. (1993) reported about locally deposited source rocks with very good source quality in restricted basins. The potential to generate oil and gas has been described for the oil prone, coal bearing Lower Carboniferous Tettegras Formation (van Koeverden et al., 2010) that was deposited in deltaic to coastal plains (Ehrenberg et al., 1998). Tettegras Formation deposits in graben structures may serve as important source rock intervals and can furthermore be compared with its equivalent, the Billefjord shales on Svalbard (Abullah et al., 1988; Nøttvedt et al., 1993).

While Lower Permian Brucebyen Beds on Svalbard have been reported with oil potential (Nøttvedt et al., 1993), only poor to moderate potential has been reported for the Lower Permian Evaporites in the Nordkapp Basin (Johansen et al., 1993). Furthermore, Stemmerik and Worsley (2005) mentioned limited source potential for Upper Permian shales and spiculites. The Røye Formation (Fig. 7),

deposited in low-energy, deep shelf to distal marine environments (Larssen et al., 2002), was tested oil prone in the eastern part of the study area (Pedersen et al., 2005). Additional gas potential of thin and organic rich shales of the Upper Permian Ørret Formation, which was deposited in deep dysoxic to anoxic shelf settings, has been reported by Johansen et al. (1993) and Larssen et al. (2002). Further Upper Permian source rocks, however, must also exist in the western part of the study area, i.e. on the Loppa High as the very recent Gotha discovery (7120/1-3) has been reported to be charged from Upper Permian, carbonate to evaporitic source rocks (pers. commun. Pedersen, 2015).

One of the most studied and widely distributed source rock units in the Barents Sea are the Lower–Middle Triassic, marine and organic rich intervals of the Havert, Kobbe and Klappmyss Formations that are equivalent to the Botneheia Formation on Svalbard (Mørk and Bjorøy, 1984; Riis et al., 2008;



Lundschien et al., 2014). The Botneheia Formation mainly consists of shales with kerogen Type II, while Type I kerogen in addition may locally increase the generation potential (Mørk and Bjorøy, 1984; Vigran et al., 2008). While organic rich, Lower–Middle Triassic mudstones in the Hammerfest Basin have been deposited in lagoonal or lacustrine settings, woody fragments may explain a more humid paleo-depositional environment in the Svalis Dome area (Leith et al., 1993). However, the Steinkobbe and Kobbe Formations from the Svalis Dome have recently been described as deposited under restricted marine conditions (Abay et al., 2014). Deposition under fluvio-deltaic, oxic to dysoxic conditions that account for higher amounts of Type III kerogen is suggested for the Kobbe Formation from the Nordkapp Basin and the Bjarmeland Platform.

**Fig. 7:** Lithostratigraphic chart of the SW Barents Sea with indicated source rocks (SR) and reservoir rocks (RR) (modified after Norlex, 2015).

Upper Triassic shales of the Snadd and Fruholmen Formations (Fig. 7) were deposited in transitional environments (Ohm et al., 2008), and show good petroleum generation potential (Pedersen et al., 2005) comparable to the Lower–Middle Triassic shales (Johansen et al., 1993).

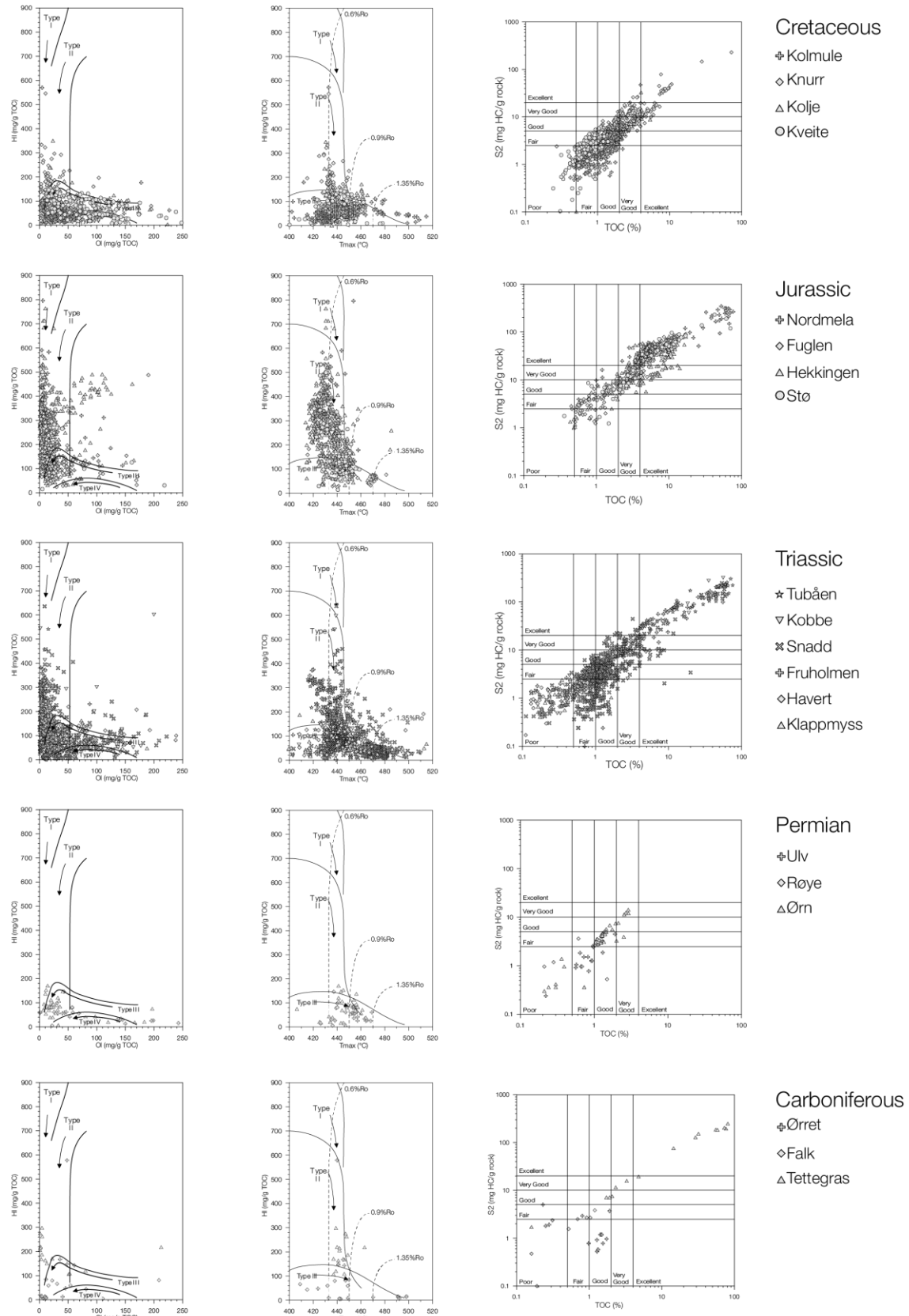
Due to the rapid build-out and westward migration of clastic systems from Novaya Zemlya during Triassic times, organic matter deposited under hypersaline, lagoonal, marine-proximal and marine-distal conditions has been considered by Brekke et al. (2001).

The Lower Jurassic Tubåen and Nordmela Formations are potential source rocks in the western part of the Barents Sea. Both source rock intervals are characterized by mixed terrestrial and marine organic matter input. Due to higher amount of terrestrial derived matter, the Nordmela Formation has the capability to generate more waxy oil compared to e.g. the Upper Jurassic Hekkingen Formation (Ohm et al., 2008; Stewart et al., 1995).

The organic rich shales of the Upper Jurassic Hekkingen Formation (Kimmeridge equivalent) are the most widely distributed source rocks in the western part of the Barents Sea and exhibit a much more uniform facies signature compared to the Triassic source rocks. The Hekkingen Formation contains Type II-III kerogen with excellent potential to generate both oil and gas (Karlsen, 2014). The petroleum potential is locally restricted and highest in the Hammerfest Basin, with immature to early mature levels farther to the east, while gas mature and overmature conditions prevail towards the west and in the Tromsø Basin.

Shales of the Cretaceous Kolje Formation are mature in the western part of the study area (Johansen et al., 1993). Their potential to generate hydrocarbons varies from gas to oil-prone, corresponding to marine Type II to II/III kerogen (Pedersen, 2014).

An overview about geochemical characteristics of the mentioned source rocks based on Rock Eval parameters is provided in Figure 8.



**Fig. 8:** Rock Eval parameters characterizing the kerogen type, the thermal maturity and the hydrocarbon generation potential for source rock samples from the Carboniferous to the Cretaceous (Lerch 2015, unpublished data).

## 2.3 Reservoir Rocks of the Barents Sea

Paleozoic reservoir rocks were mainly deposited as carbonate platforms. Fluctuating sea levels related to Gondwanaland glaciations resulted in a cyclicity of aerial and sub-aerial exposure that had an important impact on the reservoir characterization. Stewart et al. (1995) reported that during sea level lowstands dolomitization and leaching of the carbonates resulted in karst formation that in turn enhanced the porosity. The Late Carboniferous–Early Permian Ørn Formation has been reported with porosities between 15 and 20% (Henriksen et al., 2011a). These shallow water carbonates and dolomites show varying thickness over the shelf whereas thinner, carbonate dominated beds are found on inner platforms that thicken towards distal platforms (Larssen et al., 2002). Silicified limestones of the Upper Permian Røye Formation have been described from the Loppa High and the Finnmark Platform (Larssen et al., 2002). Due to secondary solution processes, these spiculitic cherts are characterized with an average porosity of 22% in well 7128/6-1 on the Finnmark Platform.

The reservoir potential of Triassic rocks has been reported as highly variable (Henriksen et al., 2011a). The variation in reservoir potential can be mainly related to source distance and diagenetic alteration during burial (Doré, 1995). The Lower Triassic Havert Formation has been deposited in offshore to marginal marine environments and shows an effective porosity of around 3%. Improved reservoir quality can be observed in the topmost Havert Formation, which experienced shallower burial and less diagenetic alteration (Henriksen et al., 2011a). The Anisian Kobbe Formation varies in thickness from 170 to 280m and forms high quality reservoirs in the topmost section on the Finnmark Platform (Dalland et al., 1988; Henriksen et al., 2011a). Slightly better reservoir qualities are reported for the distal marine deposited Anisian–Early Norian Snadd Formation (Dalland et al., 1988). Porosities up to 30% have been shown by Henriksen et al. (2011a), who also concluded that the Snadd Formation represents the best reservoir units in the Triassic section. The approximately 200m thick Norian–Rhaetian Fruholmen Formation consist of sandstones, shales and minor coal occurrences that were deposited in fluviodeltaic to floodplain environments (Dalland et al., 1988). Berglund et al. (1986) considered an overall low reservoir potential due to the lack of lateral connection. However, major channelized sand bodies with a maximum thickness of 30m show good reservoir properties (Berglund et al., 1986; Henriksen et al., 2011a). The 50 to 130m thick Rhaetian–Hettangian and upward coarsening Tubåen Formation, which is dominated by sandstones with subordinate shales and minor coals, was deposited on delta front to upper delta plain environments (Dalland et al., 1988). Lateral and widespread distribution resulted in good reservoir potential (Berglund et al., 1986). The Tubåen Formation is characterized by lower and upper sand rich parts that have been deposited in tidal inlets or estuarine environments under high energy. However, interbedded shales in the northwest reflect more distal deposition, while shales and coals in the southwest suggest a more proximal deposition.

The Nordmela Formation was deposited during the Sinemurian–Pliensbachian and consists of very fine to fine grained upward coarsening sandstones. Interbedded siltstone and shaly layers that are dominant in the upper part represent deposition in deltaic embayments (Dalland et al., 1986), while coaly fragments point towards coastal plain environments that have been cut by distributary channels (Stewart et al., 1995). The whole formation is 60–200m thick, with increasing values towards the west (Dalland et al., 1986). The Lower–Middle Jurassic (Pliensbachian–Bajocian) Stø Formation is characterized by a strongly varying sedimentology among the reservoir horizons (Stewart et al., 1995). However, 20–30% porosity and good permeability in the main sandstone bodies and good reservoir continuity have been reported in the Hammerfest Basin (Berglund et al., 1986; Stewart et al., 1995). Cyclic deposition of medium to fine grained, marine sand sheets have been thought to represent a high energy shallow-marine environment, while it has been suggested that upward coarsening sequences display delta front and delta plain repetitions (Berglund et al., 1986; Stewart et al., 1995). The 77–145m thick section is thickest in the SW and thins out towards the east. Interbedded shales and siltstone horizons reflect several sea level fluctuations at the time of depositions (Dalland et al., 1988). The Stø Formation is considered as the most important reservoir rock in the SW-Barents Sea since it holds an estimated volume of 85% of the Norwegian hydrocarbon reserves (Larsen et al., 1993), like for example in the major hydrocarbon discovery of Snøhvit (Johansen et al., 1993).

Cretaceous reservoir intervals of the Neocomian age commonly consist of poorly defined wedges deposited in fan delta environments (Knutsen et al., 2000), have low reservoir quality and appear locally around the Loppa High (Larsen et al., 1993; Doré, 1995). However, petroleum accumulations in Cretaceous sandstones could be found in the east, where these sands are distributed over a greater area. Johansen et al. (1993) for example reported that Neocomian sandstones hold major hydrocarbon reserves east of Novaya Zemlya and in the Kara Sea.

Cenozoic sandstones have been deposited around structural highs, but the distribution and potential of Cenozoic reservoirs is unknown (Johansen et al., 1993). However, Doré (1995) reported minor gas accumulations in sandstones of Oligocene age, thus demonstrating the potential of Cenozoic reservoirs.

## 2.4 Influence of Uplift and Erosion on Petroleum Systems

This paragraph elaborates the effects and implications of several episodes of uplift and erosion, which have been one of the major concerns regarding petroleum systems in the Barents Sea.

### 2.4.1 Cenozoic Uplift and Erosion

As early as 1904 Fridjof Nansen estimated, based on bathymetric measurements, uplift and erosion of nearly 500m on the Barents Sea shelf (Nansen, 1904). Many years later, uplift and erosion were confirmed by several methods described in Vorren et al. (1991) and Doré and Jensen (1996) e.g., vitrinite reflectance, volumetric calculations, diagenetic and geochemical modelling, apatite fission tracks and shale compaction curves. The timing of erosion is crucial to petroleum system studies as it will have significant influence with respect to generation, migration, accumulation and all related processes. Yet, even though the scientific community agrees on exhumation, erosion and re-burial of the Barents Sea, disagreement prevails considering the timing and the extent of the exhumation (Green and Duddy, 2010).

Three major episodes of tectonic related uplift have been described by Cavanagh et al. (2006) who compiled a detailed review of data available until 2006: (1) Late Paleocene (55–50Ma), (2) Oligocene–Miocene (30–15Ma), and (3) Late Pliocene–Pleistocene (2.5–0Ma). The amount of erosion has been suggested ranging between 500 and 1500m for the Hammerfest Basin.

However, Ohm et al. (2008) suggested uplift and erosion in at least three episodes, which occurred at slightly different ages: (1) Paleocene (60Ma), (2) Oligocene (33Ma) and (3) Pliocene – Pleistocene (5Ma). Ohm and co-authors calculated 200m, 600m and 650m of uplift in the Hammerfest Basin for the three stages, respectively, and argued that the latter two can be considered the most significant. Furthermore, two general trends have been described by Ohm et al. (2008): (1) increasing amount of eroded sediment from west to east, and (2) increasing amount of uplift towards the north and northwest, a trend that has also been shown by Nyland et al. (1992). The lowest amount of erosion (0–500m) is observed in the Tromsø Basin, while the western part of the Hammerfest Basin experienced uplift in the range of 500–1000m. The Troms-Finnmark Fault Complex, including the Goliat field (wells 7122/7-1, 7122/7-3, 7122/7-4-S), has been uplifted ca. 1500m. 1000m of uplift has been reported for the Nordkapp Basin and the Finnmark Platform. However, increasing amounts of uplift are shown towards NE Bjarmeland Platform (1500–2000m), while uplift on the Loppa High ranges from 1000m on the southern margin to 2500m on the northern margin and the Stappen High (Ohm et al., 2008).

While Cavanagh et al. (2006) and Ohm et al. (2008) suggested additional exhumation, cooling and erosion initiated by several glacial events, Green and Duddy (2010) state that the glacial influence

during the Pliocene and Pleistocene can be neglected. Furthermore, Green and Duddy (2010) divided the study area in two parts that have individually been affected by exhumation and erosion. Based on apatite fission track analysis and vitrinite reflectance on samples from well 7120/9-2 they concluded two exhumation events in the SW part of the Barents Sea: (1) 2km of uplift in the Early Eocene (40–35Ma), and (2) 1km uplift in the Late Miocene (10–5Ma). Much wider intervals are reported for the northern and north-eastern part of the study area: (1) Early Paleocene – Mid Miocene (60–45Ma), (2) Mid Miocene – Late Miocene (40–35Ma), and (3) Late Miocene – Holocene (10–0Ma) (Green and Duddy, 2010).

A more general trend has been described by Henriksen et al. (2011b), who report on gross uplift values between 1000 and 3000m based on different well data, which, considered separately, demonstrate different trends. Yet, Henriksen et al. (2011b) indicates that net erosion maps based on single values can be uncertain and that the difference in some cases might be as much as 500m.

A more recent study by Baig et al., (2016) calculated average exhumation values ranging from 800 to 1400m in the Hammerfest Basin, 1150 to 1950m on the Loppa High, 1200 to 1400 on the Finnmark Platform, and 1250m to 2400m on the Bjarmeland Platform. Baig et al., (2016) concluded that significant amounts of erosion occurred due to pre-glacial uplift.

In contrast to Green and Duddy (2010), Laberg et al., (2012) reasoned that glacial and fluvio-glacial processes during the last 2.7Ma can be considered the dominant mechanisms that resulted in erosion. Laberg et al. (2012) calculated that between 2.7 and 1.5Ma, 170 to 230m of sediment has been eroded. From 1.5 to 0.7Ma, the total erosion rates were in the range of 330–420m, and in the last 0.7Ma sedimentary cover in the range of 440 to 530m has been eroded.

Different timings of exhumation and variations in the amount of erosion let Dimakis et al. (1998) conclude that amount of glacially induced erosion amounts up to 2/3 of the total erosion, while Rodrigues Duran et al. (2013) on the contrary, decided to define the Oligocene–Miocene erosion (up to 1000m) being more significant than the Pliocene–Pleistocene event (up to 500m of erosion).

It is often ignored that the uplift and erosion on this scale implies that the shelf was, during these periods, dry land. Dimakis et al. (1998) report that the average subaerial exposure in the SW Barents Sea was about 150m. This implicates that meteoric water driven into the basin has the potential for biodegradation (Matapour and Karlsen, 2016).

The correlation of the cited literature implicates that there are still some uncertainties about the timing of the exhumation and the amount of the erosion. It is in agreement that different parts of the Barents Sea experienced faster and/or slower uplift than others, and that the petroleum systems elements have been affected at different times and distinct intensities.

#### 2.4.2 Source Rock Maturation

The thermal maturation of source rocks is commonly assumed to be dependent on both increasing temperature and time in the subsurface. However, temperature is thought to be the most important factor (Tissot et al., 1987). Tissot and Welte (1984) mentioned that maturity is exponential in temperature, but only linear in time. As the process of thermal maturation is an irreversible process, the uplift of source rocks into cooler temperature regimes has a negative impact on further generation of hydrocarbons, albeit Stainforth (2009) showed that expulsion has a different type of kinetics compared to generation, and that expulsion of oil and gas will continue for some time during uplift. Thus, generation from uplifted source rocks will only resume when the temperature exceeds those reached prior to uplift by renewed burial (Doré et al., 2000). However, it has been reported that expulsion from uplifted source rocks can still be active for some time until it finally terminates, and that gas can exsolve from unexpelled oil due to pressure reduction. This gas will provide a driving force for migration. These two processes may give the possibility of reservoir charging even during or after uplift (Doré and Jensen, 1996).

#### 2.4.3 Reservoir Quality

Uplift has a strong negative impact on reservoir quality. Compactional and diagenetic processes such as quartz cementation and authigenic clay mineral formation that occur with increasing burial depth reduce permeability and porosity (Doré and Jensen, 1996). Thus, reservoirs that have been uplifted show poorer reservoir quality than expected at their actual burial depth. However, reservoir enhancements due to fractures, which may facilitate the influx of remigrated or redistributed petroleum during uplift, may have a positive effect on reservoir quality (see next paragraph). Brittle reservoir rocks that have the potential to produce fractures during uplift are quartzites, tightly cemented sandstones and dolomites. Fractures that develop during the removal of overburden thus increase the permeability and porosity and can commonly be observed at shallower depths in the eastern part of the Norwegian Barents shelf as e.g., in well 7128/4-1 on the Finnmark Platform (Doré and Jensen, 1996, and references therein). Furthermore, it may also be possible that changing water chemistry and increased meteoric water flow at shallow depths increase the probability that minerals become unstable (Bjørlykke, 2015).

#### 2.4.4 Seal Properties

In the Hammerfest Basin, numerous dry wells have encountered residual oil saturation and paleo oil columns of up to 200m (Augustson, 1993; Larsen et al., 1993). This suggests massive oil generation in

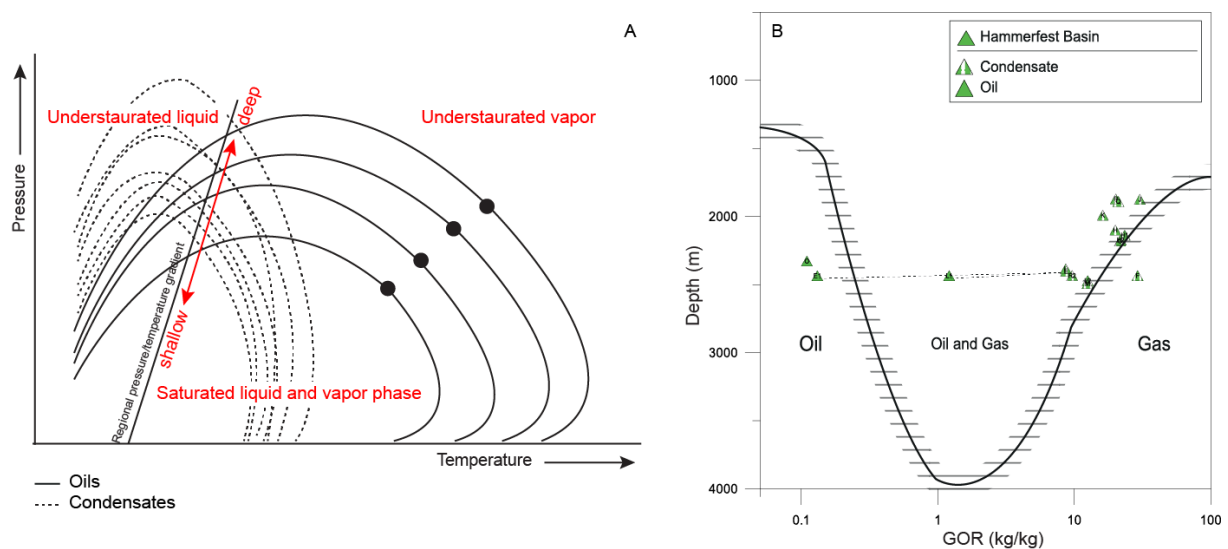
the past. One of the most important questions that arose during the early exploration days was related to: “Where has all the oil gone?” It is commonly assumed that the loss of oil or remigration from the traps is closely linked to the uplift (Nyland et al., 1992; Doré and Jensen, 1996). Cap rock failure due to exhumation and/or reactivation of faults is considered the main reason for loss of petroleum (Larsen et al., 1993; Corcoran and Doré, 2002; Ohm et al., 2008; Henriksen et al. 2011b; Ostanin et al., 2012). The most important properties that influence the seal efficiency are the capillary entry pressure of the seal and its ductility, which changes with pressure and temperature under exhumation (Corcoran and Doré, 2002). It has been reported by Sales (1997) that top seal integrity could be a major risk factor in an exhumed basin, while Doré et al. (2000) emphasized the ductility of seals as the most critical component. Doré and co-authors reported that the possibility of rupturing and leaking is more likely for brittle shales, while ductile shales and evaporites tend to retain their sealing capacity because the latter mentioned are characterized by a more plastic behavior. Processes that influence cap rock properties during uplift include erosion, tectonic deformation, shear failure and hydro fracturing (Corcoran and Doré, 2002). Based on these facts, it is clear that the interaction between seal efficiency, hydrocarbon filling, spilling and leakage is one of the most critical processes considering uplift (Doré and Jensen, 1996). For this reason, Sales (1997) devised a model illustrating three different trap styles that control entrapment of petroleum. He described class 1 traps as gas-containing only, filled to spill, with tight cap rocks and spilling both gas and oil. Class 2 traps contain both oil and gas, and they spill oil and leak gas. Class 3 traps on the other hand are never filled to spill, and are defined as containing mainly oil, due to their ability to leak both oil and gas and spilling neither. The latter trap remains an oil trap if the rate of supply of petroleum exceeds the rate of loss, i.e. this is a dynamic trap. In contrast to older views, which suggested that only a thick cap rock is a good cap rock, studies by Karlsen and Skeie (2006) and Ohm et al. (2008) suggest that the cap rock does not have to be thick as long as it can hold back the oil. Thus, it is important to remember that some of the major oil provinces in the USA and in the Middle East represent uplifted basins. For these reasons, it seems wrong to treat uplift in the Barents Sea only in a negative way.

#### 2.4.5 Migration, Remigration and Changes in PVT Conditions

Considering the three different trap classes discussed by Sales (1997), it is equally important to remember the concomitant changes in reservoirized petroleum that occur due to pressure-volume-temperature (PVT) changes. Because PVT conditions in the subsurface change dramatically with uplift and erosion, the amount of uplift is of greatest importance for petroleum system analysis. Two important processes should be mentioned in this context: (1) phase fractionation of petroleum where gas separates from the saturated liquid, and (2) the expansion of gas of both the already present gas and the separated gas (cf. Karlsen and Skeie, 2006). Gussow (1954) mentioned that a trap buried to 1890m is capable of holding 200 times more gas than under atmospheric conditions. A standard North

Sea oil (reservoired at 40Mpa and 105°C) consists of up to 50mol% methane with a total weight of 11% (England et al., 1987). Hence, the volume of gas and LHC compounds increase drastically when a reservoir is uplifted to shallower depths. As already mentioned under paragraph 2.4.1, the amount of uplift and erosion are discussed controversially, that in could in turn affect migration, remigration and fractionation processes.

In Paper 1 (page 170), it has wrongly been stated that “If the reservoir reaches shallower depths (e.g., due to exhumation), gaseous compounds and LHC will dissolve and form a two-phase fluid.” The correct statement should be: “If the reservoir reaches shallower depths (e.g., due to exhumation), gaseous compounds and LHC will exsolve and form a two-phase fluid”. In order to support this statement, Figure XXX has been prepared. Figure 9a shows a representative phase envelope diagram for oils and condensates from the Hammerfest Basin adopted from di Primio et al. (1996). The diagram indicates that with decreasing temperature and pressure (along an assumed regional pressure and temperature trend), the phase envelope of both the liquid and the gaseous/condensate phase decrease (di Primio et al., 1996). It is shown that the critical point of the saturated liquid phase moves towards lower temperatures and pressures, leading finally to exsolution of gaseous compounds. The liquid phase thus increases in density, but loses its low molecular weight compounds. A reduction in the GOR can be observed that leads to undersaturation of the liquid phase (see Fig. 9b). The novel generated gaseous phase however, is characterized by a lower density than its parent liquid phase that is related to enrichment of low molecular compounds. In turn, an increase in the GOR compared to the parent liquid phase can be observed (see Fig. 9). The modification of physical subsurface parameters (pressure, temperature) and differences in physical properties of the liquid petroleum and the segregated vapor phase (density, viscosity) may enhance differential migration and entrapment (di Primio et al., 1996; Gussow, 1954; Silverman; 1965)



**Fig. 9 (previous page):** (a) Phase envelope of oils and condensates from the Hammerfest Basin (modified after di Primio et al., 1996), and (b) a diagram indicating the GOR's for selected samples from the Hammerfest Basin (modified after Lerch et al., 2016a).

As discussed earlier, it has been shown that residual oil columns are found under present gas/condensate columns in the Hammerfest Basin (Augustson, 1993), while traps holding liquid petroleum are mainly located in the up-dip direction from the basin center. Observations for the same phenomena in both the USA and the Arabian Gulf region inspired Gussow (1954) to discuss “the differential entrapment of oil and gas”, and Silverman (1965) likewise devised the model for “migration and segregation of oil and gas”, where structures in up-dip regions mainly hold oil and structures located down-dip mainly hold gas accumulations. Residual oil found below the present spill point implicates that most gas/condensate bearing structures today have been saturated with oil in the past. For the Barents Sea, Ohm et al. (2008) postulated that uplift induced remigration of oil from the mid part of the Hammerfest Basin towards the Goliat area occurred (Fig. 6).

Two likely scenarios may explain the current distribution of petroleum in the Hammerfest Basin and adjacent areas.

(1) Petroleum reservoir under supercritical conditions is referred to as a single phase, where all gas is dissolved in the oil and vice versa. Due to uplift and changes in PVT conditions, the gas starts to exsolve from the liquid when the bubble point is reached, resulting in a two phase system (Fig. 9a). The coincident expansion of the gas cap leads to displacement of oil from a trap by pushing the oil below spill point, initiating a remigration towards up-dip regions. The trap is thus only capable of holding gaseous hydrocarbons and can be referred as class 1 after the definition of Sales (1997).

(2) Phase fractionation in liquid reservoir petroleum due to degassing can lead to a pressure increase in the trap. If the cap rock is brittle, as in the case of the Goliat discovery, (Ohm et al., 2008), the gaseous phase can migrate through fractures and is lost from the trap. In the best case scenario, the remigrated/dysmigrated phase moves to shallower parts in the stratigraphic column where it is trapped again. However, the pore size in the fractured cap rock tends to be too small to allow bigger molecules to migrate through the pores, resulting in a liquid petroleum phase that is depleted in light components. These traps, according to Sales (1997), would be defined as class 2 or class 3.

The fundamental processes of phase fractionation, remigration and dismigration in fill-spill scenarios should be kept in mind when considering petroleum mixtures, as discussed in Paper1 and Paper2.

#### 2.4.6 Bacterial Alteration

It has been reported by Wilhelms et al. (2001) that reservoired petroleums in the uplifted Barents Sea have not been exposed to biodegradation. Wilhelms et al. (2001) suggested that reservoirs, which have been buried to temperatures exceeding 90°C, have been sterilized against degradation processes, even if uplifted afterwards. However, petroleums used in this study show a quite variable degree of biodegradation that, in some cases, is suggested to have occurred post-uplift (Paper 1, Paper 2). A possible way to explain biodegradation is to relate the microbial alteration to the uplift and several glacial stages. Generally, continuous subsidence of a basin results in an updip water flow towards the basin margins. However, if the basin is uplifted, the hydraulic system is reversed, leading to a water flow that is directed towards the basin center (Doré et al., 2002). In addition to uplift and erosion, the Barents Shelf was exposed to several glacial and interglacial cycles during the Pliocene–Pleistocene, where lower sea-levels led to a more elevated groundwater table onshore. Bjørlykke (2015) showed that meteoric water is able to intrude into sedimentary basins as much as 40 times the height of the groundwater table due to an increase in the hydrodynamic head. Fresh meteoric water usually contains increased amounts of dissolved oxygen and so is able to carry microbes. The renewed introduction of microbes into a pasteurized reservoir (Wilhelms et al., 2001) would thus enhance the chance of (renewed) bacterial biodegradation. This mechanism has been proposed by Karlsen et al. (2004) and Karlsen and Skeie (2006) for biodegraded petroleums found in the Norwegian Sea and is discussed in Paper 1 for the shallower reservoired Goliat oils (Paper 1).



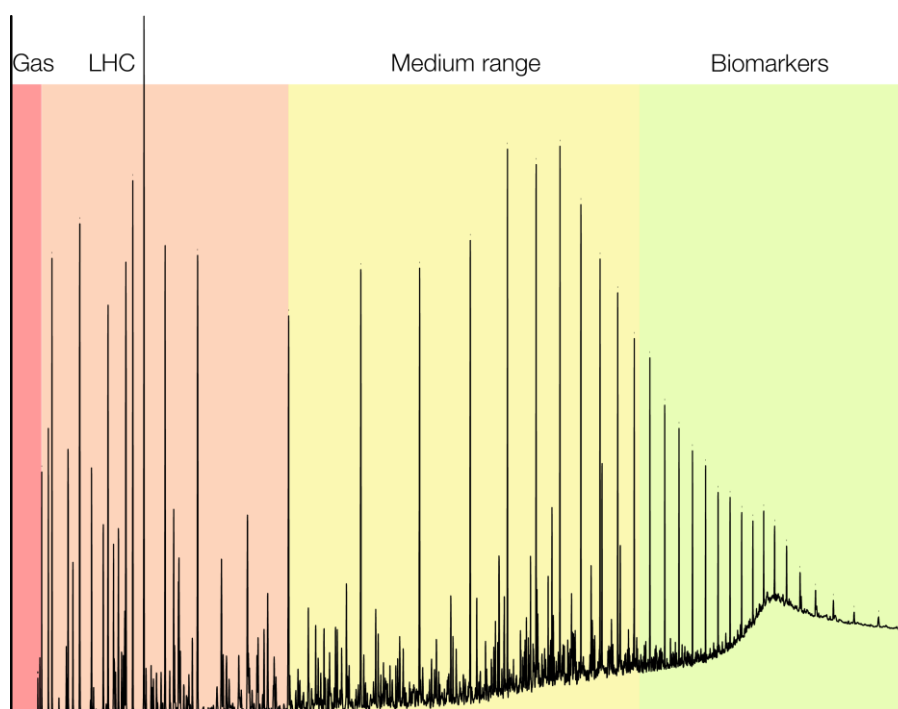
### 3 Results and Implications

The main idea behind this Ph.D. project was the geochemical characterization of the petroleum systems in the Barents Sea. The present database was utilized to liberate new information, and define the data using modern principles of interpretation. One objective, furthermore, was to use the applied petroleum correlation techniques in order to map out regional petroleum systems.

It has been shown in earlier studies that some petroleum systems, especially those from the Hammerfest Basin, have been altered by fractionation e.g., loss or depletion of light hydrocarbon compounds and that condensates are depleted in biomarker compounds. Hence, correlation based on just one compound class may lead to misinterpretations, due to the lack of information of the “whole picture” (Fig. 10). In addition, due to the presence of multiple source rocks, several uplift, burial and erosion events, it has been considered likely that some of the petroleum systems in the database do not reflect their original composition and geochemical signature. In order to obtain a better regional correlation between the samples in the database, a method had to be chosen that allows integration of all samples based on a common ground.

Therefore, the study in hand investigated hydrocarbon fractions i.e. light hydrocarbons ( $C_4$ – $C_8$ ), medium range hydrocarbons ( $C_{10}$ – $C_{18}$ ) and biomarker range compounds ( $C_{20+}$ ) (Fig. 10). This was done in order to systematically “isolate” maturity, alteration and facies signatures of the respective

compound fraction and create a unique “fingerprint” of each sample. It has been suggested that such an application would allow a better understanding of the complex filling history of traps by several phases of oil and condensates, even from separate source rocks. Therefore, it is believed that such a systematic approach, investigating the petroleum section by section, is the only way forward to be able to decipher the petroleum systems in the Barents Sea.



**Fig. 10:** GC-FID whole oil chromatogram showing the different compound fractions that have been analyzed: LHC ( $C_4$ – $C_8$ ), medium range ( $C_{10}$ – $C_{20}$ ) and biomarker range compounds ( $C_{20+}$ ). Gas data were unfortunately not available in this study. Yet, investigation of gases is suggested for future studies (see paragraph 4.1).

The approach of analyzing fraction by fraction for effective fingerprinting of the samples has been the backbone of this thesis. For this reason, Paper 1 discusses alteration, migration and maturity trends based on light hydrocarbon compounds, while Paper 2 investigates maturity, mixing and alteration trends based on the medium range and biomarker range compounds. Paper 3 focusses on the ages, the depositional environments and the organic matter input of the inferred source rocks.

In addition to the routinely used geochemical markers and interpretational diagrams, multivariate statistical analysis has been applied as an auxiliary tool for petroleum family classification. Multivariate statistical methods have been used to extract some geochemical information that may not have been detected in the dataset using molecular based ratios only (cf. Christie et al. 1984). Christie et al. (1984) described the application of multivariate statistical methods useful in order to obtain geographical trends in correlation studies.

### 3.1 Paper 1

#### Regional Petroleum Alteration Trends in Barents Sea Oils and Condensates as a clue to migration regimes and processes

Lerch, B., Karlsen, D.A., Abay, T.B., Duggan, D., Seland, R. and Backer-Owe, K., 2016. AAPG Bulletin, 100, 165-190.

In this study, light hydrocarbon (LHC) compounds in the range  $C_4$ – $C_8$  have been analyzed for 45 samples (see Table 2 in Paper 1). The emphasis of this paper was to investigate the thermal maturity, secondary alteration effects such as evaporative fractionation, water-washing and biodegradation as well as to determine the organic facies of the LHC. This first step was done in order to draw conclusions about migration and alteration regimes in the study area.

#### 3.1.1 Findings

- ✓ Phase fractionation signatures have been found in condensates and oils in the Hammerfest Basin only. High aromaticity values for condensates suggest repeated gas-stripping events. Fractionated oils are found under present gas/condensate caps that can be linked to uplift induced separation of a single phase into two phase system, or alternatively in relation to migration induced phase fractionation. The presence of different petroleum phases can be used to draw conclusions about the trap classes and possible remigration initiated by fill-spill processes.
- ✓ Greater amounts of the water soluble aromatic compounds like toluene and benzene in samples from the Tromsø Basin, with slightly decreasing amounts towards the central part of the Hammerfest Basin suggest locally derived LHC. Yet, samples that are depleted in these compounds are proposed to have migrated over long distances. The depletion of water soluble LHC compounds thus supports the suggested fill-spill process. It is tentatively suggested that an oil migration network extends from the central part of the Hammerfest Basin towards southern margin and with possible extension towards the Måsøy-Nysleppen Fault Complex.
- ✓ Biodegradation is mainly found in petroleums collected from reservoirs that are located on elevated basin margins. It is, for this reason assumed that biodegradation is closely linked to uplift and repeated glacial events that favored the intrusion of meteoric water into the basin.
- ✓ Correlation of LHC parameters with compounds in the  $C_{15+}$  range indicated mixing of older paleo petroleums with more recent charges. It is suggested that the fresh, unaltered LHC

signature in sample B2 (7120/1-2) from the southern margin of the Loppa High indicates a recent migrated and unaltered phase, which would support a live petroleum system in the area.

- ✓ A decreasing W-E maturity trend could be established from the Tromsø Basin towards the Måsøy-Nysleppen Fault Complex, whereas slightly higher maturity values have been recorded for samples from the Finnmark Platform and the Nordkapp Basin. Organic facies parameters, in general reveal generation from source rocks containing kerogen of Type II–III, while LHC compounds in samples from the Loppa High probably originated from Type II kerogen.

### 3.1.2 Implications

LHC compounds are the most easily lost and altered compounds in petroleum. Even so, the study showed that they can be used for correlation and alteration purposes. The recognition of fill-spill induced remigration of liquid petroleum away from the deeper, central parts of the basin and towards the elevated basin margins, implicates a distinct migration network in the Hammerfest Basin. Thus, it is likely that more oil discoveries will be made in structurally higher areas.

It follows that negative aspects associated with uplift and erosion do not automatically imply negative exploration results, as long as the cap-rock is able to hold back the oil phase as reported for the Goliat discovery.

LHC correlation techniques should be applied in multiple source rock basins like the Barents Sea, as they provide a powerful means in order to investigate petroleum blends. Furthermore, they allow correlation between oils and high GOR condensate that is often not possible when considering biomarker range compounds ( $C_{20+}$ ), as condensates are commonly depleted in this range.

Generation and expulsion of petroleum from several source rock intervals increase the probability of petroleum mixtures and complicate petroleum system analysis. Still, integration of geochemical data into basin modelling studies could enhance the knowledge about expulsion and charging histories when considering the different thermal maturities and alteration signatures of the different compound classes. Investigation of LHC compounds can be used to predict trap classes defined by Sales (1997), and in combination with regional geology help to anticipate the occurrences of liquid petroleum.

### 3.2 Paper 2

Organic geochemistry of Barents Sea petroleum: Thermal maturity and alteration and mixing processes in oils and condensates.

Lerch, B., Karlsen, D.A., Matapour, Z., Seland, R. and Backer-Owe, K., 2016. Journal of Petroleum Geology, 39, 125-147.

The saturated and aromatic compound fractions in the range  $C_{14}$ – $C_{18}$  and biomarker range ( $C_{20+}$ ) for 50 oil and condensate samples were analyzed. The purpose was to delineate the thermal maturity and alteration signatures, and to compare these with results obtained from the LHC analysis (Paper1) to investigate mixing processes.

#### 3.2.1 Findings

- ✓ Thermal maturity data indicate petroleum generation at maturity levels ranging from the early- to late-oil/condensate window, corresponding to calculated vitrinite reflection values between 0.7%Rc and 1.9%Rc. Two maturation traits have been found in most of the samples, which may suggest mixing of petroleum phases: a  $C_{20+}$  fraction that is suggested to represent a paleo petroleum charge, and a  $C_{20-}$  fraction that possibly represents a more recent charge.
- ✓ Several biodegradation signatures which encompass depletion of saturated  $C_{15-}$  hydrocarbons, almost complete removal of *n*-alkanes, enhanced Pr/*n*- $C_{17}$  and Ph/*n*- $C_{18}$  values, occurrence of 25-norhopanes and reverse distribution of methylated naphthalenes isomers have been found. Presence of unaltered LHC compounds that occur together with biodegradation signatures can be seen as additional evidence for petroleum mixtures.
- ✓ A characteristic “triplet-terpane-pattern” on the *m/z* 191 has been found to effectively discriminate petroleum generated from Permian/Triassic, and petroleum generated from Jurassic source rocks. While sparse  $C_{24}$  tetracyclic (TET) and greater abundances of  $C_{26}$  tricyclic terpanes (TT) characterize Permian/Triassic petroleum, Jurassic derived petroleum are identified by higher  $C_{24}$ TET and lower abundances of  $C_{26}$ TT.
- ✓ Condensates, in general, can arise from (i) higher generation temperatures, and/or (ii) phase fractionation. The condensates in this study, however, indicate higher generation temperatures than the oils and seem to be affected by evaporative fractionation processes. Because condensates have very low concentrations of biomarker compounds in the  $C_{20+}$  fraction that is related to fractionation effects or generation at elevated temperatures, it was found useful to

apply medium volatility aromatic compounds for maturity indication, when correlating oils with condensates. Because of the lower boiling points and higher vapor pressure of compounds in the medium volatility range, these compounds tend to be enriched in the condensate phase.

### 3.2.2 Implications

Results from this study are interpreted in the context of results obtained from the LHC analysis conducted in Paper 1. It was found in this work that most samples are characterized by two different maturity signatures: (i) A  $C_{20+}$  “paleo-oil” signature that represents an older charge, and (ii) a  $C_{20-}$  signature that is suggested to reflect a more recent influx.

Mixtures or blends of petroleums that are characterized by contrasting maturity signatures imply several generations of petroleums, which points towards several “critical moments” (cf. Magoon and Dow, 1994). The presence of petroleum blends has to be taken into account when considering basin modelling studies, as recognition of blends imply a more complicated reservoir filling model. Furthermore, for volumetric calculations, it is relevant to consider oil and gas contribution from more than one source rock horizon. Thus, this information is of significant value for models dealing with migration pathways and also the time of generation, expulsion and accumulation of oil and gas. However, in some cases it may be possible that the maturity signature also shows a regular maturity sequence in which the source rocks expel more mature and lighter hydrocarbons with increasing burial depth.

Microbial alteration of petroleums has been excluded for the Barents Sea previously. However, the present study found evidence of biodegraded petroleums to varying degrees. Biodegraded petroleums have only been found on elevated basin margins, in the eastern part of the Hammerfest Basin and one well on the Loppa High. It could be suggested that in most cases where microbial alteration has been recorded, the paleo-oil mixed with a later arrived, non-degraded charge, hence indicating at least generation and expulsion of hydrocarbons from two different source rocks, moreover at two different “critical moments”.

Two rough maturation trends based on the maturity data could be observed: (i) decreasing maturity from the western part of the Hammerfest Basin towards the Måsøy-Nysleppen Fault Complex, with slightly increasing maturities towards the Finnmark Platform, and (ii) a North-South trend in the Hammerfest Basin with higher maturities on the southern margin and lower maturities on the northern margin. Because the Snøhvit oils and the oils from the shallower Goliat reservoir show equal maturities, it is suggested that long-distance migration occurred from the greater Snøhvit area towards the Goliat area, which is in agreement with observations obtained in Paper1.

### 3.3 Paper 3

Depositional environment & age determination for inferred source rocks from Barents Sea petroleum.

Lerch, B., Karlsen, D.A., Seland, R. and Backer-Owe, K., 2016. Journal of Petroleum Geoscience, Published Online First, doi: 10.1144/petgeo2016-039

The main objective of this study was to infer the ages and the depositional environments of the source rocks that generated the petroleum in the present database. Therefore, 50 oil and condensate samples have been examined based on biomarkers that are commonly used to infer the organic matter input and depositional environments. Based on geochemical characteristics, it was possible to categorize the samples roughly into four petroleum families. Furthermore, multivariate statistical analysis was carried out to validate the classification. This paper focusses only on the  $C_{15+}$  fraction, so the characteristics of the  $C_{15-}$  fraction have not been considered.

#### 3.3.1 Findings

- ✓ Based on geochemical results and multivariate statistical analysis it was possible to classify the investigated samples into four families: (1) Family A: Permian/Triassic sourced petroleum, (2) Family B: Carboniferous sourced petroleum, (3) Family C: Jurassic sourced petroleum, and (4) Family D: condensates generated from late- to gas-mature Triassic and Jurassic source rocks. Sourcing from Cretaceous source rocks could be excluded for the  $C_{15+}$  compounds. Yet, in the westernmost area that has not been examined in this study, a Cretaceous contribution could be possible, as even the Jurassic section is overmature west of the Loppa High in the Bjørnøya Fault Complex.
- ✓ Advanced investigation of the discussed “triplet-terpane-pattern” (Paper2) showed that the amount of  $C_{24}$  tetracyclic terpanes (TET) could not be linked to a specific environment. Deposition under transitional conditions that reflect lacustrine to marine characteristics is considered likely. However, compounds that specifically indicate deposition in lacustrine conditions as e.g.,  $\beta$ -carotane and a dominant abundance of  $C_{28}$  steranes could not be confirmed. It is proposed that the distribution of  $C_{24}$ TET can be used as an unconventional age indicator in the present database. It may represent the precursor compounds in organisms that lived on the Barents Shelf during Permian/Triassic deposition. Yet, the  $C_{24}$ TET might be used to indicate paralic source rocks that could have been deposited during progradation of Triassic depositional systems that proceeded from SW towards the NE.

- ✓ Isotope values and age related parameters showed that mixing of petroleums may play an important role, as e.g. bisnorhopane, a typical Jurassic marker, has been found in 82% of the samples within the database. While in a few cases the isotopes and age related compounds (e.g. for samples B1 and B2) indicated a Paleozoic origin, this age could not be determined by the tricyclic terpanes that have been used to distinguish Jurassic and pre-Jurassic samples in the database. Thus, it might be speculated that the later arrived charge was able to dilute the biomarker distribution of the primary charge, but not the  $\delta^{13}\text{C}$  values.
- ✓ Inferred depositional environments were found to vary from marine, shallow marine, deltaic, lacustrine to terrestrial dominated conditions, while redox conditions range from anoxic, reducing to oxic. The majority of the samples are indicated to be generated from Type II–III kerogen, while some source rocks may have had additional input of Type I kerogen organic matter.
- ✓ Due to the enrichment of lighter boiling point compounds in the vapor phase, condensates often showed a strong terrestrial signature comparable to samples from the Finnmark Platform that have been generated from the Lower Carboniferous Tettegras Formation.

### 3.3.2 Implications

The findings of this study illustrate the distribution of petroleums with regard to their age. It is suggested that Jurassic oils mainly remigrated from the central part of the Hammerfest Basin towards its southern and northern basin margins. Paleozoic and Triassic oils found on the Loppa High implies that stable platform highs are capable of hosting oils older than Jurassic. It is suggested that reservoirs on the Loppa High have been shielded from Jurassic influx. Thus, it is anticipated that more Paleozoic/Triassic petroleums will be found on the Loppa High or stable platforms in general.

However, occurrence of Triassic petroleum in the deeper Goliat reservoir on the southern margin of the Hammerfest Basin implies that even Triassic petroleum migrated towards the margins. Thus, it may be speculated that more Triassic sourced petroleums will be found in deeper strata in the south.

Since condensates constitute a major hydrocarbon phase in the database, there was a special need to focus on their geochemical signatures. Due to the enrichment of lighter boiling point compounds in the vapor phase, condensates are often misidentified in respect to organic facies when studied together with oils. The study showed that condensates are suggested being expelled from a terrestrial source rock, because they appeared to have similar characteristics to the samples from the Finnmark Platform, which have their possible origin in the Lower Carboniferous Tettegras Formation. However,

systematic evaluation of the three hydrocarbon compound classes overcomes this issue. Even integration in multivariate statistical analysis was possible by considering the geochemical features.

Assessment of age specific parameters can be quite challenging in petroleum mixtures. Inconsistent age classifications or missing data in this study underline this fact. However, geochemical characteristics such as the distribution of tri and tetracyclic terpane compounds served as unconventional age markers for Permian and Triassic petroleum. It is suggested that the specific distribution probably reflects the basin wide occurrence of the precursor compounds during deposition.

### 3.4 Samples and Analytical Procedures

Fifty liquid hydrocarbon samples (condensates and oils) were collected in the southwestern Barents Sea from the mid 1980's to 2008. The samples have previously been analyzed by different geochemical laboratories. Even though all laboratories followed the Norwegian Industry Guide to Organic Geochemical Analysis (Weiss et al., 2000), there was a demand to re-analyze the samples in one laboratory only to obtain comparable data. This analysis was done by Applied Petroleum Technology (APT) AS, Kjeller, Norway and the dataset was kindly provided by NORECO ASA. Despite comprehensive analysis, data for some samples i.e. isotope data were missing. For completion of the dataset, some data were taken from geochemical reports available at the Norwegian Petroleum Directorate Factpages (Norwegian Petroleum Directorate, 2014). The analytical procedures applied are described below.

#### *Gas Chromatography –Flame Ionization Detector (GC-FID)*

Whole oil analysis was carried out on an Agilent 7890A instrument equipped with a HP PONA column (50m x 0.2mm i.d., film thickness 0.5µm). The temperature program applied was: 30°C (10min hold) to 60°C at 2°C/min, then to 130°C at 2°C/min, followed by 4°C/min to 320°C (25min hold).

#### *Gas Chromatography - Mass Spectrometry (GC-MS)*

GC-MS of saturated and aromatic fractions was carried out on a Micromass ProSpec high resolution instrument equipped with a CP-Sil-5 CB-MS column (60m x 0.25mm i.d., film thickness 0.25µm). The temperature program used was: 50°C (1min hold) to 120°C at 20°C/min, then to 320°C (20min hold) at 2°C/min. Data was acquired using Selected Ion Recording (SIR) mode. Saturates were

monitored using  $m/z$  177, 191, 217 and 218, while aromatics were monitored using  $m/z$  142, 156, 170, 178, 184, 192, 198, 231 and 253.

GC-MS-MS for aliphatic compounds was done on a Thermo Scientific TSQ Quantum instrument. The collision energy is 15eV with Argon as the collision gas at a pressure of 1.0mTorr. The column used is a FactorFour VF-1ms (60m x 0.25mm i.d., film thickness 0.25 $\mu$ m). Transitions monitored are the following:  $m/z$  358  $\rightarrow$  217, 372  $\rightarrow$  217, 386  $\rightarrow$  217, 400  $\rightarrow$  217, 414  $\rightarrow$  217.

Stable isotope values of selected samples were included in the database and collected from different geochemical reports available at the Norwegian Petroleum Directorate Factpages (2014).

For selected samples,  $\delta^{13}\text{C}$  isotopes were included in the dataset. The remaining data have been found in online available geochemical reports from the NPD.

## 4 Concluding Remarks – Petroleum System Implications

The present thesis was conducted in order to improve the understanding of the petroleum systems in the SW Barents Sea. A database containing geochemical information for 50 petroleum samples has been the foundation of the study. It early has been suggested that many petroleums in the Barents Sea are considered as petroleum blends or mixtures. Attempts in the past to link individual oils and condensates directly to one type of source rock, or to propose source rock maturity based on single oil or condensate samples have often been complicated. The reasons for these circumstances are closely related to the multiple source rocks in the basin, i.e. several “critical moments” and the multiple uplift and burial events. Thus, the following research questions have been addressed:

- 1) What are the geochemical characteristics of the present petroleum systems?
- 2) Are there evidences for blended or mixed petroleums? Is it possible to decipher the blended signatures?
- 3) What are the present petroleum systems and where are they to be found? Is it possible to delineate geographical boundaries?

In the beginning of this Ph.D. thesis it has been suggested that the main focus should be placed on the evaluation of different hydrocarbon compound classes. The idea behind it was that possible variations

in thermal maturity or alteration signatures among the various fractions can be utilized to discern petroleum blends. Despite the fact that even a single compound class, e.g. the  $C_{20+}$  biomarker range fraction can be used to obtain information about the thermal maturity or the depositional facies, it is beneficial in a multi-source rock basin if the derived interpretations are supported by other compound classes. Therefore, the necessity to elaborate the geochemical information based on the three compound classes is vital to fully understand the “history” of each sample. It followed that the achievement of this goal is realized by investigation of the different compound classes: (1) the light hydrocarbon compounds  $C_4$ – $C_8$ , (2) the medium volatility compounds  $C_{10}$ – $C_{20}$ , and (3) the  $C_{20+}$  biomarker range compounds.

Fifty petroleum samples have been geochemically analyzed “fraction by fraction” in order to generate a complete fingerprint of each sample for correlation purposes. Due to this “liberation” of the data it was possible to map out the petroleum systems in the study area. The geochemical characteristics allowed us to deduce the thermal maturity, the degree of alteration (due to migration, biodegradation and fractionation), and the source depositional facies. Such an approach may be useful for other multi-source rock basins, the circum Arctic region and particularly for the Russian part of the Barents Sea. A study by He et al. (2012) for example found petroleums generated from Devonian to Jurassic source rocks. Based on geochemical and statistical results, six petroleum families have been classified. Yet, the study was conducted using biomarker and diamondoid data, and it is believed that a more detailed insight into mixing and alteration processes can be obtained following the approach applied in this study.

Oil-oil and oil-condensate correlation has been used to identify and group samples into genetic families by applying geochemical parameters. Thus, it was possible to establish and determine regional relationships and distributions of petroleum families in the Barents Sea. It has been feasible to compare samples among the families and identify or distinguish areas with families that have been generated from a single source rock from those, which have possible contributions from several sources.

The concept of investigating the samples “fraction by fraction” allowed us to conclude that several oils in the region are petroleum blends originating from more than one source rock unit. In particular, when comparing the  $C_{20-}$  and the  $C_{20+}$  fractions, two different generations of petroleum could be determined. It is suggested that during repeated episodes of uplift, residual oil from earlier migration events will remain in a trap as immobile oil until a later charge arrives during renewed burial, resulting in a petroleum blend. Yet, it seems that older charges in structurally complex regions and platforms were better preserved than for example in the central part of the Hammerfest Basin, where the more recent arrived charges (oil or condensate) tend to dominate. Thus, it seems likely that a more complex picture emerges concerning oils and condensates in traps in the region. This is likely caused by a more

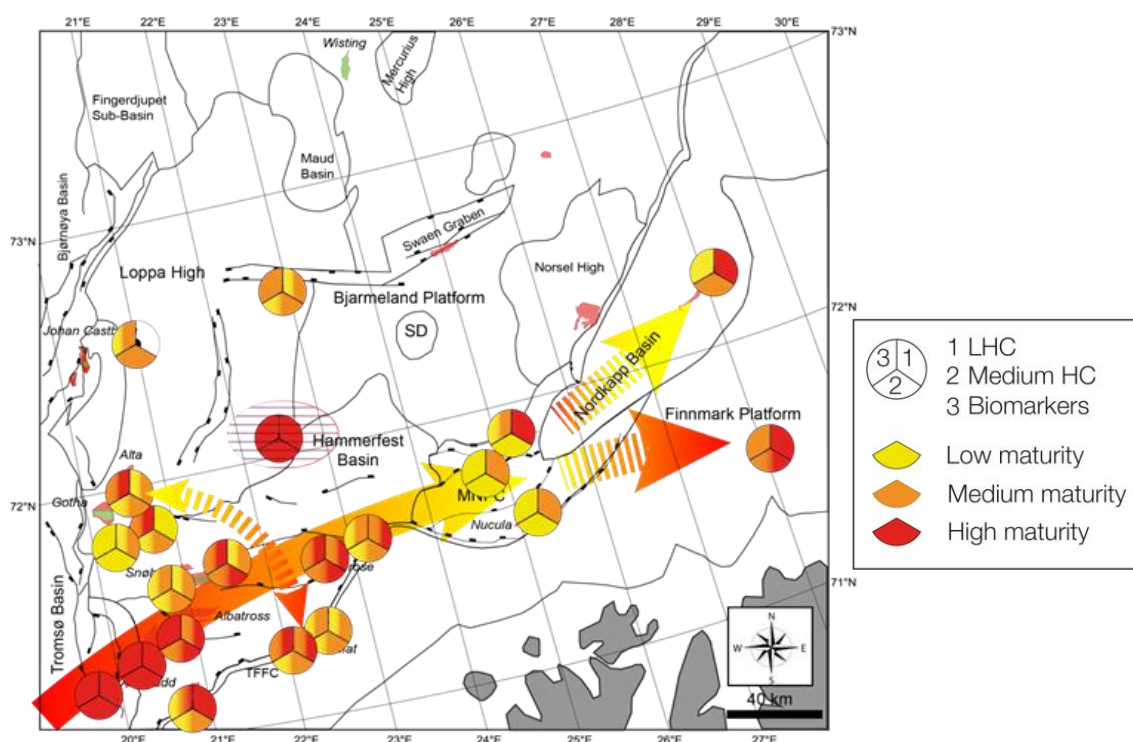
complicated than anticipated migration and remigration pattern in this multi-source rock basin, compared to other regions on the Norwegian Continental Shelf. A much higher preservation potential is assumed for platform areas such as the Loppa High with the very recent Gotha and Alta discoveries, even though full leakage has been reported for the Obelix well 7220/6-1 farther north on the platform. Yet, reservoirs with “bad” cap rocks, e.g., the shallower Goliat discovery along the periphery of the basin seem to be better targets for oil. Variations in thermal maturities and alteration signatures among the three different compound classes investigated concluded a paleo  $C_{20+}$  fraction and a later  $C_{20-}$  charge. These petroleum mixtures confirmed the existence of several critical moments.

However, even though the majority of the samples are characterized by different thermal maturities in their respective compound fractions (Fig. 11), not all samples may represent petroleum blends. As with increasing thermal maturity the amount of expelled LHC increases as well (see Fig. 1), the maturity sequence as observed in sample AB from the 7228/7-1 A well in the Nordkapp Basin may represent a naturally occurring maturity signature. Therefore, care must be taken not to misinterpret the different maturity signatures.

Two regional maturation traits have been found investigating the thermal maturity of the petroleum: (1) decreasing maturity from the western towards the eastern part, with slightly increasing maturities on the Finnmark Platform and the Nordkapp Basin (Fig. 11), and (2) a north-south maturity in the Hammerfest Basin, where higher maturities could be observed on the southern margin. The study could show that towards the east, the  $C_{20+}$  fraction is slightly less mature than the  $C_{20-}$  fraction, indicating a more mature, later charge (Fig. 11). However, on the Loppa High and in some samples from the Hammerfest Basin, the  $C_{20-}$  fraction is less mature than the  $C_{20+}$  fraction. This implies that only the gaseous and/or the LHC compounds have been able to migrate on to the Loppa High, while the  $C_{20+}$  maturity signature represents the “shielded” paleo-oil, or that the  $C_{20-}$  fraction has been generated from a local, but different source rock than the  $C_{20+}$  fraction.

Mixing of petroleum from different source rocks has been identified based on the application of diamondoid biomarkers, especially for the Russian part of the Barents Sea and the Timan Pechora Basin (He et al., 2012). However, diamondoids have also been used for a sample set covering the major discoveries in the Hammerfest Basin by Murillo et al. (2016), who found maturity based on diamondoids to be in the range of 2.0 to 2.5% vitrinite reflectance for the Hammerfest Basin samples and concluded that a late dry gas charge throughout the basin occurred. Diamondoid data were also available for some selected samples in the database used for this study and have been used as a maturity tool. However, using the methods described in Dahl et al. (1999), mixing of high mature oils could not be confirmed. Yet, it may be possible that no extensive oil cracking occurred for the samples analyzed based on the stigmasterane and diamondoids concentrations. The MAI (methyl adamantane

index) and MDI (methyl diamantane index) parameters described by Chen et al. (1996) have been applied as well and a clear relation between these ratios could be observed. However, the suggested vitrinite reflectance values of Chen et al., (1996) did not fit with %Rc values based on aromatic hydrocarbons obtained in this study. Furthermore, we correlated the MAI and MDI with the 3-MP/retene ratio (cf. Schulz et al., 2001) and did not find a clear correlation between these maturity parameters. Gas analysis of samples collected from the Hammerfest Basin (unpublished data, Lerch and Karlsen) did not indicate a late dry gas charge for the Hammerfest Basin. Based on these results, mixing of high temperature generated petroleums (gas-window) with low mature petroleums could not be confirmed. These findings led to the conclusion that the application of the MAI and MDI parameters might be used with caution and that other factors might control the distribution of diamondoids in the investigated samples (cf. Schulz et al., 2001).



**Fig. 11:** Map of the study area showing the maturity trends obtained by the three different compound classes. Note that there is a decreasing maturity trend from the Tromsø Basin towards the Måsøy-Nysleppen Fault Complex, with increasing values towards the Finnmark Platform (modified after Lerch and Karlsen, 2015)

Remigration and recharge of petroleums, e.g., the general principles of Gussow (1954) and charge type, which is dependent on the cap rock properties (cf. Sales, 1997), are considered one of the most important parameters affecting petroleum distribution and composition in the SW Barents Sea. It has

been shown that a long-distance migration network in the Hammerfest Basin resulted in remigration from the greater Snøhvit area towards the southern margin of the Hammerfest Basin (Figs. 12, 13). However, it also may be possible that this migration network reaches as far as the Måsøy-Nysleppen Fault Complex, as comparable maturities and inferred depositional environments have been described for the samples from these areas.

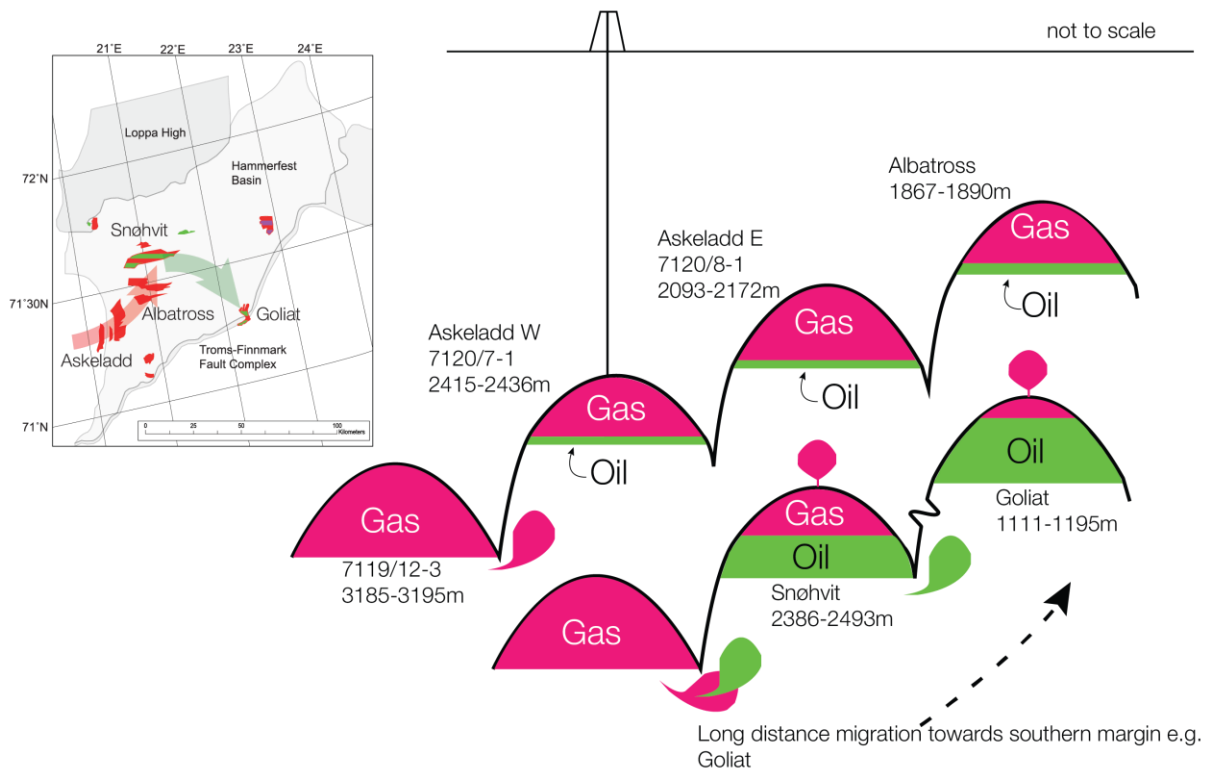
Although the study area only covers a small part of the greater Barents Sea region, additional evidences for the importance of migration/re-migration have been found. Recently, Abay et al. (2016) reported migrated oil on Svalbard, the northernmost location of the Barents Sea. Furthermore, Matapour and Karlsen (2016) discussed the reactivation of paleo-oil by more recently migrated gas and lighter hydrocarbons for the Johan Castberg discovery on the western rim of the Loppa High. Gas chimneys that have been observed on seismic profiles west of the Loppa High are evidence of live migrating gas. Recent migration of gas or LHC has also been proposed for sample B2 from the 7120/1-2 well. Based on unaltered LHC signatures in sample B2 compared to samples B and B1 from shallower reservoir compartments in the same well, ongoing, or very recent migration likely can be considered.

Paleo-migration may be treated as an important factor, to the extent that early migration has saturated the migration avenues. Later arriving condensate or gas can, in the best case, remobilize this “dead-oil”. Understanding that migrated paleo-oil, or “dead-oil”, and more recent migrated gas/condensate may result in discoveries can be crucial for modelling studies. Hence, it may be considered possible that even today, reactivation of paleo-oil columns may occur and that such processes have to be included/evaluated during basin modelling/exploration studies. Based on these results, it can be suggested that the understanding of migration routes and entrapment mechanisms are a key to interpreting migration in the past, but also during the present time.

Due to the fact that early exploration efforts mainly found gas and/or condensates, the Barents Sea was considered gas-prone only. Detailed investigations of the LHC compounds could show that phase fractionation and/or repeated gas stripping episodes occurred especially in the western part of the Hammerfest Basin and the adjacent Tromsø Basin (Figs. 12, 13). It was possible to conclude that some of the wells held liquid petroleum before and that this liquid petroleum has been displaced from the trap. Therefore, it is suggested that application of LHC compounds can be of great assistance in underexplored areas where only gas/condensates are found. If the results confirm previously present liquid petroleum, there is a high chance for making up-dip discoveries (cf. Gussow, 1954; Sales, 1997).

In order to make accurate predictions regarding generation, migration, accumulation and alteration of petroleum, it is crucial to identify the right timing of exhumation and the right amount of erosion.

Yet, as mentioned in section 2.4.1 there is consensus that three major exhumation events occurred during the last 60Ma. On the contrary, disagreement prevails on the timing and the amount of erosion. In general, it is possible to delineate regional trends compliant with Baig et al. (2016), Cavanagh et al. (2006), Doré and Jensen (1996), Green and Duddy (2010), Henriksen et al. (2011b), Laberg et al. (2012), Nyland et al. (1992) and Ohm et al. (2008): (1) zero to minor exhumation in the western part of study area i.e. Tromsø Basin and the neighboring Bjørnøya Basin; (2) moderate uplift and erosion in the range from 500m to 1500m in the Hammerfest Basin and e.g. the Troms Finnmark Fault Complex; (3) up to 2400m on the Bjarmeland Platform with decreasing values towards the Finnmark Platform (1000-1400m); (4) 1200–1950m on the Loppa High and up to 2050m in the adjacent Maud Basin, and (5) up to 3000m on the Stappen High and continuing to Svalbard. Thus, there is a clear W-E and S-N trend with increasing amounts of erosion towards the east and the north.



**Fig.12:** Sketch showing the distribution of gaseous/condensates and oil in the Hammerfest Basin. The upper section demonstrates that oil has been displaced from the traps due to uplift and gas expansion. The oil rim represents the residual oil saturation that is indicative of prior liquid accumulations. Based on biomarker signatures, it could be shown that the oils in the shallower Goliat reservoir and the Snøhvit reservoir are of common origin, indicating long distance migration from the mid part of the Hammerfest Basin towards the elevated basin margins as also shown in the map-inlet.

The present distribution of petroleum in the Hammerfest Basin can closely be related to exhumation. As shown in Figure 12 there is gas-influx into the Hammerfest Basin from the Tromsø Basin. Source rocks in the Tromsø Basin have not been affected by exhumation as the amount of erosion was only

minor. Moderate exhumation in the Hammerfest Basin however, resulted in gas exsolution and gas expansion, which forced liquid petroleum out of the trap in updip directions. Ongoing burial of source rocks in the Tromsø Basin and resulting gas influx into the Hammerfest Basin, i.e. into the Askeladd field, the present condensates are characterized by elevated aromaticity values (Paper 1) that indicate repeated gas stripping.

In addition to uplift and erosion, it has also been suggested that hydrocarbon spillage can be linked to glacial loading/unloading (Cavanagh et al., 2006; Doré and Jensen, 1996; Duran et al., 2013; Kjemperud and Fjeldskaar, 1992; Lerche et al., 1997). In contrast to Green and Duddy (2010), who considered the influence of glaciations as negligible, Kjemperud and Fjeldskaar (1992) pointed towards the importance of reservoir tilting induced by differential glacial loading/unloading. Tilting of reservoirs in turn results in shift of the spill point, this can lead to changes in remigration routes, but also to reduced or increased trap capacity. New migration routes could be established, while older migration avenues, active prior to glaciations, would become inactive. Thus, during several stages of glacial loading/unloading the spill point might have shifted numerous times. Hence, it might be possible that petroleum with equal geochemical characteristics are found on both sides of the spilling trap. Here, the occurrence of possible petroleum blends would result in varying maturity, alteration and facies signatures as shown in Lerch et al. (2016a,b,c).

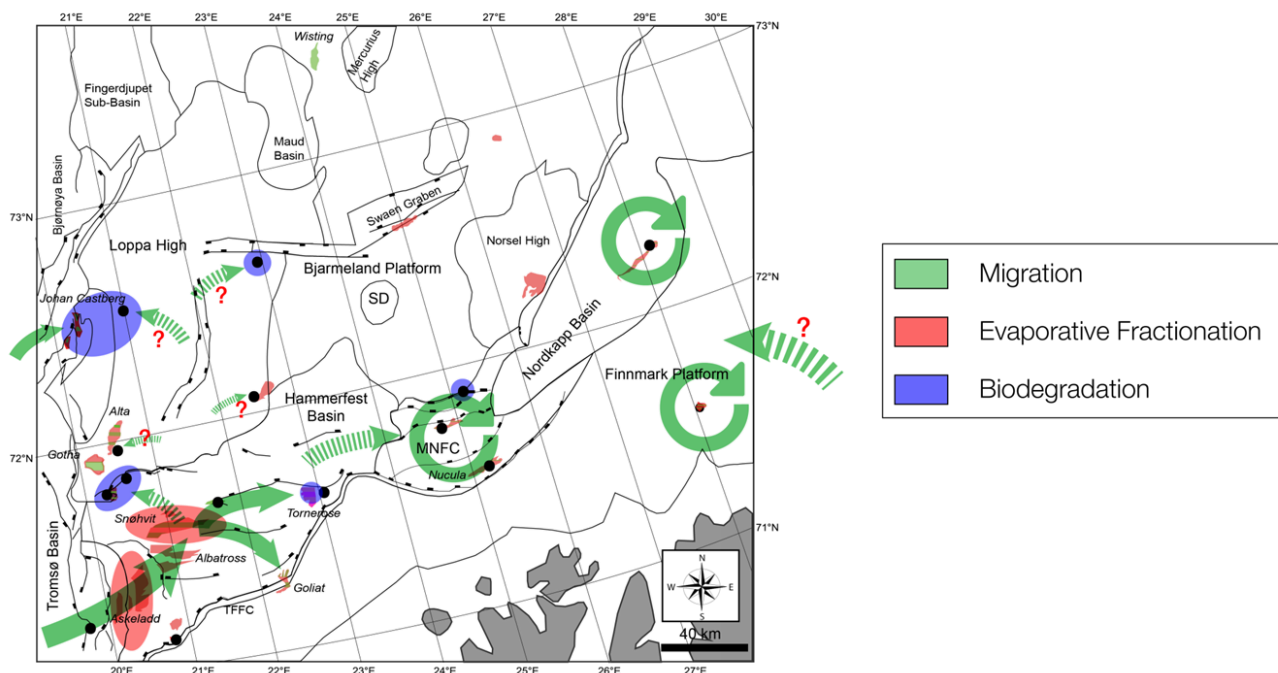
Furthermore, temperature and pressure fluctuations caused by glacial/interglacial events can affect the hydrocarbon densities and thus will lead to volume changes in the trap (cf. Fig. 9), as the traps are buried to greater and uplifted to shallower depth during glacial loading and glacial unloading, respectively. Density changes in combination with gas exsolution in turn will also favor the remigration of liquid hydrocarbons.

Cycles of ice-sheet loading/unloading not only affected the trap geometry, spill-point modification and density variations, but also could have favored microbial alteration in traps. For a long time aerobic microbial activity has been considered the main hydrocarbon degrading factor (Palmer, 1993), until more recently (Head et al., 2003; Jones et al., 2008) pointed towards the importance of anaerobic, methanogenic degradation. Biodegradation in onshore reservoirs often has been linked to meteoric water intrusion that is able to import oxygen, nutrients and microbial communities, while the same process has been questioned for cold shallow offshore reservoirs (Wenger et al., 2002). Generally, continuous subsidence of a basin results in an updip water flow towards the basin margins. However, if the basin is uplifted, the hydraulic system is reversed, leading to a water flow that is directed towards the basin center (Doré et al., 2002). Lower or non-existing sea-levels during glacial stages led to a more elevated groundwater table onshore. Bjørlykke (2015) showed that meteoric water is able to intrude into sedimentary basins as much as 40 times the height of the groundwater table due to an increase in the hydrodynamic head. The influence of ice sheets on groundwater flow has been reported

by Boulton et al. (1995) and Forsberg (1996). Furthermore, it has been concluded that cyclic pulses of pressure (glacial-loading) and retreat (glacial-unloading) can result in a pumping effect that may cause significant changes in subsurface flow regimes as deep as 2-3km below the surface (Boulton et al., 1995; Cavanagh et al., 2006; Forsberg, 1996; Kjemperud and Fjeldskaar, 1992; Lerche et al., 1997). Considering the depths of the reservoirs from which the biodegraded samples have been collected, it seems likely that oxygenated meteoric water intrusion can be regarded as a possible alteration process. Even though Head et al. (2003) mentioned that oxygen transport over long distances is not likely due to its high reactivity and that even in relatively shallow reservoirs (<500m depth) anaerobic degradation is preferred.

It has been shown that several controversies exist regarding the exhumation events and their impact on petroleum systems. The aim of this study was to demonstrate what kind of alteration processes occurred in the Barents Sea, but it also made clear that more research needs to be done in order to fully understand the interplay of exhumation, erosion, glaciations and petroleum systems.

The processes discussed are considered to have a strong influence on petroleum systems. Wrong estimates of exhumation or erosion thus could lead to erroneous results regarding the thermal maturity of source rocks, volumetric calculations, PVT considerations and migration routes. Due to the fact that the amount of uplift changes quite dramatically over the whole shelf, each petroleum system in a specific area has to be evaluated independently. It was possible to show that microbial alteration occurred in areas that experienced greater exhumation e.g. the Troms Finnmark Fault Complex, the Loppa High and the Måsøy Nysleppen Fault Complex towards the east. Thus, it could be interesting to investigate if petroleum systems that are found further north, in areas that are characterized by greater amounts of exhumation, exhibit biodegradation signatures as well.



**Fig. 13:** Map of the study area showing the different alteration signatures related to basin location. Evaporative fractionation is mainly recorded in the eastern Tromsø Basin and the western part of the Hammerfest Basin, while biodegraded samples mainly have been found on structural highs or elevated basin margins. The green arrows indicate migration directions, while the circled arrows suggest a more local migration or unknown migration direction. It is unclear if the petroleum from the Loppa High have been charged locally e.g. mature source rocks on the Loppa High, or if the petroleum migrated on the Loppa High (modified after Lerch and Karlsen, 2015)

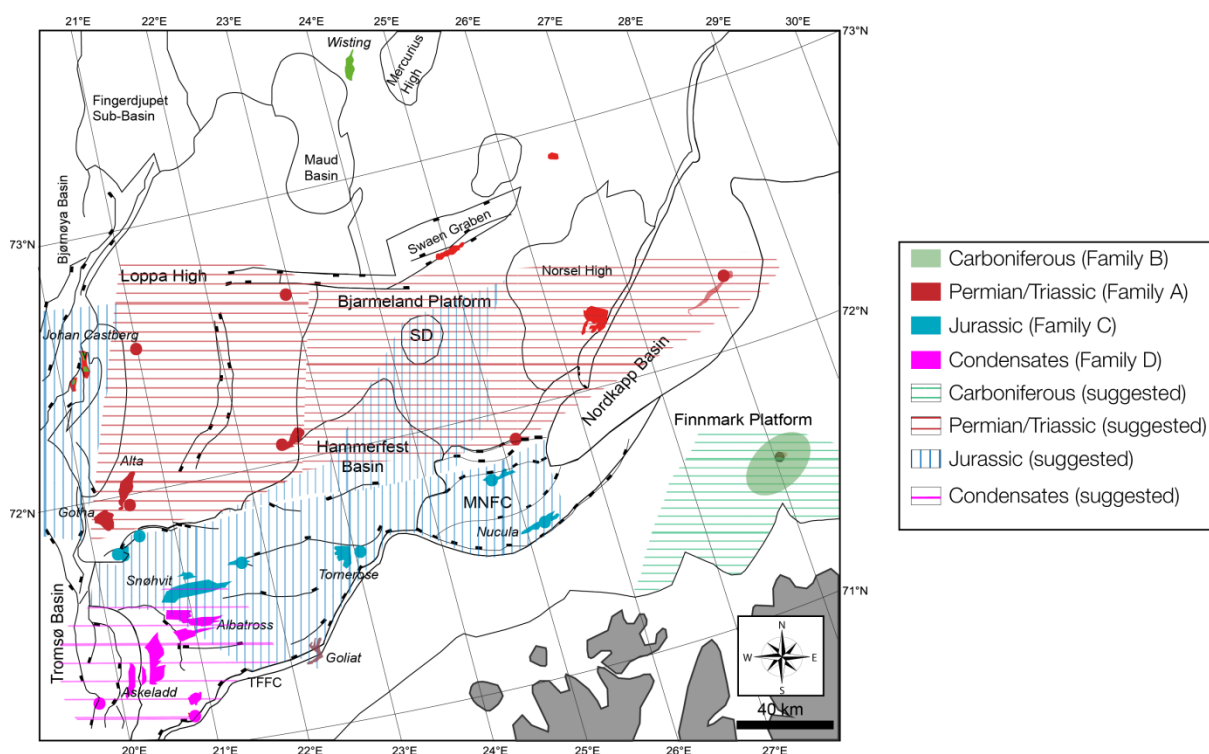
The findings furthermore demonstrate that the petroleum families and their source rock/age affinities are largely predictable from position and type of the structural compartments where the petroleum have been found (Fig. 14). Organic facies parameters indicated a dominant contribution from Type II, Type II/III and Type III kerogen. However, Type I kerogen may have contributed to some Triassic source rocks (cf. Vigran et al., 2008). The depositional environments range from marine, shallow marine, coastal plain, delta plain, lacustrine to terrestrial dominated settings with redox conditions varying from anoxic to oxic. It has been possible to classify four petroleum families based on molecular characteristics and multivariate statistical methods.

Family A petroleum, generated from inferred Permian/Triassic source rocks, are mainly found on the Loppa High, the southern margin of the Hammerfest Basin i.e. the deeper Goliat oils, and the Nordkapp Basin, while Jurassic derived petroleum of Family C are mainly found in the central part of the Hammerfest Basin and its surrounding basin margins. Yet, Jurassic source rocks may also play an important role in the eastern Hammerfest Basin and a partial role on the Måsøy-Nysleppen Fault

Complex. Carboniferous generated petroleum (Family B) probably comprise important charges on the Finnmark Platform and it may be speculated that more findings could be made in Upper Permian carbonates. Hydrocarbon generation from late oil mature Triassic and Jurassic source rocks in the Tromsø Basin and the western part of the Hammerfest Basin resulted in a series of condensate discoveries in the western and central part of the Hammerfest Basin (Family D) (Fig. 14).

The suggested age classification in this study is corresponding well with results and suggestion from earlier studies by Ohm et al. (2008) and Rodrigues Duran et al. (2013). However, results by Killops et al. (2014) slightly contradict observations made in this thesis. Killops and co-authors suggested a Permian origin for an oil from the 7128/4-1 well on the Finnmark Platform, while results in this study indicate that oils from this well are likely to be petroleum blends, with a dominant contribution from Carboniferous source rocks.

In general, an advantage for effective oil-source rock correlations would be the availability of source rock samples that have been drilled from basin centers and not only from structural highs. Analyzing source rocks that actually display the current thermal maturity would enhance the chance to determine geochemical characteristics that allow an efficient correlation between the generated product and the source.



**Fig. 14 (previous page):** Map of the study area showing the distribution of petroleum systems related to the age of the source rocks. The wells and fields (accumulations) are colored in the respective color of the age of the petroleum systems, while the dashed lines represent an interpolation of the dominant petroleum age (modified after Lerch and Karlsen, 2016b).

It has been reported in Lerch et al. (2016c) that the Permian/Triassic sourced Family A shows some contradicting organic facies signatures, ranging from Type II to Type II/III and also possible Type I kerogen, while the paleo-depositional environments have been suggested to range from marine, shallow marine, coastal plain, delta plain, lacustrine to terrestrial dominated settings with redox conditions varying from anoxic to oxic. The most dominant distinctions between the petroleum families in Lerch et al. (2016c) have been evaluated based on the abundances of tri- and tetracyclic terpanes. Lerch et al. (2016c) suggested a characteristic “terpane-triplet” (sparse  $C_{24}$ TET and more abundant  $C_{26}$ TT) to be indicative of Permian/Triassic sourced petroleum systems. Furthermore, the ETR (Holba et al., 2001) has successfully been applied to differentiate between Permian/Triassic (Family A) and Jurassic (Family C) sourced oils. The origin of tricyclic terpanes has been controversially discussed over the last years. While Ourisson et al. (1982) considered tricyclic terpanes to be diagenetic products of prokaryotic membranes, Revill et al. (1994) and Simoneit et al. (1993) considered the origin of tricyclic terpanes in *Tasmanites*. However, Farrimond et al. (1999) mentioned that tricyclic terpanes have been observed in various sediments and Dutta et al. (2006) and Samuel et al. (2010) advised that a relationship between tricyclic terpanes and *Tasmanites* does not always exist and that their occurrence may also be related to other biological sources. Greater abundances of  $C_{24}$ TET have been considered to indicate carbonate/evaporitic and terrestrial depositional settings (Palacas et al., 1984; Philp & Gilbert, 1986). However, the abundance of  $C_{24}$ TET is generally low in Family A samples compared to the tricyclic terpanes and also to the Families B, C and D. Most parameters that apply the  $C_{24}$ TET indicate lacustrine to marine origin of the samples (Fig. 8 in Lerch et al. 2016c), indicating variations in organic matter input, which is also demonstrated by greater abundances of  $C_{27}$  and  $C_{29}$  steranes, but also variations in redox conditions during deposition i.e. Pr/Ph and homohopane distribution (Figs. 12 and 14 in Lerch et al., 2016c).

In order to assess which depositional settings may have resulted in the biomarker distribution observed for Family A, correlation with several palaeogeographic maps that demonstrate source rock depositional environments during the Triassic has been applied (Høy and Lundschieen, 2011; Kaminsky et al., 2011; Krajewski, 2013; Riis et al., 2008; Xu et al., 2009). While Kaminsky et al., (2011) concluded central shelf, shoaly marine, nearshore continental and continental lacustrine-alluvial depositional settings in the study area (Fig. 22.7, Kaminsky et al., 2011), Høy and Lundschieen (2011) suggested a prograding delta system that developed from the SE towards the NW (see also Fig. 15). Høy and Lundschieen (2011) agree with Xu et al. (2009) who mention that the deposition of the Triassic Botneheia Formation and its offshore equivalent, the Steinkobbe Formation, occurred at the

same time, and thus can be considered a regional phenomenon, even if the depositional centers are up to 600km apart from each other. However, disagreement between Høy and Lundschieen (2011) and Xu et al. (2009) prevails regarding the redox conditions during deposition. While Xu et al., (2009) argue that the redox conditions were different from location to location, ranging from more reducing conditions around the Svalis Dome, where bottom water anoxia can be correlated to reduced water circulation caused by embayments, Høy and Lundschieen (2011) discuss that prograding deltas from the Russian part and fresh water influx from Siberian rivers not only carried terrestrial detritus, but also induced dysoxic/anoxic conditions due to development of haloclines. The occurrence of *Tasmanites* that are considered an important contributor to marine organic matter for Triassic source rocks has been concluded by Høy and Lundschieen (2011) as well. The model described by Høy and Lundschieen (2011) thus suggests a more marine, anoxic depositional setting in the Svalbard region towards the NW, and a more deltaic, lacustrine influenced facies in the SE.

However, a more detailed depositional model of the Botneheia Formation was prepared by Krajewski (2013), who argued that the deposition of the Botneheia Formation demonstrates a transgressive-regressive interplay between the prodelta system on the south eastern Barents Shelf (cf. Høy and Lundschieen, 2011), and an open marine system that has been influenced by marine upwelling from the Panthalassic Ocean north of Svalbard. Family A samples (Lerch et al., 2016c), sample 526a (He et al., 2012) and samples analyzed by Abay et al. (2016) are characterized by elevated amounts of C<sub>28</sub> and C<sub>29</sub> cheilanthanes that result in high ETR's and are indicative of Triassic age. However, it was Holba et al. (2003) who report that the ETR can be influenced by marine upwelling. Since the samples from Svalbard (Abay et al., 2016; He et al., 2012) show distinct greater ETR 's than Family A samples from the Barents Sea, it can be suggested that the Svalbard samples are influenced by marine upwelling as shown in Figure 26 in Krajewski (2013). The reason behind the lower ETR values for Family A samples might thus be related to deposition of the inferred source rock in non-upwelling areas, or the signal might be diluted by Permian contribution.

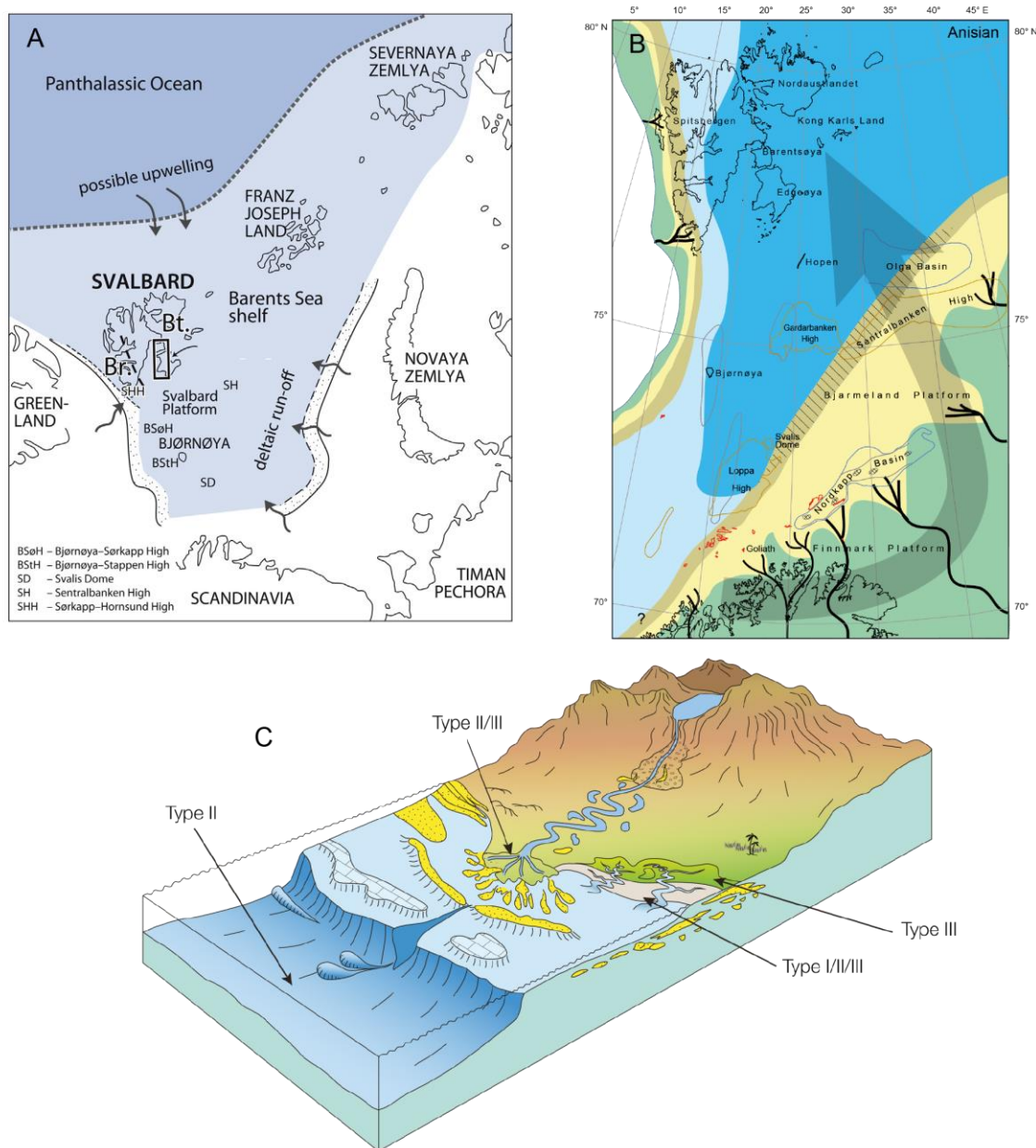
Krajewski (2013) also demonstrated that parts of the Botneheia Formation (Muen Member) are characterized by land plant derived debris and autochthonous organic matter that is indicative of prodelta depositional environments, as described for the Barents Sea (cf. Høy and Lundschieen, 2011). Furthermore, it has been shown that variable inputs of organic matter derived from different sources characterize the depositional environments in stratified basins as a result of water column stratification (salinity and/or temperature) (Høy and Lundschieen, 2011; Krajewski, 2013). Thus, it seems plausible that even petroleum generated from the same source interval may show different organic facies signatures related to differential input.

Biomarker analysis revealed prevalent petroleum generation from marine Type II to mixed Type II/III to Type III/II kerogens, with possible contribution from kerogen Type I to Family A samples. The

regressive-transgressive model concludes the deposition of Kerogen Types ranging from Type I to Type III and includes the observation that *Tasmanites* contribute to marine derived organic matter (Krajewski, 2013). The occurrence of *Tasmanites* that could have resulted in greater abundances of tricyclic terpanes as observed in Family A is in agreement with Revill et al. (1994) and Simoneit et al. (1993), who both suggested *Tasmanites* being the biological origin. Observations that Family A has been sourced from source rocks that have been deposited in lacustrine environments could not be confirmed due to the absence of lacustrine specific biomarkers. However, based on the paleo depositional model by Høy and Lundschieen (2011), it seems likely that some samples have been sourced from intervals deposited as prodelta facies that may result in a lacustrine facies offshore.

Correlating the biomarker fingerprints of Family A (Lerch et al., 2016c) with the proposed palaeogeographic maps and depositional settings, it emerges that the models suggested by Høy and Lundschieen (2011) and Krajewski (2013) can both partially be attributed to depositional settings of the inferred source rocks. Thus, a combined model of Figure 1b (Krajewski, 2013) and the depositional setting described by Høy and Lundschieen (2011) would best explain the biomarker signatures of the Triassic sourced fractions of Family A (Lerch et al., 2016c). Yet, possible mixing signatures and co-sourcing from Permian source rocks in some cases are not considered in these models. Moreover, every co-charge from a Permian source rock may affect the interpretation. This has been shown e.g. for sample C (7120/2-1), which is suggested to have a Permian contribution. Furthermore, the complex depositional systems during the Triassic i.e. closed/open embayments, restricted water circulations, oxic to dysoxic to anoxic conditions, input of varying organic matter, vertical and lateral facies changes and the development of possible niche environments (Høy and Lundschieen, 2011; Kaminsky et al., 2011; Krajewski, 2013; Riis et al., 2008; Xu et al., 2009) make it difficult to attribute certain environmental conditions to certain samples.

As mentioned in Paper 3 (Lerch et al., 2016c) it can be claimed that the samples in the database do not represent the “whole Barents shelf” and that samples from Family A may more accurately represent the delta to lacustrine facies deposited in the SW part. Sample 526a (He et al., 2012) and samples analyzed by Abay et al. (2016), however, could represent charges from the source rock intervals that have been influenced by marine upwelling. Thus, it would be of great advantage to cover the area between our northernmost point in the study area and Svalbard to determine if there is a regional trend in ETR's and tri- and tetracyclic terpane distribution.



**Fig. 15:** (a) Paleo- reconstruction map indicating the depositional environments of Svalbard and the Barents Shelf modified after Krajewski (2013). Note that the possible marine upwelling could have resulted in higher ETR ratios of samples collected from Svalbard. The deltaic run-off environment is shown in Figure 14b, (b) Paleo-depositional map of the Anisian modified after Riis et al. (2008). The black arrow indicates the progradational character of the sediments during the Anisian, (c) simplified source rock depositional model showing the different kerogen types that may have been developed due to varying organic matter input. The contemporary deposition of marine, mixed marine/terrestrial, and terrestrial organic matter during the Triassic makes it difficult to define a Triassic source facies (modified after NPD, 2016).

It could be shown that systematic evaluation of different hydrocarbon classes is powerful for regional correlation studies when considering thermal maturity, alteration and source depositional facies of the petroleum. It may still be possible that the interpretation of the organic matter input and depositional environments is biased by the selection of the samples in the current database. While it could be achieved to differentiate between Jurassic and pre-Jurassic generated petroleum, a more complicated scenario emerged trying to discriminate Permian and Triassic sourced samples. One of the main challenges not being able to define a Permian and/or a Triassic signature may be related to the blended character of the petroleum and the fact that the more dominant petroleum phase possibly “blends out” the less dominant phase. Newly available samples may for example shed light on a distinct Permian or Triassic facies signature, which may have been “blended-out” in the present dataset. A first step towards this goal has been undertaken by Pedersen (2016, personal communication) who reported oil from the very recent Gotha discovery to be sourced from Upper Permian source rocks. It has been considered likely that the depositional settings during the Permian grade from restricted carbonate, hyper saline, and even sabkha, to a more open marine organic facies. Deposition in the Triassic, however, varies from a more terrestrial, deltaic influenced setting towards an open marine environment. Based on these observations, it is considered quite difficult to define a “unique” Permian or Triassic biomarker signature. Yet, it is reasoned that with the availability of more Permian and Triassic source rock samples, a successful oil – source rock correlation can be established.

However, it is believed that the current thesis can be used as a basis for future studies working with petroleum systems in the Barents Sea, because the regional correlation approach has made it possible to map-out variations in maturity, alteration and organic matter input into paleo-depositional environments. Furthermore, this study may have implications for circum Arctic basins.

During the last three years of this study, it has always been tried to understand and interpret the data in a petroleum system context and not only as geochemical information used in oil-oil correlation studies. Because all the essential petroleum system elements and processes that have been described previously above can influence a petroleum system, they have to be considered as well. It is believed that the systematic processing and integration of geochemical information into a geological frame is a powerful tool in regional petroleum system studies. Despite the fact that interpretation of petroleum samples in a multi-source rock basin can be challenging, the benefits of investigating the chromatograms “section-by-section” to establish a genetic fingerprint of the samples have been proven. The innovative nature of this study – analyzing hydrocarbon fraction by hydrocarbon fraction – and support molecular geochemical results by multivariate statistical treatment has shown that such an approach is needed for recognizing altered and/or blended petroleum, instead of relying on a single compound fraction only. This procedure allowed, in combination with a regional geological observation, to effectively map out the existing petroleum systems and their characteristics.

## 4.1 The Oil Families in a Regional Context

A geochemical study with assistance of chemometric analysis conducted on 34 oil samples from the Russian part of the Barents Sea, the Timan Pechora Basin and Svalbard revealed the presence of six oil families (He et al., 2012). In order to paint a bigger regional picture, the oil families defined by He et al. (2012) are correlated with the oil families characterized in this study. Due to the fact that the oil families II and III (He et al., 2012) have been generated from various organo facies of the Devonian Domanik Formation, and there are no known Devonian source rocks in the SW Barents Sea, these two families are excluded from the correlation as well as the Carboniferous sourced Family B from the Finnmark Platform (Lerch et al., 2016c) because He et al. (2012) do not report on Carboniferous sourced petroleum from the Russian side. It is also impossible to correlate family D (Lerch et al., 2016c) that comprises condensates only, as He et al. (2012) refer to all samples as oils, regardless of the physical properties.

He et al. (2012) described oil family I as being Triassic sourced. The following attributes have been described:  $\delta^{13}\text{C SAT}$  (-26.25‰ to -29.83‰) and  $\delta^{13}\text{C ARO}$  (-27.55‰ to -29.66‰), high ETR (>2), but varying  $\text{C}_{29}/\text{C}_{30}$  hopane values that indicate varying organic matter input. Oil family IV, that is co-sourced from Triassic and Devonian Carbonate source rocks, is characterized by  $\delta^{13}\text{C SAT}$  values between -28.81‰ and -30.48‰ and  $\delta^{13}\text{C ARO}$  values between -28.64‰ and -30.22‰, and by low  $\text{C}_{27}/\text{C}_{29}$  and  $\text{C}_{28}/\text{C}_{29}$  sterane values that indicate terrigenous source input. Both oil families have ETR values >2 that suggest a Triassic source, while the lower values for family IV could be related to the Devonian co-sourcing. Oil family IV ETR values are in the same range as values for oil family A in this study (Lerch et al., 2016c). This could support the hypothesis that oil family A represents a co-sourced Permian/Triassic family where the Permian contribution results in lower ETR values (see oil family IV of He et al., 2012) compared to the high ETR values of the pure Triassic oil family I of He et al. (2012). What both oil families I and IV (He et al. 2012) and oil family A (Lerch et al., 2016c) have in common are higher  $\text{C}_{27}$  and  $\text{C}_{29}$  over  $\text{C}_{28}$  sterane values that suggest deposition in transitional environments that has been described as common during the Triassic period (cf. Riis et al., 2008; Krajewski, 2013).

However, sample 526a (He et al., 2012) represents a Triassic sourced oil from Spitsbergen and has a  $\text{C}_{29}\alpha\beta/\text{C}_{30}\alpha\beta$  ratio of 0.54, an ETR of 4.12 and thus shows much higher values for Triassic sourced oil than values found in this study (see Figs. 5, 13a, Lerch et al., 2016c). Yet, migrated oil stains on Svalbard have ETR values between 3.18 and 4.61, and are reported to have been sourced from the Lower Triassic Botneheia Formation (Abay et al., 2016). Thus, it might be possible that the higher ETR values for the northernmost samples are to some degree influenced by marine upwelling (Holba et al., 2001) that has been suggested in a palaeoenvironmental model by Krajewski (2013) for the

Svalbard archipelago. Stable isotope values  $\delta^{13}\text{C}$  SAT of -29.83‰ and  $\delta^{13}\text{C}$  ARO of -29.66‰, and 47% of  $\text{C}_{29}$  sterane correspond closer to values that characterize family A (Permian/Triassic) in this study than the remaining samples of oil family I (He et al., 2012).

He et al. (2012) concluded, based on biomarker characteristics of oil family I, that a deep marine shale facies is the main oil generator for Triassic derived oils in the eastern Barents Sea (Russia) and on Svalbard. The only possible candidate for the Triassic sourced samples on Svalbard is the Lower Triassic Botneheia Formation that developed in an open shelf environment characterized as an embayment bordered by deltaic settings and characterized by fluctuating redox conditions due to restricted water circulation (Mørk et al., 1982; Mørk et al., 1989; Mørk et al., 1993). Based on these facts, it does not seem likely that the Triassic sample 526a has been generated from the same source rock as the other samples from oil family I (He et al., 2012). However, biomarker signatures and the good correlations to findings by Abay et al. (2016) make it seem likely that this sample has been sourced from the Botneheia Formation. Based on the higher ETR values of sample 526a (He et al., 2012) and the migrated oil stains (Abay et al., 2016) it also seems likely that the Svalbard samples represent a more marine influenced facies, deposited under upwelling conditions, while Family A samples represent the complex and complicated signatures of source rocks deposited under transitional conditions with varying organic matter input.

Concluding, it could be demonstrated that the suggested Triassic sourced oil families I and IV (He et al., 2012) show similarities, but also variations among the geochemical compounds. Even though organic rich intervals have been deposited throughout the Arctic, i.e. North Alaska and the Canadian Sverdrup Basin and Russia (He et al., 2012; Leith et al., 1993), the author suggests that a direct correlation of oils from the different areas may not be successful as the paleo-environmental and paleo-depositional conditions among the different basins were quite variable. Thus, an oil-oil correlation among samples from the eastern part (Russian Barents Sea, Timan Pechora Basin) and samples from the study area may not be successful. Furthermore, the complex and varying biomarker signatures, in combination with possible mixing, do not allow defining a “Triassic fingerprint” for the samples analyzed.

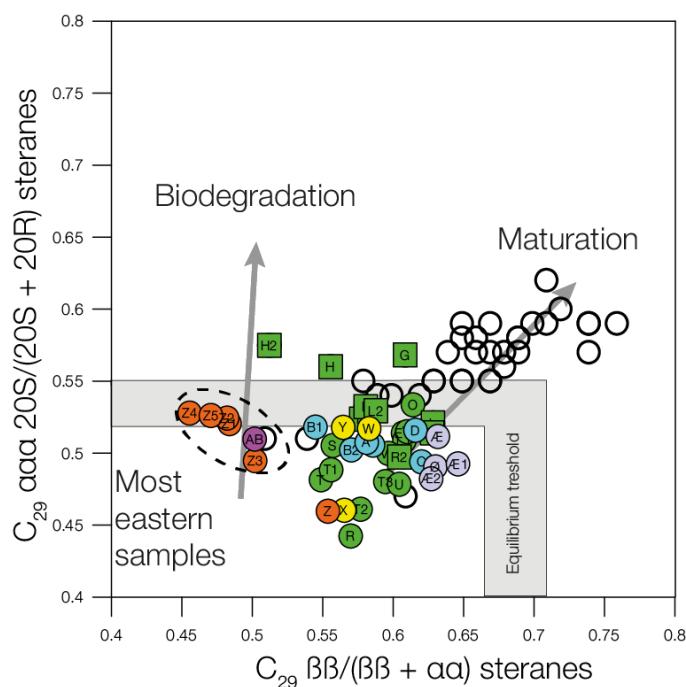
Oil families V and VI of He et al. (2012) have been defined as being generated from Upper Jurassic and Lower-Middle Jurassic source rocks, respectively. Family V oils show high Pr/Ph values,  $\delta^{13}\text{C}$  SAT values between -27.67‰ to -29.3‰ and  $\delta^{13}\text{C}$  ARO values from -26.13‰ to -28.27‰. Family V is characterized by higher  $\text{C}_{29}$  sterane abundances that indicates more terrigenous input and is in accordance with a dysoxic/oxic depositional environment based on higher Pr/Ph values. ETR values <2 indicate a Jurassic origin as well. Family VI samples show Pr/Ph values >3 indicative of oxic conditions during conditions. Stable isotope values for the SAT fraction range between -28.8‰ and -30.7‰ and for the ARO fraction from -26.79‰ to -29.14‰. Elevated % $\text{C}_{29}$  steranes and high tricyclic

terpane ratios suggest a paralic deltaic shale (He et al., 2012). However, oils classified as Family C in Lerch et al. (2016c) show distinct geochemical signatures.

Sample 561 (He et al., 2012) is derived from Spitsbergen Island and classified as being generated from Lower-Middle Jurassic source rocks. To the knowledge of the author, there are no reports on Lower to Middle Jurassic source rocks on Svalbard. A possible source rock candidate for sample 561 (He et al., 2012) thus might be the Upper Jurassic Agardhfjellet Formation, which corresponds to the Upper Jurassic Hekkingen Formation offshore in the Barents Sea. He et al. (2012) mentioned a higher terrestrial input for Family VI that has also been observed for some samples of Family C (Lerch et al., 2016c). It has been suggested that the terrestrial signature represent a more near shore deposited part of the Upper Jurassic Hekkingen Formation. Hence, the terrestrial signature of sample 561 (He et al., 2012) might reflect charging from a more proximal deposited part of the Upper Jurassic Agardhfjellet Formation that also shows abundant Type III kerogen and variations in stable carbon isotope values that indicate terrigenous origin (Abay et al., 2016; Koevoets et al., 2016). However, the Lower Jurassic Nordmela Formation is potential source rock in the western part of the Barents Sea. These source rock intervals are characterized by mixed terrestrial and marine organic matter input, with coaly intervals that increases the capability to generate more waxy oil (Ohm et al., 2008; Stewart et al., 1995). Overall, oil family VI (He et al., 2012) seems to be generated from a source rock deposited under more oxic conditions than the samples from Family C (Lerch et al., 2016c). Based on these observations it seems likely that the Russian samples have been charged from a different Jurassic source rock interval than the samples from the Norwegian part of the Barents Sea.

In general, it is to mention that correlation between the oil families of He et al. (2012) and the oil families of Lerch et al. (2016c) can be complicated, as only two samples derive from Norwegian waters. Furthermore, the depositional settings in the Russian part and the Timan Pechora Basin were quite different compared to the Norwegian Barents Sea and for now also the tectonostratigraphic models that link the western and the eastern part of Barents Sea are poorly understood (Smelror et al., 2009).

A more recent study on oils and condensates from the Hammerfest Basin has been tailored by Murillo et al. (2016). PCA and HCA have been applied as well and their results support the findings contained in this study. Family I and II of Murillo et al. (2016) correspond to Family D in Lerch et al. (2016c), while Family III of Murillo et al. (2016) is in agreement with sub family C-II of Family C. Murillo et al. (2016) regarded their Family IV to the deeper Goliat oils, which have been characterized as part of Family A in Lerch et al. (2016c). These observations are in agreement with results obtained by Lerch et al. (2016a, b, c) that petroleum in the Hammerfest Basin have been generated from Type II to Type III kerogen source rocks with varying thermal maturities.



**Fig. 16:** Cross-plot of  $\beta\beta/(\beta\beta+\alpha\alpha)$  and  $20S/(20S+20R)$   $C_{29}$  steranes. The black circles indicate samples taken from He et al. (2012). See text for discussion.

It has been shown in Paper 2 (Lerch et al., 2016b) that the isomerisation values for the  $\beta\beta/(\beta\beta+\alpha\alpha)$  and the  $20S/(20S+20R)$   $C_{29}$  steranes plot with lower than equilibrium values. In order to understand if the distribution of our samples, in terms of isomerisation, might represent a regional trend, samples from this study were compared with data published by He et al. (2012) (Fig. 16, black open circles). Surprisingly, most of the samples analysed by He et al. (2012) plot well beyond the isomerisation equilibrium threshold, leading to a clear separation between the samples from the western part (Norway, study area of Lerch et al. 2016a, b, c) and the eastern part of the Barents Sea (Russia), including the Timan Pechora offshore/onshore region.

Maturity assessment by He et al. (2012) inferred petroleum generation from the early part to the late part of the oil window, which is comparable to the maturity interval found in this study (Lerch et al., 2016b). One may only speculate about this mismatch, but it is suggested here that the “higher than equilibrium” isomerisation values of He et al. (2012) might reflect that the majority of their Barents Sea offshore oils could represent long distance migrated oil from the deeper part of the eastern Barents basin, which migrated up-dip from the “foreland basin” west of Novaya Zemlya. Van Koeverden et al. (2010) presented geochemical data of migrated bitumens from onshore Novaya Zemlya, which showed  $20S/(20S + 20R)$  and  $\beta\beta/(\beta\beta + \alpha\alpha)$  values of 0.43 to 0.57 and 0.42 to 0.59, respectively, correlating closer to our values, and it was speculated if the associated generation event could have involved Cretaceous or Tertiary source rocks, as the main basin to the west is buried ca. 14km depth.

These evidence imply that the deep foreland basin west of Novaya Zemlya has been, and is in fact today expelling petroleum towards the west and onto e.g. the Fedinsky High and towards the former

“Grey Zone”. Thus, the deep buried source rocks are not only resulting in gas/condensates in e.g. the Shtokman Field and associated structures.

#### 4.2 Suggestions for Future Work

The results obtained in this study open the possibility for further geochemical research in the Barents Sea. The author would like to address the following suggestions for future research:

##### *Gas analysis*

In order to complete the fingerprints of the samples used in this study, additional data on gases would be of great interest. Geochemical analysis of gases is able to differentiate between biogenic gas, produced by bacteria under anaerobic conditions, and thermogenic gas that is formed under high temperatures. Thermogenic gas can either be produced by the source rock itself, the so called primary thermogenic gas, or by thermal cracking of oil, the so called secondary thermogenic gas. Isotope analysis and composition of thermogenic generated gas can be used to reveal the source rock maturity and mixing of petroleum phases as applied for the Hammerfest Basin in Rodrigues Duran et al., (2013). Furthermore it is possible to differentiate between oil-associated gas and dry, post-mature thermogenic gas. This additional information would increase the accuracy for mixing when comparing the maturation data with available maturation indices for source rocks e.g. on the Loppa High and the eastern part of the study area.

##### *Paleo-migration Events*

The presence of multiple source rocks suggests several generation and migration pulses from the organic rich strata. However, despite having potential Paleozoic source rocks, only a few petroleum systems have been suggested being derived from Carboniferous or Permian sources. To deepen the understanding of paleo-migration events, analyses of so-called dry wells and application of fluid inclusion studies is valuable. Fluid inclusions are small petroleum accumulations that are enclosed in minerals and have been successfully employed for reservoir charge histories (Karlsen et al., 1993). The migration and reservoir charge history of the Permian carbonate play on the Loppa High is of personal interest to the author. Analysis of fluid inclusions from wells adjacent to and on the Loppa High could be used for thermal maturation studies during charging, to identify possible displaced petroleum systems due to uplift, tilting and leakage and to realize migration avenues. The research question that should be addressed here is: Are the hydrocarbons on the Loppa High autochthonous, or have they migrated or example from the adjacent Bjørnøya Basin? Therefore, correlation with source rocks is inevitable (see next point).

### *Paleozoic Petroleum and Source Rocks*

Due to the lack of age-specific biomarkers it was quite challenging to classify the samples regarding their geologic age. Supporting data could be gathered if available Paleozoic source rock samples would be analyzed. Due to the deep burial depths of Paleozoic strata in the western part of the study area, correlation with postmature source rocks is not considered likely due to the absence of biomarkers. However, it is suggested that Paleozoic petroleum systems play an important role on the Finnmark Platform and the Nordkapp Basin, where Jurassic and Triassic source rocks have partly been affected by uplift and erosion. Thus, more detailed oil-source rock correlation studies in the eastern part of the study area, with possible correlation to Russian oils and source rocks may enhance the understanding about the Paleozoic petroleum systems. Yet, if the discoveries on the Loppa High have been charged from local sources, characterization of Permian and Triassic source rocks from the Loppa High would enhance the correlation potential.

### *Cretaceous Source Rocks*

Even though the application of NDR and NCR parameters did not find evidence of a Cretaceous source rock contribution to the C<sub>15+</sub> hydrocarbon fractions in the current database, there may be the possibility of Cretaceous expelled petroleum especially in the western part of the study area, west of the Loppa High and towards the North in the area of the Fingerdjupet Sub Basin. It is possible, as mentioned earlier, that the database may be biased based on the well locations. However, investigation of Cretaceous source rocks may help to better understand their generation potential and detecting possible geochemical markers that are characteristic for the Cretaceous may help to decipher a Cretaceous contribution.

### *Recent Oil Samples*

Several new wells have been drilled since initiation of this study in spring 2013. Analysis of new petroleum samples would enhance the significance of the present database. Of special interest are samples from the Loppa High (Gotha, Alta) that would improve the understanding of the Paleozoic/Triassic petroleum systems. Furthermore, petroleum from the Hoop Area, northeast from the Loppa High, could be used for correlation. Here, the Wisting and Hanssen discoveries could shed new light on petroleum systems in areas that are located further north.

### *Shallow Cores*

Intensive shallow core sampling (IKU, Sintef) at Dora in 2013 resulted in significant amounts of source rock samples and sandstone samples with oil or bitumen stains. The shallow cores have mainly been drilled in the eastern part of the study area in the Nordkapp Basin and on the Finnmark Platform. Analysis of these samples would allow source rock characterization and/or information on migrated hydrocarbons, and thus about the petroleum systems in the area. However, since the maturity of most

of the shallow cores is too low, correlation with expelled and generated hydrocarbons might be challenging or impossible.

## 5 References

- Abdullah, W.H., Murchinson, D., Jones, J.M., Telnæs, N. and Gjelberg, J., 1988. Lower Carboniferous coal depositional environments on Spitsbergen, Svalbard. *Organic Geochemistry*, 13, 953–964
- Abay, T.B., Karlsen, D.A., Pedersen, J.H., Lerch, B., Schwark, L. and Backer-Owe, K., 2014. Regional variation in the Triassic organo-facies signatures of the Barents Sea: Is there a recognizable Triassic geochemical signature for the Kobbe/Steinkobbe/Botneheia Fm.? Poster Presentation, Arctic Conference Days 2014, June 2-6, Tromsø, Norway.
- Abay, T.B., Karlsen, D.A., Lerch, B., Olaussen, S., Pedersen, J.H. and Backer-Owe, K. 2016. Novel proof of migrated petroleum in outcropping Mesozoic sedimentary rocks in Spitsbergen: Organic geochemical characterization and implications for regional exploration. Under review in the *Journal of Petroleum Geology*.
- Allen, P.A. and Allen J. R., 2013. *Basin Analysis: Principles and Application to Petroleum Play Assessment*. third Edition. John Wiley & Sons, Ltd., 619pp.
- Augustson, J.H., 1993. A method on classification of oil traps based on heavy oil content in cores with relevance to filling and drainage of Barents Sea oil-bearing structures. In: Vorren, T.O., Bergsager, E., Dahl-Stamnes, A., Holter, E., Johansen, B., Lie, E. and Lund, T.B (Eds.), *Arctic Geology and Petroleum Potential*. Norwegian Petroleum Society Special Publication, 2, 405–418.
- Baig, I., Faleide, J.I., Jahren, J. and Mondol, N.H., 2016. Cenozoic exhumation on the southwestern Barents Shelf: Estimates and uncertainties constrained from compaction and thermal maturity analyses. *Marine and Petroleum Geology*, 73, 105-130.
- Berglund, L.T., Augustson, J., Færseth, R., Gjelberg, J. and Ramberg-Moe, H., 1986. The evolution of the Hammerfest Basin. In: Spencer, A.M., Holter, E., Campbell, C.J., Hanslien, S.H., Nelson, P.H.H., Nysæther, E., and Ormaasen, E. G. (Eds.), *Habitat of Hydrocarbons on the Norwegian Continental Shelf*. London, Graham & Trotman, 319–338.
- Biddle, K.T. and Wielchowsky, C.C., 1994. Hydrocarbon Traps. In: Magoon, L.B. and Dow, W.G. (Eds.), *The petroleum system – from source to trap*. AAPG Memoir, 60, 219–235.

- Bjørlykke, K., 2015. *Petroleum Geoscience – From Sedimentary Environments to Rock Physics*. Springer Verlag Heidelberg, 662pp.
- Boulton, G.S., Caban, P.E. and Van GiJssel, K., 1995. Groundwater flow beneath ice sheets: Part I – Large scale patterns. *Quaternary Science Reviews*, 14, 545-562.
- Brekke, H., Sjulstad, H.I., Magnus, C. and William, R.W., 2001. Sedimentary environments offshore Norway – an overview. In: Martinsen, O.J. and Dreyer, T. (Eds.), *Sedimentary environments offshore Norway – Palaeozoic to Recent*. Norwegian Petroleum Society Special Publication, 10, 7–37.
- Brooks, J. and Welte, D., 1984. Introduction. In: Brooks, J. and Welte, D. (Eds.), *Advances in petroleum geochemistry Vol. 1*, 1–6.
- Bordenave, M.L., 1993. *Applied Petroleum Geochemistry*. Editions Technip, Paris, 524pp.
- Cavanagh, A.J., di Primio, R., Scheck-Wenderoth, M. and Horsfield, B., 2006. Severity and timing of Cenozoic exhumation in the southwestern Barents Sea. *Journal of the Geological Society*, 163, 761–774.
- Chew, K.J. and Arbouille, D., 2011. Hydrocarbon finds in the Arctic basins: discovery history, discovered resources and petroleum systems. In: Spencer, A.M., Embry, A.F., Gautier, D.L., Stoupakova, A.V. and Sørensen, K. (Eds.), *Arctic Petroleum Geology*. Geological Society, London, *Memoirs* 35, 131–144.
- Chen, J., Fu, J., Sheng, G., Liu, D. and Zhang, J., 1996. Diamondoid hydrocarbon ratios: novel maturity indices for highly mature crude oils. *Organic Geochemistry*, 25, 179–190.
- Christie, O.H., Esbensen, K., Meyer, T. and Wold, S., 1984. Aspects of pattern recognition in organic geochemistry. *Organic Geochemistry*, 6, 885-891.
- Corcoran, D.V. and Doré, A.G., 2002. Top seal assessment in exhumed basin settings - some insights from Atlantic margin and borderland basins. In: Koestler, A.G. and Hunsdale, R. (Eds.), *Hydrocarbon Seal Quantification*. Norwegian Petroleum Society Special Publication, 11, 89–109.
- Dalland, A.D., Worsley, D. and Ofstad, K., 1988. A lithostratigraphic scheme for the Mesozoic and Cenozoic succession offshore mid- and northern Norway. *Norwegian Petroleum Directorate Bulletin* 4, 65pp.
- Dahl, J.E., Moldowan, J.M., Peters, K.E., Claypool, G.E., Rooney, M.A., Michael, G.E., Mello, M.R. and Kohnen M.L., 1999. Diamondoid hydrocarbons as indicators of natural oil cracking. *Nature*, 399, 54–57.
- Demaison, G., 1984. The generative basin concept. In: Demaison, G. and Murris, R.J. (Eds.), *Petroleum geochemistry and basin evaluation*. AAPG Memoir, 35, 1–14.
- Dimakis, P., Braathen, B.I., Faleide, J.I., Elverhøi, A. and Gudlaugsson, S.T., 1998. Cenozoic erosion and the preglacial uplift of the Svalbard–Barents Sea region. *Tectonophysics*, 300, 311–327.
- di Primio, R., Dieckmann, V. and Mills, N., 1998. PVT and phase behaviour analysis in petroleum exploration. *Organic Geochemistry*, 29, 207-222.
- Doré, A.G., 1995. Barents Sea geology, petroleum resources and commercial potential. *Arctic*, 48, 207–221.
- Doré, A.G. and Jensen, L.N., 1996. The impact of late Cenozoic uplift and erosion on hydrocarbon exploration: offshore Norway and some other uplifted basins. *Global and Planetary Change*, 12, 415–436.
- Doré, A.G., Scotchman, I.C. and Corcoran, D., 2000. Cenozoic exhumation and prediction of the hydrocarbon system on the NW European margin. *Journal of Geochemical Exploration*, 69–70, 615–618.
- Doré, A.G., Corcoran, D.V. and Scotchman, I.C., 2002. Prediction of the hydrocarbon system in exhumed basins, and application to the NW European margin. In: Geological Society Special Publication, 196, 401–429.
- Dow, W.G., 1974. Application of oil correlation and source rock data to exploration in Williston basin. *AAPG Bulletin*, 58, 1253–1262.

- Downey, M.W., 1994. Hydrocarbon seal rocks. In: Magoon, L.B. and Dow, W.G. (Eds.), *The petroleum system – from source to trap*. AAPG Memoir, 60, 159–164.
- Dutta, S., Greenwood, P.F., Brocke, R., Schaefer, R.G. and Mann, U., 2006. New insights into the relationship between Tasmanites and tricyclic terpenoids. *Organic Geochemistry*, 37, 117–127.
- Ehrenberg, S.N., Nielsen, E.B., Svånå, T.A. and Stemmerik L., 1998. Depositional evolution of the Finnmark carbonate platform, Barents Sea: results from wells 7128/6-1 and 7128/4-1. *Norsk Geologisk Tidsskrift*, 78, 185–224.
- England, W.A., Mackenzie, A., Mann, D. and Quigley, T., 1987. The movement and entrapment of petroleum fluids in the subsurface. *Journal of the Geological Society*, 144, 327–347.
- England, W.A., 1994. Secondary migration and accumulation of hydrocarbons. In: Magoon, L.B. and Dow, W.G. (Eds.), *The petroleum system – from source to trap*. AAPG Memoir, 60, 211–217.
- Espitalie, J., Laporte, L.J., Madec, M., Marquis, F., Leplat, P., Paulet, J. and Boutefeu, A., 1977. Methode rapide de caracterisation des roches mères, de leur potential petrolier et de leur degre d'evolution. *Revue de l'Institut Francais du Pétrole* 32, 23–42.
- Faleide, J.I., Gudlaugsson, S.T. and Jacquart, G., 1984. Evolution of the western Barents Sea. *Marine and Petroleum Geology*, 1, 123–150.
- Faleide, J.I., Tsikalas, F., Breivik, A.J., Mjelde, R., Ritzmann, O., Engen, O., Wilson, J. and Eldholm, O., 2008. Structure and evolution of the continental margin off Norway and the Barents Sea. *Episodes*, 31, 82–90.
- Farrimond, P., Bevan, J.C. and Bishop, A.N., 1999. Tricyclic terpane maturity parameters: response to heating by an igneous intrusion. *Organic Geochemistry*, 30, 1011–1019.
- Forsberg, C.F., 1996. Possible consequences of glacially induced groundwater flow. *Global and Planetary Change*, 12, 387–396.
- Gabrielsen, R.H., Faereth, R.B., Jensen, L.N., Kvalheim, J.E. and Riis, F., 1990. Structural Elements of the Norwegian Continental Shelf Pt. 1. The Barents Sea Region. *Norwegian Petroleum Directorate Bulletin*, 6, 47pp.
- Gautier, D.L., Bird, K.J., Charpentier, R.R., Grantz, A., Houseknecht, D.W., Klett, T.R., Moore, T.E., Pitman, J.K., Schenk, C.J., Schuenemeyer, J.H., Sørensen, K., Tennyson, M.E., Valin, Z.C. and Wandrey, C.J., 2009. Assessment of Undiscovered Oil and Gas in the Arctic. *Science*, 324, 1175–1178.
- Green, P.F. and Duddy, I.R., 2010. Synchronous exhumation events around the Arctic including examples from Barents Sea and Alaska North Slope. In: Vinning, B.A. and Pickering, S.C. (Eds.), *Petroleum Geology: From Mature Basins to New Frontiers – Proceedings of the 7<sup>th</sup> Petroleum Geology Conference*, 633–644.
- Gussow, W.C., 1954. Differential entrapment of oil and gas: a fundamental principle. *AAPG Bulletin*, 38, 816–853.
- Head, I.M., Jones, D.M. and Larter, S.R., 2003. Biological activity in the deep subsurface and the origin of heavy oil. *Nature*, 426, 344–352.
- Henriksen, E., Ryseth, A.E., Larssen, G.B., Heide, T., Rønning, K., Sollid, K. and Stoupakova, A.V., 2011a. Tectonostratigraphy of the greater Barents Sea: implications for petroleum systems. In: Spencer, A.M., Embry, A.F., Gautier, D.L., Stoupakova, A.V. and Sørensen, K. (Eds.), *Arctic Petroleum Geology*. Geological Society, London, Memoirs 35, 163–195.
- Henriksen, E., Bjørnseth, H.M., Hals, T.K., Heide, T., Kiryukhina, T., Kløvjan, O.S., Larssen, G. B., Ryseth, A.E., Rønning, K., Sollid, K. and Stoupakova, A.V., 2011b. Uplift and erosion of the greater Barents Sea: impact on prospectivity and petroleum systems. In: Spencer, A.M., Embry, A.F., Gautier, D.L., Stoupakova, A.V. and Sørensen, K. (Eds.), *Arctic Petroleum Geology*. Geological Society, London, Memoirs 35, 271–281.
- Holba, A.G., Dzou, L.I.P., Wood, G.D., Ellis, L., Adam, P., Schaeffer, P., Albrecht, P., Greene, T. & Hughes, W.B. 2003. Application of tetracyclic polyprenoids as indicators of input from fresh-brackish water environments. *Organic Geochemistry*, 34, 441–469.

- Horsfield, B. and Rullkötter, J., 1994. Diagenesis, catagenesis and Metagenesis of organic matter. In: Magoon, L.B. and Dow, W.G. (Eds.), *The petroleum system – from source to trap*. AAPG Memoir, 60, 189–199.
- Huc, A.Y. and Vially, R., 2012. New perspectives for fossil fuels: hydrocarbons in unconventional settings. In: Saulnier, J.B. and Varella, M.D. (Eds.), *Global Change, Energy Issues and Regulation Policies*. Springer Netherlands, 47–75.
- Huc, A.Y., 2013. *Geochemistry of Fossil Fuels. From Conventional to Unconventional Hydrocarbon Systems*. Edition TECHNIP, Paris, 254pp.
- Hunt, J.M., Stewart, F. and Dickey, P.A., 1954. Origin of hydrocarbons of Unita Basin, Utah. *AAPG Bulletin*, 38, 1671–1688.
- Hunt, J.M., 1979. *Petroleum geochemistry and geology*. W.H. Freeman and Company, San Francisco, 617pp.
- Hunt, J.M., 1995. *Petroleum geochemistry and geology*, 2<sup>nd</sup> edition. W.H. Freeman and Company, San Francisco, 743pp.
- Hunt, J.M., Philp, R.P. and Kvenvolden, K.A., 2002. Early developments in petroleum geochemistry. *Organic Geochemistry*, 33, 1025–1052.
- Høy, T. and Lundschie, B.A., 2011. Triassic deltaic sequences in the northern Barents Sea. In: Spencer, A.M., Embry, A.F., Gautier, D.L., Stoupakova, A.V. and Sørensen, K. (Eds.), *Arctic Petroleum Geology*. Geological Society, London, Memoirs 35, 249–260.
- Jakobsson, M., et al. 2012. The International Bathymetric Chart of the Arctic Ocean (IBAO) Version 3.0. *Geophysical Research Letters*, 39, L12609.
- Johansen, S.E., Ostist, B.K., Birkeland, Ø., Fedorovsky, Y.F., Martirosjan, V.N., Christensen, O.B., Cheredeev, S.I., Ignatenko, E.A. and Margulis, L.S., 1993. Hydrocarbon potential in the Barents Sea region: play distribution and potential. In: Vorren, T.O., Bergsager, E., Dahl-Stamnes, Ø.A., Holter, E., Johansen, B., Lie, E. and Lund, T.B. (Eds.), *Arctic Geology and Petroleum Potential: Norwegian Petroleum Society, Special Publication*, 2, 273–320.
- Jones, D.M., Head, I.M., Gray, N.D., Adams, J.J., Rowan, A.K., Aitken, C.M., Bennett, B., Huang, H., Brown, A., Bowler, B.F.J., Oldenburg, T., Erdmann, M. and Larter, S.R., 2008. Crude-oil biodegradation via methanogenesis in subsurface petroleum reservoirs. *Nature*, 451, 176–181.
- Kaminsky, V.D., Suprunenko, O.I. and Suslova, V.V., 2011. Oil and gas potential of the Russian Arctic Shelf and palaeogeographic mapping of the Barents Sea. In: Spencer, A.M., Embry, A.F., Gautier, D.L., Stoupakova, A.V. and Sørensen, K. (Eds.), *Arctic Petroleum Geology*. Geological Society, London, Memoirs 35, 345–352.
- Karlsen, D.A., Nedkvitne, T., Larter, S.R. and Bjørlykke, K., 1993. Hydrocarbon composition of authigenic inclusions: Application to elucidation of petroleum reservoir filling history. *Geochimica et Cosmochimica Acta*, 57, 3641–3659.
- Karlsen, D.A., Skeie, J.E., Backer-Owe, K., Bjørlykke, K., Olstad, R., Berge, K., Cecchi, M., Vik, E. and Schaefer, R.G., 2004. Petroleum migration, faults and overpressure. Part II. Case history: The Haltenbanken Petroleum Province, offshore Norway. In: Cubitt, J.M., England, W.A. and Larter, S.R. (Eds.), *Understanding petroleum reservoirs: Towards an integrated reservoir engineering and geochemical approach*. London, Geological Society Special Publications, 237, 305–372.
- Karlsen, D.A. and Skeie, J.E., 2006. Petroleum Migration, Faults and Overpressure, Part I: Calibrating Basin Modelling using Petroleum in Traps - a Review. *Journal of Petroleum Geology*, 29, 227–256.
- Karlsen, D.A., 2014. Source Rocks and Migration of Oil and Gas on Svalbard and in the Barents Sea. Hydrocarbon Habitats Seminar “Source Rocks in the Barents Sea”, March 13, Oslo, Norway
- Killops, S. and Killops, V., 2005. *Introduction to Organic Geochemistry* 2<sup>nd</sup> edition. Blackwell Publishing, 393pp.

- Kjemperud A. and Fjeldskaar, W., 1992. Pleistocene glacial isostasy – implications for petroleum geology. In: Larsen, R.M., Brekke, H., Larsen, B.T. and Talleraas, E. (Eds.), *Structural and Tectonic Modelling and its Applications to Petroleum Geology*. Norwegian Petroleum Society Special Publication, 1, 187-195.
- Klett, T.R., Gautier, D.L., Bird, K.J., Charpentier, R.R., Houseknecht, D.W., Moore, T.E., Pitman, J.K., Schenk, C.J., Tennyson, M.E. and Wandrey, C.J., 2009. Assessment of Undiscovered Petroleum Resources of the Barents Sea Shelf, v. 3037, United States Geological Survey, 3pp.
- Knutsen, S.M., Augustson, J.H. and Haremo, P. 2000. Exploring the Norwegian part of the Barents Sea – Norsk Hydro's lessons from nearly 20 years of experience. In: Ofstad, K., Kittilsen, J.E. and Alexander-Marrack, P. (Eds.), *Improving the exploration process by learning from the past*: Norwegian Petroleum Society Special Publication, 9, 99–112.
- Koevoets, M.J., Abay, T.B., Hammer, Ø. And Olaussen, S., 2016. High-resolution organic carbon-isotope stratigraphy of the Middle Jurassic–Lower Cretaceous Agardhfjellet Formation of central Spitsbergen, Svalbard. *Palaeogeography, Palaeoclimatology, Palaeoecology*, 449, 266-274.
- Krajewski, K.P., 2013. Organic matter–apatite–pyrite relationships in the Botneheia Formation (Middle Triassic) of eastern Svalbard: Relevance to the formation of petroleum source rocks in the NW Barents Sea shelf. *Marine and Petroleum Geology*, 45, 69-105.
- Laberg, J.S., Andreassen, K. and Vorren, T.O., 2012. Late Cenozoic erosion of the high-latitude southwestern Barents Sea shelf revisited. *GSA Bulletin*, 124, 77-88.
- Larsen, R.M., Fjæran, T. and Skarpnes, O., 1993. Hydrocarbon potential of the Norwegian Barents Sea based on recent well results. In: Vorren, T.O., Bergsager, E., Dahl-Stamnes, Ø.A., Holter, E., Johansen, B., Lie, E., and Lund, T.B. (Eds.), *Arctic Geology and Petroleum Potential*: Norwegian Petroleum Society, Special Publication, 2, 321–331.
- Larssen, G.B., Elvebakk, G., Henriksen, L.B., Kristensen, S.E., Nilsson, I., Samuelsberg, T.J., Svånå, T.A., Stemmerik, L. and Worsley, D., 2002. Upper Palaeozoic lithostratigraphy of the Southern Norwegian Barents Sea. *Norges Geologiske Undersøkelser Bulletin* 444, 72pp.
- Leith, T.L., Weiss, H.M., Mørk, A., Århus, N., Elvebakk, G., Embry, A.F., Brooks, P.W., Stewart, K.R., Pchelina, T.M., Bro, E.G., Verba, M.L., Danyushevskaya, A. and Borisov, A.V., 1993. Mesozoic hydrocarbon source-rocks of the Arctic region. In: Vorren, T.O., Bergsager, E., Dahl-Stamnes, O.A., Holter, E., Johansen, B., Lie, E. and Lund, T.B.S. (Eds.), *Arctic Geology and Petroleum Potential*. Norwegian Petroleum Society Special Publication, 2, 1–25.
- Lerch, B. and Karlsen, D.A., 2015. Migration, mixing and alteration modes in Barents Sea petroleums – A regional examination from a geochemical perspective. Seminar “The Jurassic and Triassic Petroleum Systems of the Barents Sea”, 28.04. – 30.04.2015, Longyearbyen, Svalbard, Norway.
- Lerch, B., Karlsen, D.A., Matapour, Z., Seland, R. and Backer-Owe, K., 2016a. Organic geochemistry of Barents Sea petroleum: Thermal maturity and alteration and mixing processes in oils and condensates. *Journal of Petroleum Geology*, 39, 125–147.
- Lerch, B. and Karlsen, D.A., 2016b. Ages and Depositional Environments of Barents Sea Petroleums. AAPG and SEG, International Conference and Exhibition, 03.04. – 06.04.2016, Barcelona, Spain.
- Lerch, B., Karlsen, D.A., Seland, R. and Backer-Owe, K., 2016c. Depositional environment and age determination for inferred source rocks from Barents Sea petroleums. *Journal of Petroleum Geoscience*, Published Online First, doi: 10.1144/petgeo2016-039
- Lerche, I., Yu, Z., Tørudbakken, B. and Thomsen, R.O., 1997. Ice loading effects in sedimentary basins with references to the Barents Sea. *Marine and Petroleum Geology*, 14, 277-338.
- Lundschien, B.A., Høy, T. and Mørk, A., 2014. Triassic hydrocarbon potential in the Northern Barents Sea; integrating Svalbard and stratigraphic core data. *Norwegian Petroleum Directorate Bulletin*, 11, 3–20.
- Magoon, L.B. and Dow, W.G., 1994. The petroleum system. In: Magoon, L.B. and Dow, W.G. (Eds.), *The petroleum system – from source to trap*. AAPG Memoir, 60, 3–24.

- Matapour, Z. and Karlsen, D.A., 2016. Geochemical characteristics of the Skrugard oil discovery Barents Sea, Arctic Norway: A "palaeo-biodegraded - gas reactivated" hydrocarbon accumulation. (submitted to the Journal of Petroleum Geology).
- Meissner, F.F., 1984. Petroleum geology of the Bakken Formation, Williston basin, North Dakota and Montana. In: Demaison, G. and Murris, R.J. (Eds.), Petroleum geochemistry and basin evaluation. AAPG Memoir, 35, 159–179.
- Murillo, W.A., Vieth-Hillebrand, A., Horsfield, B. and Wilkes, H., 2016. Petroleum source, maturity, alteration and mixing in the southwestern Barents Sea: New insights from geochemical and isotope data. *Marine and Petroleum Geology*, 70, 119–143.
- Mørk, A., Knarud, R. and Worsley, D., 1982. Depositional and diagenetic environments of the Triassic and Lower Jurassic succession of Svalbard. In: Embry, A.F. and Balkwill, H.R. (Eds.), Arctic Geology and Geophysics, Canadian Society of Petroleum Geologists Memoir 8, 371–398.
- Mørk, A., Embry, A.F. and Weitschat, W., 1989. Triassic transgressive-regressive cycles in the Sverdrup Basin, Svalbard and the Barents Shelf. In: Collinson, J.D. (Ed.), Correlation in Hydrocarbon Exploration, Norwegian Petroleum Society, Graham & Trotman, 113–130.
- Mørk, A., Vigran, J.O., Korcinskaja, M.V., Pcelina, T.M., Fefilova, L.A., Vavilov, M.N. and Weitschat, W., 1993. Triassic source rocks in Svalbard, the Arctic Soviet Islands and the Barents Shelf: bearing on their correlations. In: Vorren, T., Bergsager, E., Dahl-Stamnes, Ø.A., Holter, E., Johansen, B., Lie, E. and Lund, T.B. (Eds.), Arctic Geology and Petroleum Potential, Norwegian Petroleum Society Special Publications, 2, 455–477.
- Mørk, A. and Bjørøy, M., 1984. Mesozoic source rocks on Svalbard. In: Spencer, A.M. et al. (Eds.), Petroleum geology of the Northwest European Margin. Norwegian Petroleum Society, Graham & Trotman, London, 371–382.
- Nansen, F., 1904. The bathymetrical features of the north polar seas: with a discussion of the continental shelves and previous oscillations of the shore-line, The Norwegian Polar Expeditions 1893-1896. Scientific Results 4, Jacob Dubwads Forlag, Kristiania (Oslo), 232pp.
- Norlex (Norwegian Interactive Offshore Stratigraphic Lexicon), 2015. Lithostratigraphic wall chart, offshore Norway. <http://nhm2.uio.no/norlex/> (accessed October 2015).
- Norwegian Petroleum Directorate, 2015. Norwegian Petroleum Directorate Factpages. <http://factpages.npd.no/factpages/Default.aspx?culture=no> (accessed September 2015).
- Norwegian Petroleum Directorate, 2016. CO2 Storage Atlas Barents Sea. <http://www.npd.no/Global/Norsk/2-Tema/Lagring-og-bruk-av-CO2/CO2-ATLAS-Barents-Sea.pdf> (accessed January 2016).
- Nyland, B., Jensen, L.N., Skagen, J., Skarpnes, O. and Vorren, T., 1992. Tertiary uplift and erosion in the Barents Sea: Magnitude, timing and consequences. In: Larsen, R.M., Brekke, H., Larsen, B. T. and Talleraas, E. (Eds.), Structural and Tectonic Modelling and its Application to Petroleum Geology, Norwegian Petroleum Society Special Publications, 1, 153–162.
- Nøttvedt, A., Livbjerg, F., Midbøe, P.S. and Rasmussen, E., 1993. Hydrocarbon potential of the Central Spitsbergen Basin. In: Vorren, T., Bergsager, E., Dahl-Stamnes, Ø.A., Holter, E., Johansen, B., Lie, E. and Lund, T.B. (Eds.), Arctic Geology and Petroleum Potential, Norwegian Petroleum Society Special Publications, 2, 333–361.
- Ohm, S.E., Karlsen, D.A. and Austin, T.J.F., 2008. Geochemically driven exploration models in uplifted areas: Examples from the Norwegian Barents Sea. AAPG Bulletin, 92, 1191–1223.
- Ostanin, I., Anka, Z., di Primio, R. and Bernal, A., 2012. Identification of a large Upper Cretaceous polygonal fault network in the Hammerfest Basin: Implications on the reactivation of regional faulting and gas leakage dynamics, SW Barents Sea. *Marine and Petroleum Geology*, 332, 109–125.
- Ourisson, G., Albrecht, P. and Rohmer, M., 1982. Predictive microbial biochemistry – from molecular fossils to prokaryotic membranes. *Trends in Biochemical Sciences*, 7, 236–239.

- Palacas, J.G., Anders, D.E. and King, J.D., 1984. South Florida Basin. Prime example of carbonate source rocks of petroleum. In: Palacas, J.G. (Ed.) *Petroleum geochemistry and source rock potential of carbonate rocks*. American Association of Petroleum Geologists Studies in Geology, 18, 71-96.
- Palmer, S.E., 1993. Effect of biodegradation and water washing on crude oil composition. In: Engel, M.H. and Macko, S.A. (Eds.) *Organic Geochemistry – Principles and Applications*, Plenum Press New York, 511-534.
- Pedersen, J.H., Karlsen, D.A., Brunstad, H. and Lie, J.E., 2005. Oil and gas of the Norwegian Barents Sea: AAPG Annual Convention 2005, June 19–22, Calgary, Alberta, Canada.
- Pedersen, J.H., 2014. Mapping of petroleum systems in the south-western Barents Sea. Arctic Conference Days 2014, June 2-6, Tromsø, Norway.
- Peters, K.E. and Cassa, M.R., 1994. Applied source rock geochemistry. In: Magoon, L.B. and Dow, W.G. (Eds.), *The petroleum system – from source to trap*. AAPG Memoir, 60, 93–120.
- Peters, K.E. and Fowler, M.G., 2002. Applications of petroleum geochemistry to exploration and reservoir management. *Organic Geochemistry*, 33, 5–36.
- Peters, K.E., Walters, C.C. and Moldowan, J.M., 2005. *The Biomarker Guide*. Cambridge University Press, 1155pp.
- Philp, R.P. and Gilbert, T.D., 1986. Biomarker distributions in Australian oils predominantly derived from terrigenous source material. In: Leythausen D. and Rullkötter, J. (Eds.), *Advances in Organic Geochemistry 1985*, Pergamon Press, 73-84.
- Revill, A.T., Volkman, J.K., O’Leary, T., Summons, R.E., Boreham, C.J., Banks, M.R. and Denwer, K., 1994. Hydrocarbon biomarkers, thermal maturity, and depositional setting of tasmanite oil shales from Tasmania, Australia. *Geochimica and Cosmochimica Acta*, 58, 3803-3822.
- Riis, F., Lundschieen, B.A., Høy, T., Mørk, A. and Mørk, M.B.E., 2008. Evolution of the Triassic shelf in the northern Barents Sea region, *Polar Research*, 27, 318–338.
- Riis, F. and Fjeldskaar, W., 1992. On the magnitude of the late Tertiary and Quaternary erosion and its significance for the uplift of Scandinavia and the Barents Sea. In: Larsen, R.M., Brekke, H., Larsen, B. T. and Talleraas, E. (Eds.), *Structural and Tectonic Modelling and its Application to Petroleum Geology*. Norwegian Petroleum Society Special Publications, 1, 163–185.
- Sales, J.K., 1997. Seal Strength vs. Trap Closure - A Fundamental Control on the Distribution of Oil and Gas. In: Surdam, R.C. (Ed.), *Seals, Traps, and the Petroleum System*, AAPG Memoir, 67, 57–83.
- Schulz, L., Wilhelms, A., Rein, E. and Steen, S., 2001. Application of diamondoids to distinguish source rock facies. *Organic Geochemistry*, 32, 365–375.
- Silverman, S.R., 1965. Migration and Segregation of Oil and Gas. In Young, A. and Gally, J.E. (Eds.), *Fluids in Subsurface Environments*, AAPG Memoir, 4, 53–65.
- Simoneit, B.R., Schoell, M., Dias, R.F. and Aquino Neto, F.R., 1993. Unusual carbon isotope compositions of biomarker hydrocarbons in a Permian tasmanite. *Geochimica et Cosmochimica Acta*, 57, 4205-4211
- Stainforth, J.G., 2009. Practical kinetic modeling of petroleum generation and expulsion. *Marine and Petroleum Geology*, 26, 552–572.
- Stemmerik, L. and Worsley, D., 2005. 30 years on - Arctic Upper Palaeozoic stratigraphy, depositional evolution and hydrocarbon prospectivity. *Norwegian Journal of Geology*, 85, 151–168.
- Stewart, D.J., Berge, K. and Bowlin, B., 1995. Exploration trends in the Southern Barents Sea. In: Hanslien, S. (Ed.), *Petroleum Exploration and Exploitation in Norway*, Norwegian Petroleum Society Special Publication, 4, 253–276.
- Tissot, B.P., Pelet, R. and Ungerer, P., 1987. Thermal history of sedimentary basins, maturation indices, and kinetics of oil and gas generation. *AAPG Bulletin*, 71, 1445–1466.

- Tissot, B.P. and Welte, D.H., 1984. Petroleum Formation and Occurrence, 2<sup>nd</sup> edition. Springer-Verlag, New York, 699pp.
- Ulmishek, G., 1986. Stratigraphic aspects of petroleum resource assessment. In: Rice, D.D. (Ed.), Oil and gas assessment – methods and applications. AAPG Studies in Geology, 21, 59–68.
- U.S. Energy Information Administration, 2014. Annual Energy outlook 2014. <http://www.eia.gov/forecasts/aeo/> (accessed September, 2015).
- Vandenbroucke, M. and Largeau, C., 2007. Kerogen origin, evolution and structure. Organic Geochemistry, 38, 719–833.
- Van Koeverden, J.H., Karlsen, D.A., Schwark, L., Chpitsglouz, A. and Backer-Owe, K., 2010. Oil-Prone Lower Carboniferous Coals in the Norwegian Barents Sea: Implications for a Palaeozoic Petroleum System. Journal of Petroleum Geology, 33, 155–181.
- Vigran, J.O., Mørk, A., Forsberg, A.W., Weiss, H.M. and Weitschat, W., 2008. Tasmanites-algae contributors to the Middle Triassic hydrocarbon source rocks of Svalbard and the Barents Shelf. Polar Research 27, 298–317.
- Vorren, T.O., Richardsen, G. and Knutsen, S.M., 1991. Cenozoic erosion and sedimentation in the western Barents Sea. Marine and Petroleum Geology, 8, 317–340.
- Weiss, H.M., Wilhelms, A., Mills, N., Scotchmer, J., Hall, P.B., Lind, K. and Brekke, T., 2000. NIGOGA—The Norwegian industry guide to organic geochemical analyses (Online) Edition 4.0: Published by Norsk Hydro, Statoil, Geolab Nor, SINTEF Petroleum Research and the Norwegian Petroleum Directorate, 102 pp., <http://www.npd.no/engelsk/nigoga/default.htm> (accessed July 03, 2013).
- Wenger, L.M., Davis, C.L. and Isaksen, G.H., 2002. Multiple controls on petroleum biodegradation and impact on oil quality. SPR Reservoir Evaluation and Engineering, 5, 375–383.
- Wilhelms, A., Larter, S.R., Head, I., Farrimond, P., di Primio, R. and Zwach, C., 2001. Biodegradation of oil in uplifted basins prevented by deep-burial sterilization. Nature, 411, 1034–1037.
- Worsley, D., 2008. The post Caledonian development of Svalbard and the western Barents Sea. Polar Research, 27, 298–317.
- Xu, G., Hannah, J.L., Stein, H.J., Bingen, B., Yang, G., Zimmermann, A., Weitschat, W., Mørk, A. and Weiss H.M., 2009. Re-Os geochronology of Arctic black shales to evaluate the Anisian-Ladinian boundary and global faunal correlations. Earth and Planetary Science Letters, 288, 581–587.
- Ziegler, P.A., 1988. Evolution of the Arctic-North Atlantic and the Western Tethys. AAPG Memoir, 43, 198pp.



## Appendix

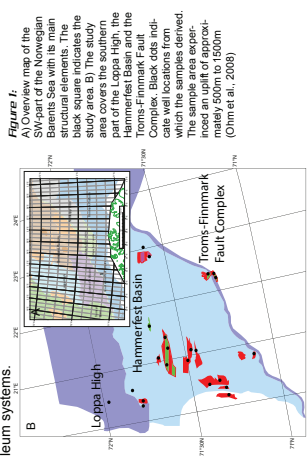
### Poster 1

Lerch, B., Karlsen, D.A. and Duggan, D. 2014. Migration and Alteration Processes in Barents Sea Oils and Condensates – A Geochemical Approach to improved Petroleum System Understanding. 76th EAGE Conference & Exhibition, 16.06. – 19.06. 2014, Amsterdam, The Netherlands.



## INTRODUCTION

Repeated uplift and erosion of the Barents Sea might play a crucial role in the distribution, alteration and composition of accumulated hydrocarbons. Commonly biomarkers are used to infer post-entrapment alteration or migration induced alteration processes in oil and gas. Oil-gas/condensate correlation studies. However, the concentration of the biomarker compounds decreases with increasing maturity and biomarkers can almost be absent in high maturity oils and condensates. Here, the use of light hydrocarbons (LHC) is of greatest importance as these make up a significant volume of oil and gas condensates (England et al., 1987) with up to 16mol% of a standard 0.3kg/kg North Sea oil. Furthermore represent LHC a highly mobile phase, which allows an insight of recent migration processes. In this context, special focus has to be brought on cap-rock properties as they play a critical role in petroleum systems.

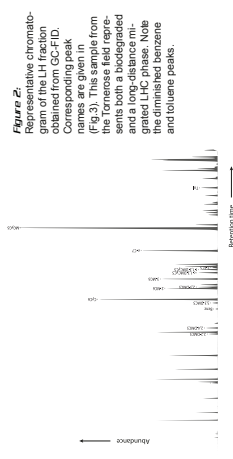


## OBJECTIVES

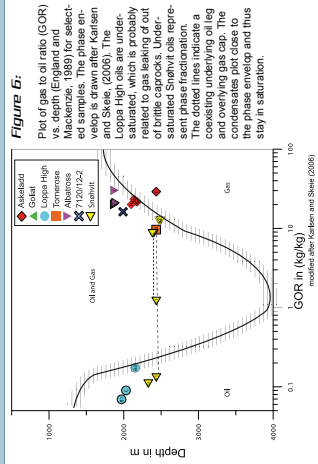
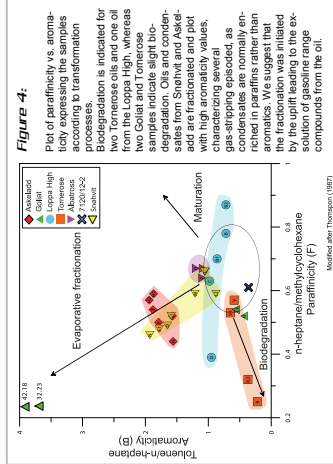
This study examines oil and gas/condensate samples from the Hammerfest Basin and the Loppa High (Figure 1) in terms of biodegradation, evaporative fractionation and long-distance migrated hydrocarbon phases, whereby the properties of seal-rocks may play a crucial role.

## MATERIALS & METHODS

Geochemical analysis was carried out on 32 oil and condensate samples from the Hammerfest Basin and Loppa High. The parameters are based on results obtained from Gas-Chromatography - Flame Ionization Detection (GC-FID), which allows a near perfect separation of the gasoline range compounds (n-C4-n-C8) (Fig 2). Peak areas were determined and LHC parameter ratios were calculated as suggested by Thompson (1987) and Halpern (1995).



## RESULTS



## CONCLUSIONS

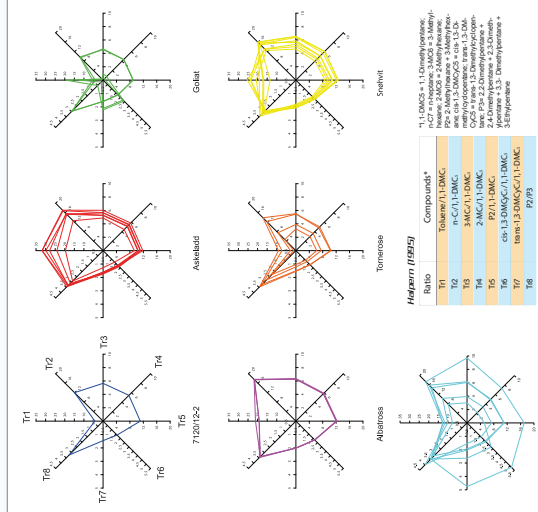
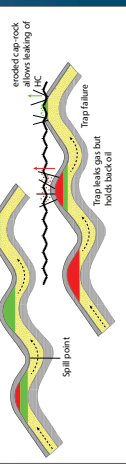
Biodegradation occurs only on the margins of the Hammerfest Basin where tectonized cap-rocks are present favoring the intrusion of water or traps are exposed closer to aquifers (Fig. 8A).

Fractionated oils and condensates occur mainly in the Hammerfest Basin and derived locally through vertical migration (Fig. 8B).

Water soluble aromatic compounds (toluene, benzene) are stripped out in effective carrier systems indicating long-distance migration (Fig. 8C).

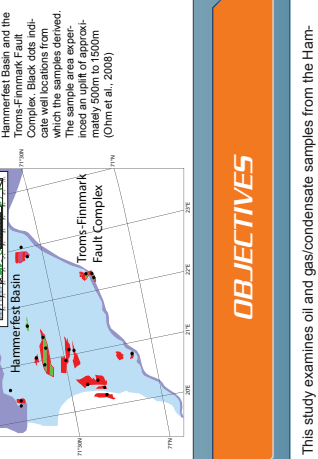
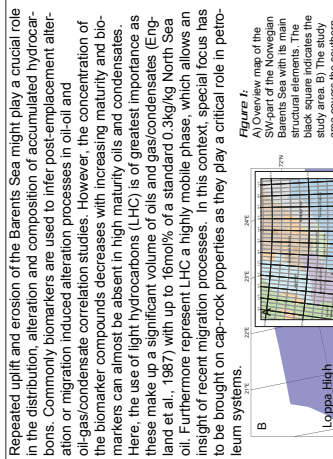
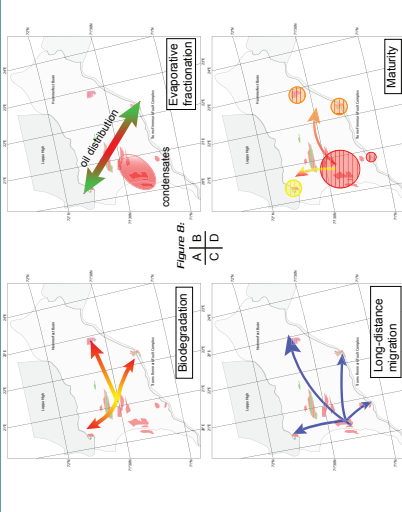
The margins around the Hammerfest Basin act like a center of attraction to migrating hydrocarbons (Fig. 8B/C).

Cap-rock properties play a crucial role in distribution and composition of petroleum. Uplift induced expansion of gas pushes the oil downwind below closure leading to remigration. The type of the cap-rock determines the petroleum phase in the trap.



C7-Oil Transformation Diagrams (C7-OTSD) after Halpern (1995). Axes are representatively labeled on the first C7-OTSD. Low T1 values indicate long-distance migration characterized by low bitumen content. Water soluble aromatics get 'stripped out' in effective carrier systems. Biodegradation is indicated by diminished T1-T15 and T17-T19 values, with T18 the most resistant against biodegradation. Two Loppa High samples (LH1 and LH2) represent biodegradation. Gas and condensates from Shavitt and Asakelid are suggested to be derived from a local source. Overall high values for one Loppa High sample indicates a fresh gas charge which masks the paleo-signal.

## SUMMARY



## REFERENCES

Chung, H. M., C. G. Walters, S. Buck, and Bingham, G. (1998) Mixed signals of the source and thermal maturity for petroleum accumulations from light hydrocarbons: an example of the Beryl field. *Organic Geochemistry*, v. 29, no. 1, p. 381-396.

England, W.A., Mackenzie, A.S., Mann, D.M., and Outcrop, T.M. (1987) The movement and entrapment of petroleum fluids in the subsurface. *Journal of the Geological Society*, 144, 1-14.

England, W.A., and Mackenzie, A.S. (1989) Some aspects of the organic geochemistry of petroleum fluids. *Geologische Rundschau*, v. 78, no. 1, 291-303.

Hajpern, H.J. (1995) Development and applications of light hydrocarbon based star diagrams. *AAPG Bulletin*, 79 (6), 801-815.

Karlstrom, B., and E. (2008) Petroleum Migration: Faults and Overpressure. Part I. Call for a new paradigm. *Journal of Petroleum Geology*, 29 (3), 227-255.

Ohm, S.E., Karlstrom, D.A., and Austin, T.J.F. (2008) Geochemically driven exploration models in up lifted areas. Examples from the Norwegian Barents Sea. *AAPG Bulletin*, 92 (9), 1191-1223.

Thompson, J.K. (1987) Seal Strength vs. Trap Closure - A Fundamental Control on the Distribution of Oil and Gas. In R.C. Suttman, ed., *AAPG Memoir*, v. 67, 57-83.



## Poster 2

Lerch, B., Karlsen, D.A. and Duggan, D., 2014. The Light Hydrocarbon Paradox of the Barents Sea – Light Hydrocarbon Correlation- & Transformation Parameters in Barents Sea Oils and Condensates. NGF Arctic Energy Conference, 04.06. – 05.06.2014, Tromsø, Norway.





UiO  
University of Oslo

NORECO

# The Light Hydrocarbon Paradox of the Barents Sea- Light Hydrocarbon Correlation- & Transformation-Parameters in Barents Sea Oils & Condensates

Benedikt Lerch<sup>1\*</sup>, Dag A. Karlsen<sup>1</sup>, Reinert Seland<sup>2</sup>, Tesfamariam B. Abay<sup>1</sup> & Kristian Backer-Owe<sup>1</sup>

<sup>1</sup>Department of Geosciences, University of Oslo, P.O. Box 1047 Blindern, N-0316 Oslo, Norway; <sup>2</sup>Noreco, Verksgata 1A 4013 Stavanger; \* benedikt.lerch@geo.uio.no



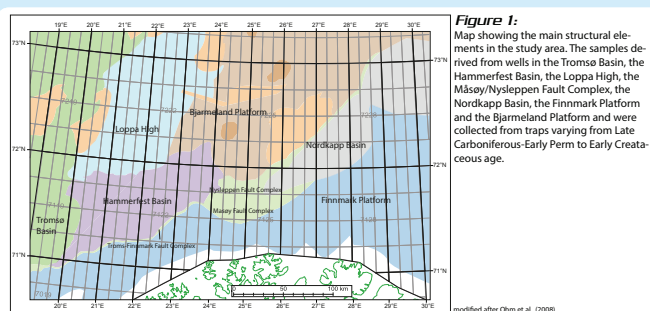
## Introduction

Cenozoic uplift and erosion are thought to have essential influence on the redistribution, composition and alteration of generated hydrocarbons in the Barents Sea. As the Barents Sea represents an overfilled multiple source rock basin (Ohm et al., 2008), geochemical investigation of oil and gas/condensate samples will improve our understanding of the petroleum systems.

This study focusses on the light hydrocarbon (LHC) fraction as these compounds make up significant volumes of oils/condensates, are the most mobile and recently migrated, but also the easiest lost compounds of petroleum. LHC thus provide a recent and dynamic insight into migration and alteration processes.

Compared to commonly applied biomarkers from the  $nC_{15}+$  range, LHC still hold valuable information of alteration even in high mature samples. Post emplacement alteration such as evaporative fractionation, biodegradation and water-washing/long-distance migration were found to occur in the LHC of the samples.

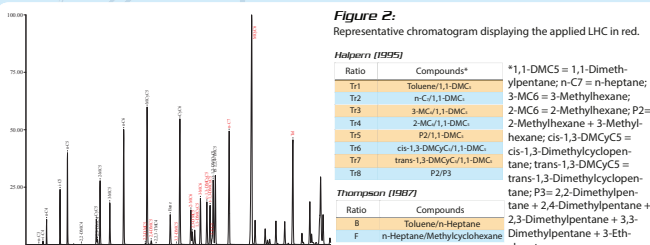
Besides geochemical practice, fundamental geological aspects as proposed by Gussow (1954) and Silverman (1965) were adapted to explain the distribution and composition of the samples. Whereas brittle/thin/silty cap-rocks hold back oil and leak gasoline range compounds, tight cap-rocks hold back both phases (Sales, 1997; Karlsen and Skeie, 2006).



**Figure 1:** Map showing the main structural elements in the study area. The samples derived from wells in the Tromsø Basin, the Hammerfest Basin, the Loppa High, the Måsøy/Nysleppen Fault Complex, the Nordkapp Basin, the Finnmark Platform and the Bjarmeland Platform and were collected from traps varying from Late Carboniferous-Early Perm to Early Cretaceous age.

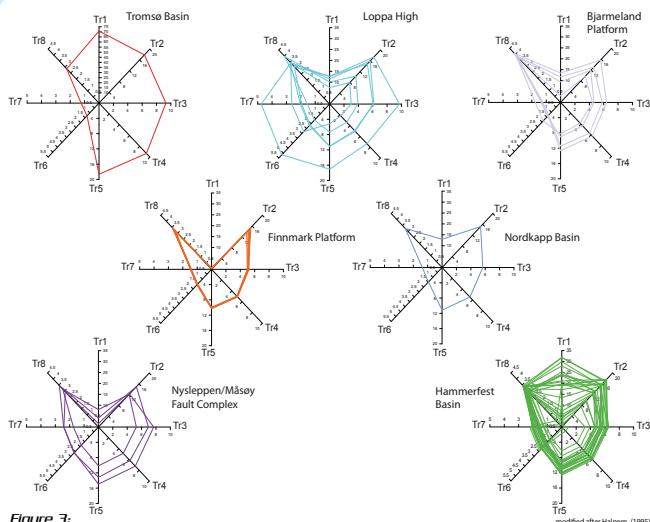
## Methods

Fourty-six oil and condensate samples from the Loppa High, the Hammerfest Basin, the Måsøy/Nysleppen Fault Complex, the Bjarmeland Platform, the Finnmark Platform and the Nordkapp Basin were geochemically investigated. LHC parameters as recommended by Thompson (1987) and Halpern (1995) (Fig.2) were calculated based on measured peak heights derived from gas chromatography-flame ionization detection (GC-FID).



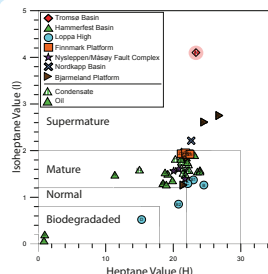
**Figure 2:** Representative chromatogram displaying the applied LHC in red.   
Halpern (1995)   
Ratio Compounds\*   
Tr1 Toluene/1,1-DMC;   
Tr2 n-C7/1,1-DMC;   
Tr3 3-MC/1,1-DMC;   
Tr4 2-MC/1,1-DMC;   
Tr5 P2/1,1-DMC;   
Tr6 cis-1,3-DMC/C7/1,1-DMC;   
Tr7 trans-1,3-DMC/C7/1,1-DMC;   
Tr8 P2/P3   
Thompson (1987)   
Ratio Compounds   
B Toluene/n-Heptane   
F n-Heptane/Methylcyclohexane   
\*1,1-DMC = 1,1-Dimethylpentane; n-C7 = n-Heptane; 3-MC = 3-Methylhexane; 2-MC = 2-Methylhexane; P2 = 2-Methylhexane + 3-Methylhexane; cis-1,3-DMC = cis-1,3-Dimethylcyclopentane; trans-1,3-DMC = trans-1,3-Dimethylcyclopentane; P3 = 2,2-Dimethylpentane + 2,4-Dimethylpentane + 3,3-Dimethylpentane + 3-Ethylpentane

## Results & Discussion - I

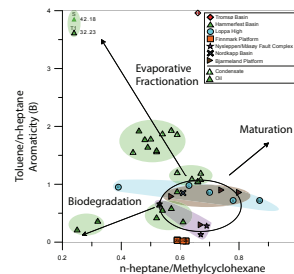


**Figure 3:** Oil Transformation Star Diagrams representing different alteration mechanisms in the LHC fraction. Low Tr1 values characterize water-washing and/or long-distance migration of the LHC due to the loss of the water soluble compound toluene, whereas high Tr1 values illustrate locally arrived LHC. Decreasing values for the Tr2-Tr5 and Tr7-Tr8 parameters indicate biodegradation. The Tromsø Basin sample is the most unaltered sample in the database (note the different Tr1 scale). Locally derived and long-distance migrated HC are found in the Hammerfest Basin. All other samples represent migrated LHC fractions based on their reduced toluene content. The very low Tr1 values for the Finnmark Platform might be a source rock effect. High Tr2-Tr8 values for one Loppa High sample indicate a fresh gas-gas.

## Results & Discussion - II

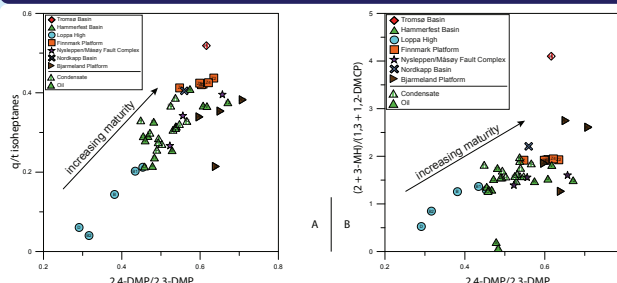


**Figure 4:** Diagram showing different maturity levels and biodegradation of the samples. Two samples from the Hammerfest Basin (Goliat) are biodegraded. Lowest maturity is found in the samples from the Loppa High. Samples from the Finnmark Platform, the Nordkapp Basin, the Bjarmeland Platform and the Tromsø Basin show highest maturity.



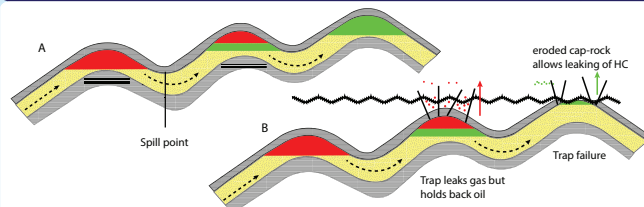
**Figure 5:** Cross-plot illustrating several condensate and oil samples from the Hammerfest Basin as fractionated. High aromaticity values for condensates reveal several gas-stripping events. Fractionated oils were found under gas-caps indicating the traps were able to hold back both phases and that it is big enough not to spill oil. Samples indicating biodegradation correlate well with Fig. 3 and Fig. 4.

## Results & Discussion - III



**Figure 6:** Two crossplots (A) and (B) modified after Chung et al., (2004) illustrating different maturities in the study area. The Loppa High samples show the lowest maturity. Samples from the Hammerfest Basin and the Måsøy/Nysleppen Fault Complex plot with medium maturities, whereas samples from the Nordkapp Basin, the Bjarmeland Platform, the Finnmark Platform and the Tromsø Basin are characterized by highest maturities. These results correlate very well with observations made in Fig. 4.

## Results & Discussion - IV



**Figure 7:** Two models illustrating the difference between a tight and a brittle cap-rock. A) Tight cap-rock model - 1: Gas expansion due to uplift. The oil remigrates up into the 2nd trap. 2: The oil separates into a gaseous and liquid phase whereas the gas expands again and pushes the oil upward into the 3rd trap. The cap-rock has the ability to hold back both oil and gas. B) Brittle cap-rock model - 1: Gas expansion due to uplift and the oil phase migrates up into the 2nd trap. 2: Uplift induced brittle cap-rock leaks gas but holds back oil. 3: Syn-uplift remigrated oil leaks out of the trap due to uplift induced erosion of the cap-rock.

## Conclusions

- 1) High toluene and benzene contents reveal oil and condensate samples from the Tromsø Basin and Hammerfest Basin as **locally derived**, whereas **long-distance migration** has affected the LHC in most other oil samples. Low toluene and benzene content in the biodegraded samples might be a result of combination of water-washing and long-distance migration.
- 2) **Evaporative fractionation** occurs only in the Hammerfest Basin. Most of the fractionated samples are condensates with high aromaticity values which points towards repeated gas-stripping episodes. Fractionated oil samples lie under gas-caps with tight cap-rocks. Some oils show a waxy n-alkane signature that points towards palaeo oil generation. Traps that are not filled to spill-point might explain the occurrence of these waxy oils beneath the condensates.
- 3) **LHC biodegradation** is limited to oils on the proximal basin margins in the Hammerfest Basin which might be related to the occurrence of fragile cap-rocks and traps allowing water to intrude
- 4) **Highest maturity** is recorded for oil samples on the Finnmark Platform, the Bjarmeland Platform and the Tromsø Basin condensate while oils from the Loppa High show **low maturities**.

## References

- Chung, H. M., C. C. Walters, S. Buck, and G. Bingham, 1998. Mixed signals of the source and thermal maturity for petroleum accumulations from light hydrocarbons: an example of the Beryl field. *Organic Geochemistry*, v. 29, no. 1, p. 381-396.
- Gussow, W. C., 1954. Differential entrapment of oil and gas: a fundamental principle. *AAPG Bulletin*, v. 38, no. 5, p. 816-853.
- Halpern, H. J., 1995. Development and applications of light hydrocarbon based star diagrams. *AAPG Bulletin*, 79 (6), 801-815.
- Karlsen, D. A., and Skeie, J. E., 2006. Petroleum Migration, Faults and Overpressure, Part I: Calibrating Basin Modelling using Petroleum in Traps - a Review. *Journal of Petroleum Geology*, 29 (3), 227-256.
- Ohm, S. E., Karlsen, D. A., and Austin, T. J. F., 2008. Geochemically driven exploration models in uplifted areas: Examples from the Norwegian Barents Sea. *AAPG Bulletin*, 92 (9), 1191-1223.
- Silverman, S. R., 1965. Migration and Segregation of Oil and Gas. In A. Young and J. E. Gally, eds. *Fluids in Subsurface Environments*. AAPG Memoir, v. 4, p. 53-65.
- Thompson, K. F. M., 1987. Fractionated aromatic petroleum and the generation of gas-condensates. *Organic Geochemistry*, 11 (6), 573-590.

## Acknowledgements

This study is part of a PhD project and represents a unified effort under the umbrella of the Barents Sea Consortium at the University of Oslo, financed by **NORECO**, **Lundin**, and **RWE-Dea** with partnership also to **Wintershall** and **ConocoPhillips** and affiliations to **UNIS** at Svalbard and **NPD** Norway. The authors would like to thank Noreco for allowing to publish the data.



## Poster 3

Lerch, B., Karlsen, D.A. and Duggan, D. 2015. Geochemical Characterization of Loppa High oils (SW-Barents Sea) and implications for regional petroleum systems. 27th IMOG Conference, 13.09. – 18.09.2015, Prague, Czech Republic.



# Geochemical characterization of Loppa High oils (SW-Barents Sea) and implications for regional petroleum systems

Benedikt Lerch<sup>\*1</sup>, Dag Arild Karlsen<sup>1</sup> and Deirdre Duggan<sup>2</sup>

<sup>\*</sup>benedikt.lerch@geo.uio.no, <sup>1</sup>Departement of Geosciences, University of Oslo, <sup>2</sup>Noreco, Stavanger

Poster D0125



## Objective

Possible generation from numerous source rocks and repeated uplift and burial events (Ohm et al., 2008) may have resulted in mixing and remigration of petroleum in the SW-Barents Sea (Lerch et al., 2015, 2016). To reveal geochemical variations in oils from the Loppa High, a systematic oil-oil correlation using three petroleum compound classes was used to investigate molecular evidence for the presence of mixed and altered oils. Beyond this, the ages of the inferred source rocks of the oils are of greatest interest. Samples in this study were taken from a greater dataset that include stable carbon isotopes and age specific biomarkers. However, some of the oils in the study are lacking these data. In order to overcome this circumstance, we tried to find additional characteristics that could be used as unconventional age indicators. Finally, we tried to draw inference about petroleum distributions based on the observed results.

## Study area & samples

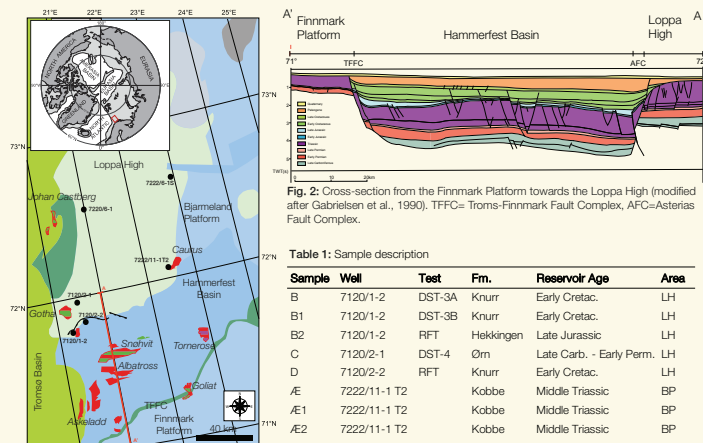


Fig. 1: Study area. Well locations are indicated by black dots and well names. Cross-section A-A' is shown in Fig. 2. TFFC=Troms-Finnmark Fault Complex

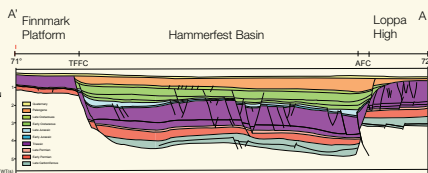


Fig. 2: Cross-section from the Finnmark Platform towards the Loppa High (modified after Gabrielsen et al., 1990). TFFC=Troms-Finnmark Fault Complex, AFC=Asterias Fault Complex.

Table 1: Sample description

Sample	Well	Test	Fm.	Reservoir Age	Area
B	7120/1-2	DST-3A	Knurr	Early Cretac.	LH
B1	7120/1-2	DST-3B	Knurr	Early Cretac.	LH
B2	7120/1-2	RFT	Hekkingen	Late Jurassic	LH
C	7120/2-1	DST-4	Øm	Late Carb. - Early Perm.	LH
D	7120/2-2	RFT	Knurr	Early Cretac.	LH
Æ	7222/11-1 T2		Kobbe	Middle Triassic	BP
Æ1	7222/11-1 T2		Kobbe	Middle Triassic	BP
Æ2	7222/11-1 T2		Kobbe	Middle Triassic	BP
Ø	7222/6-1 S	MDT	Snadd	Middle Triassic	BP
Å	7220/6-1	MDT	Øm	Late Carb. - Early Perm.	LH

LH= Loppa High; BP= Bjarmeland Platform

## Thermal maturity parameters

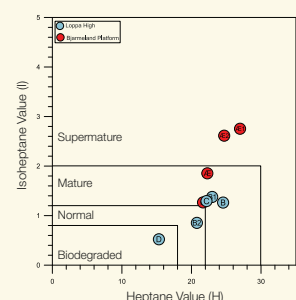


Fig. 3: Light hydrocarbon (LHC) maturity parameters differentiating samples from the Loppa High and the Bjarmeland Platform. Samples Æ-E22 from the Bjarmeland Platform indicate much higher generation temperatures than samples from the Loppa High. Samples C and D indicate lower generation temperatures than in the medium and biomarker range fractions (Figs. 4, 5 and 6).

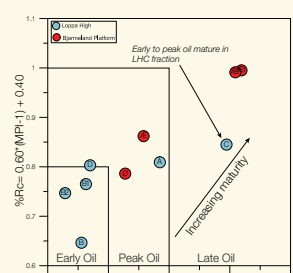


Fig. 4: Cross-plot of calculated vitrinite reflectivities indicating thermal maturity. Sample C shows a higher maturity compared to the LHC compound fraction (Fig. 3) that indicates mixing. Samples Æ-E22 show the same maturity trend as for the light hydrocarbons (Fig. 3) suggesting generation from a single source rock.

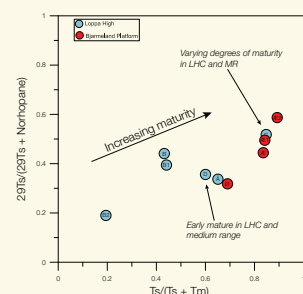


Fig. 5: Cross-plot indicating thermal maturity based on saturated compounds. Sample C indicates peak to late oil window generation. Sample D shows higher generation temperatures for the biomarker range than for the LHC and medium range fractions (Figs. 3 and 4), indicating mixing, while sample B2 plots as early mature as shown in Figs. 3 and 4.

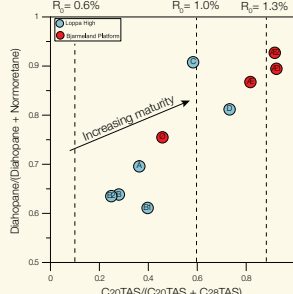


Fig. 6: Cross-plot of saturated vs. triaromatic compounds. Peak oil maturity is indicated for sample D that showed lower maturities in Figs. 3 and 4. The overall high maturities for samples Æ-E22 indicate generation from a single source rock as shown in Figs. 3, 4 and 5.

## References

- Gabrielsen, R.H., Flæmseth, R.B., Jensen, L.N., Kvalheim, J.E., Ris, F., 1990. Structural Elements of the Norwegian Continental Shelf Pt. 1. The Barents Sea Region. Norwegian Petroleum Directorate Bulletin 6.
- Halpern, H.J., 1995. Development and applications of light hydrocarbon based star diagrams. American Association of Petroleum Geologists Bulletin 79, 801-815.
- Karlsen, D.A., Skeie, J.E., 2006. Petroleum Migration, Faults and Overpressure, Part I: Calibrating Basin Modeling using Petroleum in Traps - a Review. Journal of Petroleum Geology 29, 227-256.
- Lerch, B., Karlsen, D.A., Metlapour, Z., Seland, R., Backer-Ove, K., 2015. (submitted). Organic Geochemistry of Barents Sea Petroleum: Thermal maturity and alteration and mixing processes in oils and condensates. Journal of Petroleum Geology.
- Lerch, B., Karlsen, D.A., Abay, T., Duggan, D., Seland, R., Backer-Ove, K., 2016 (accepted). Regional oil petroleum alteration trends in Barents Sea oils and condensates as a result of migration regimes and processes. American Association of Petroleum Geologists Bulletin.
- Ohm, S.E., Karlsen, D.A., Austin, T.J.F., 2008. Geochemically driven exploration models in uplifted areas: Examples from the Norwegian Barents Sea. American Association of Petroleum Geologists Bulletin 92, 1191-1223.

## Acknowledgments

This study is part of The Common Ground – Arctic Petroleum System Research\* project at the University of Oslo, with close cooperation to UNIS, Noreco, Lundin, Dea, Wintershall and ConocoPhillips. The authors would like to thank NORECO ASA for project funding and cooperation.

## Conclusions

- » Variations in thermal maturity parameters and various biodegradation signatures among the three hydrocarbon compound classes (LHC, Fig. 3, medium range, Fig. 4, and biomarker range, Figs. 5, 6) revealed mixing in some samples. It is suggested that the C20+ fraction represents a possible black-oil-related signature, while the C20- fraction indicates a later charge. The unaltered, early mature light hydrocarbon signature in sample B2 (Figs. 8 and 9) suggests recent migration, and thus a live petroleum system in the area.
- » A characteristic "triplet-terpane-pattern" can be used for differentiation between inferred Permian/Triassic and Jurassic sourced oils in case stable isotope data and age specific parameters are lacking.
- » Oils on the southern rim of the Loppa High show a strong Jurassic signature, while oils on the Loppa High and the Bjarmeland Platform show inferred Permian/Triassic signatures (Fig. 12). Long-distance migration from the Hammerfest Basin is suggested for the oils on the southern rim of the Loppa High (Figs. 12, 13).
- » Distribution of oils in the region suggests more Permian/Triassic petroleum to be found on the Loppa High. It is proposed that reservoirs on the Loppa High and the Bjarmeland Platform hosting inferred Permian/Triassic oils were "shielded" from Jurassic charges. The distance from the main pod of Jurassic source rocks could have enhanced the possibility for preservation of inferred Permian/Triassic signatures.

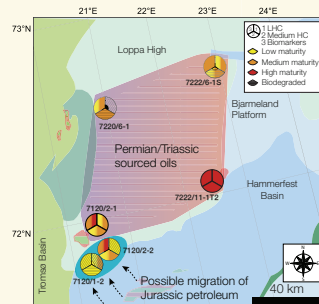


Fig. 12: Map showing the distribution of inferred Permian/Triassic and Jurassic sourced oils. The cake diagrams represent the maturity signatures related to the three investigated compound classes. The dashed overlay indicates biodegradation in the respective hydrocarbon fraction.

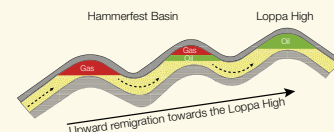


Fig. 13: Fill-spill type model showing migration from the Hammerfest Basin towards the Loppa High (cf. Fig. 2). Uplift-induced gas expansion in the Hammerfest Basin pushed the oil below spill point and initiated an upward remigration leading to petroleum mixtures on the southern rim of the Loppa High. This model is based on the occurrence of residual oil columns and condensates in the SW Hammerfest Basin (Fig. 1), and reduced toluene concentrations as indicated by the diminished Tr1 ratios in Fig. 9.

## Alteration and mixing signatures

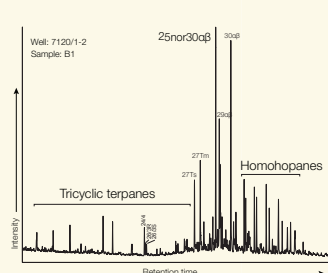


Fig. 7: Representative GC-MS mass chromatogram (m/z = 191) of an inferred Jurassic oil showing a severe biodegraded paleo-oil (high 25nor30d peak) that was overprinted by a later influx of a non-altered, early mature charge, hence indicating a petroleum mixture. The same pattern was also observed for sample B.

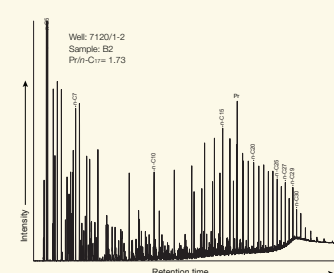


Fig. 8: Whole-oil GC-FID chromatogram of sample B2 (outer blue line in Fig. 9) characterized by elevated Pr1/C1 values suggesting incipient biodegradation. Greater concentrations of light hydrocarbon compounds C2-C6 compared to C7-C10 represent a more recent, unaltered LHC charge, thus indicating mixing of two petroleum charges.

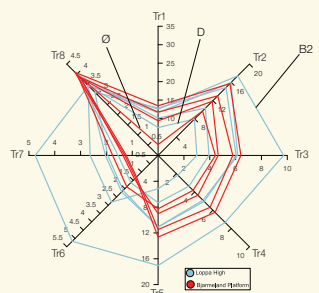


Fig. 9: C7-oil transformation star diagram (Halpern, 1995) distinguishing the oils in respect of alteration signatures. Low Tr1 values (toluene/1,1DMC/C2) indicate water-washing / long distance migration. It is thought that water soluble aromatic compounds get "stripped off" during migration (cf. Karlsen and Skeie, 2006; Lerch et al., 2016). The pattern for sample B2 indicates a recent, unaltered LHC charge (see Fig. 8). Slight biodegradation based on lower Tr2-Tr8 ratios however is indicated for sample D, which is in accordance with Fig. 3. Based on C7-oil correlation star diagrams, it was found that the LHC for samples B2 and D have been generated from a genetically linked source rock. Thus, it can be suggested that the LHC in sample D experienced post-emplacement alteration.

## Terpane compounds as unconventional age indicators?

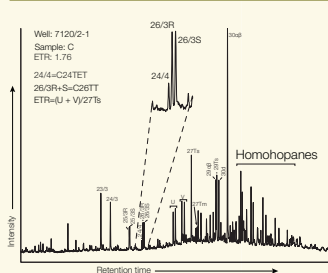


Fig. 10: Representative GC-MS mass chromatogram (m/z = 191) showing a characteristic "triplet-terpane pattern" with elevated CaTT over CuTT. This pattern was observed in a greater dataset that suggests Permian/Triassic origin (based on  $\delta^{13}C$  values, ETR ratios and C<sub>24</sub>/C<sub>28</sub> steranes). Jurassic derived samples show elevated CuTT over CaTT (cf. Fig. 7).

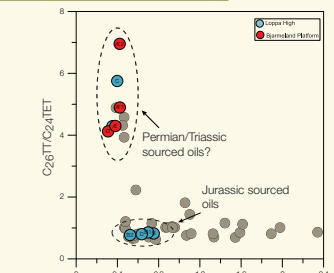


Fig. 11: Cross-plot of terpane compounds differentiating petroleum sourced from inferred Permian/Triassic and Jurassic sources. Samples from the same dataset (grey dots) are shown in addition to support the use of these compounds in the present study.



## Poster 4

Lerch, B., Karlsen, D.A., Seland, R. and Backer-Owe, K. 2016. Ages and Depositional Environments of Barents Sea Petroleum. AAPG and SEG, International Conference and Exhibition, 03.04. – 06.04.2016, Barcelona, Spain.



# Ages and Depositional Environments of Barents Sea Petroleum

Benedikt Lerch\*<sup>1</sup> and Dag Arild Karlsen<sup>1</sup>

\*benedikt.lerch@geo.uio.no, <sup>1</sup>Department of Geosciences, University of Oslo,

AAPG SEG  
International Conference  
& Exhibition 2016  
3-6 April • Barcelona, Spain

## Objective

The Norwegian Barents Sea comprises a multiple source rock basin that has been affected by several uplift related, erosional and glacial processes that influenced the petroleum systems (Ohm et al., 2008). Previous studies on Barents Sea petroleum systems showed that many petroleum systems in the present database are characterized as "petroleum blends" (Lerch et al., 2016a, b). Based on thermal maturity variations among the different hydrocarbon compound classes and manifold alteration signatures, it has been found that two characteristic petroleum signatures exist: 1) a C<sub>20+</sub> "paleo-oil" signature, and 2) a C<sub>20+</sub> fraction that is considered to represent a more recent charge. The objective of this study is to delineate the inferred source rocks in terms of age, depositional environment and organic matter input of the C<sub>20+</sub> "paleo-oil" fraction.

## Study area

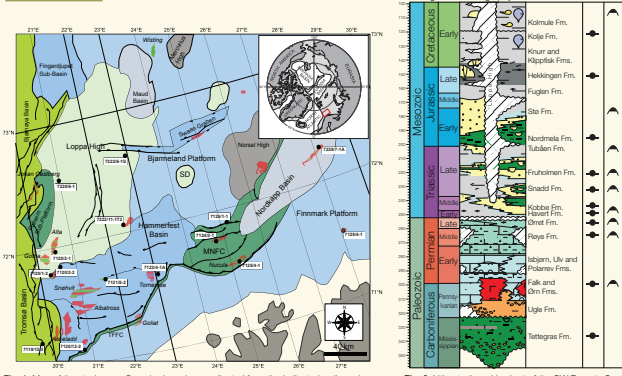


Fig. 1: Map of the study area. Samples have been collected from the indicated wells and the discoveries Aekelad, Albatross, Snohvit, Torshov and Gollat. TFCC = Troms-Finnmark Fault Complex; MNFC = Måsøy-Nysleppen Fault Complex.

Fig. 2: Lithostratigraphic chart of the SW Barents Sea.

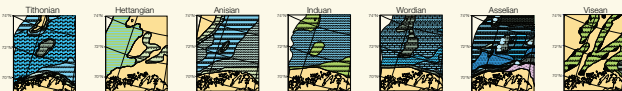


Fig. 3: Paleogeographical maps showing the different depositional settings in the study area between 70° and 74°N and 20° and 30°E (modified after Smolir et al., 2009).

## Conclusions

- Four petroleum families have been identified based on biomarker characteristics and multivariate statistical analysis. The classification has been established on C<sub>20+</sub> compounds and thus does not reveal the origin of the C<sub>20+</sub> contribution. The petroleum families are: Family A: petroleum generated from inferred Carboniferous source rocks; Family B: petroleum generated from inferred Permian/Triassic source rocks; Family C: petroleum generated from inferred Jurassic source rocks; and Family D: condensates from inferred Triassic/Jurassic source rocks.
- Biomarker analyses revealed a transitional depositional environment for the majority of the samples. The redox conditions varied from slightly anoxic to dysoxic-oxic and suggest input of marine to terrestrial derived organic matter, with kerogen ranging from possible Type I, to mainly Type II to Type III/III to III/II.
- The results indicate that most petroleum families and affinities to source rocks are largely predictable from basin position and type (Fig. 14).
- Carboniferous petroleum seems to represent an important contribution in the graben systems of the Finnmark Platform. It is suggested that Permian/Triassic petroleum are found on platform highs and structurally more complex regions that are located far away from Jurassic hydrocarbon migration paths, as well as in the eastern part of the study area. Pre-Jurassic signatures in the Hammerfest Basin may have been diluted by later arrived Jurassic charges, and may illustrate the different facies signatures for the Jurassic oils. It has been found that, in general, the majority of the samples seem to be a "blend".

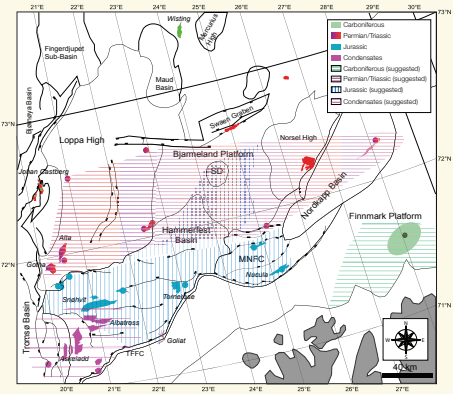


Fig. 14: Map of the study area showing the distribution of petroleum families related to their ages. The wells are colored in the respective color of the age of the petroleum, while the dashed lines represent an interpretation of the dominant petroleum age.

Follow the author on Twitter  
@benediktlerch

## Organic Geochemistry I - Stable Isotopes and Biomarkers Indicating the Age

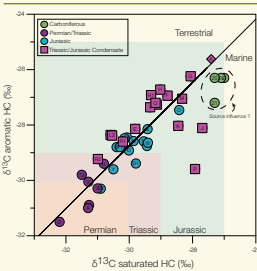


Fig. 4: Cross-plot of  $\delta^{13}\text{C}_{\text{aromatic HC}}$  versus  $\delta^{13}\text{C}_{\text{saturated HC}}$  indicating the inferred ages of the petroleum. The age classification was done according to Ohm et al. (2008). Note that the condensates demonstrate a more terrigenous origin compared to the oils.

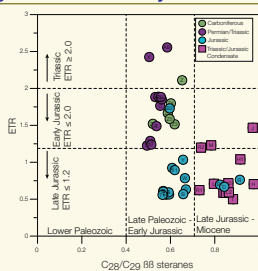


Fig. 5: The inferred ages of the petroleum are shown based on the ratios C<sub>29</sub>/C<sub>27</sub> 8S steranes and the extended triptyc terpane ratio (ETR). The elevated C<sub>29</sub>/C<sub>27</sub> 8S sterane ratio for the condensates is related to fractionation processes.

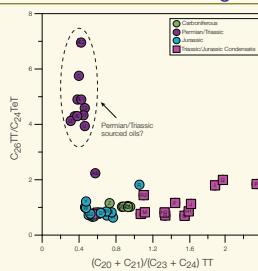


Fig. 6: The ratios applied are used to discriminate between Jurassic and Permian/Triassic sourced petroleum. The inferred Permian/Triassic sourced petroleum are characterized by sparse C<sub>24</sub>/Tet and more abundant C<sub>26</sub>/Tet.

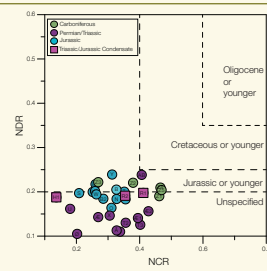


Fig. 7: The cross-plot of the norcholesterane (NCR) versus the norcholesterane (NCR) ratio excludes a contribution of Cretaceous generated petroleum. Yet, the elevated ratios of sample AB probably indicate a migration effect as both Cretaceous and Jurassic source rocks are immature in the eastern study area.

## Organic Geochemistry II - Biomarkers Indicative of Depositional Environment and Organic Matter Input

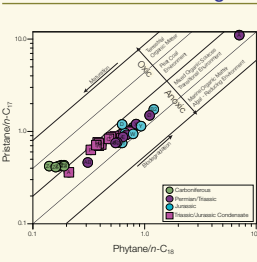


Fig. 8: Cross-plot of Phytane/n-C<sub>18</sub> versus Pristane/n-C<sub>17</sub> indicating the depositional environments of the inferred source rocks. Note that sample B2 and D show increased values that indicate incipient biodegradation. The majority of the samples implicate deposition under suboxic-dysoxic conditions in transitional environments.

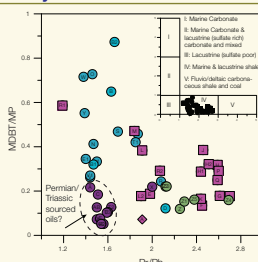


Fig. 9: Cross-plot of Pr/Ph versus MDT/MP demonstrating the depositional environments of the inferred source rocks. Few samples that are suggested to have been sourced from Jurassic source rocks show higher abundances of sulfur containing compounds that might implicate mixing. The Permian/Triassic sourced samples implicate similar depositional environments.

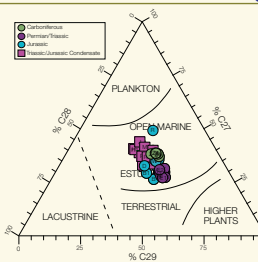


Fig. 10: Ternary diagram showing the relative percentage distribution of the 8S steranes (m/z 218) that indicate the depositional environments of the inferred source rocks. The majority of the samples suggest generation from source rocks deposited in mixed marine-terrestrial environments.

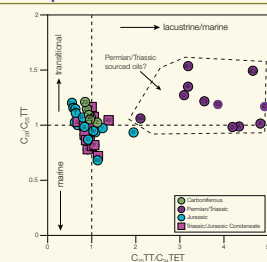


Fig. 11: Depositional environments indicated by the use of triptyc and tetraptyc terpane compounds. The inferred Permian/Triassic sourced petroleum indicate deposition under lacustrine-marine conditions.

## Classification of Petroleum Families

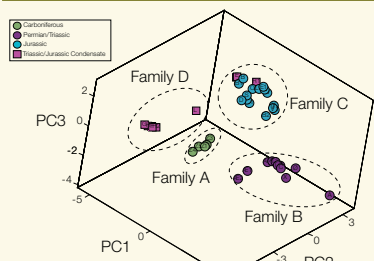
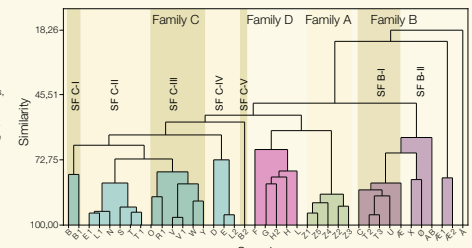


Fig. 12: 3D scatter-plot showing the results of the principal component analysis (PCA), where the first three components explain 67.9% of the total variance. The PCA was conducted for 39 samples based on 23 biomarker parameters (not all are shown in the present paper). It was possible to define four petroleum families that correlate very well with the results obtained from the geochemical analysis: Family A: inferred Carboniferous sourced petroleum; Family B: inferred Permian/Triassic sourced petroleum; Family C: inferred Jurassic sourced petroleum; Family D: inferred Triassic and Jurassic condensates. Samples that are characterized by low abundances of certain biomarkers have been excluded from the PCA to obtain a meaningful matrix. Yet, slightly altered and highly mature samples have been included as no influence of alteration signatures has been observed in prior versions of the PCA.

Fig. 13: Dendrogram for 39 samples based on 23 biomarkers. The dendrogram was carried out using standardized values, average linkage and Euclidean distance using the Minitab17 software.

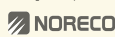


## References

This study is part of "The Common Ground - Arctic Petroleum System Research" project at the University of Oslo, with close cooperation to UNIS, Noreco, Lundin, Dea, Wintershall and ConocoPhillips. The authors would like to thank Noreco ASA for project funding and cooperation.



UO Department of Geosciences  
University of Oslo



Lerch, B., D. A. Karlsen, T. B. Abay, D. Dugger, R. Seland, and K. Backer-Owe, 2016a, Regional petroleum alteration trends in Barents Sea oils and condensates as a clue to migration regimes and processes. AAPG Bulletin, v. 100, no. 2, p. 189-193.  
Lerch, B., D. A. Karlsen, C. Møller, R. Seland, and K. Backer-Owe, 2016b, Organic Geochemistry of Barents Sea petroleum: Thermal maturity and alteration and mixing processes in oils and condensates. Journal of Petroleum Geology, v. 39, no. 2, p. 125-147.  
Ohm, S.E., D. A. Karlsen, and T.J. Austin, 2008, Geotectonically driven migration models in uplifted areas: Examples from the Norwegian Barents Sea. AAPG Bulletin, v. 92, no. 9, p. 1191-1223.  
Smolir, M., O. Petrov, G. B. Larsen, and S. Werner, 2009, Atlas. Geological History of the Barents Sea. Geological Survey of Norway, Trondheim, 134pp.

