



NORWEGIAN PETROLEUM
DIRECTORATE

npd.no

PETROLEUM RESOURCES ON THE NORWEGIAN CONTINENTAL SHELF 2013 EXPLORATION

PETROLEUM RESOURCES ON THE
NORWEGIAN CONTINENTAL SHELF

2013

EXPLORATION

Published by the
Norwegian Petroleum Directorate
Professor Olav Hanssens vei 10
P O Box 600
NO-4003 Stavanger
Telephone: +47 51 87 60 00
Telefax: +47 51 55 15 71
E-mail: postboks@npd.no
Internet: www.npd.no

English translation: Rolf E Gooderham
Design/layout: Janne-Beth Carlsen N'Jai
Illustrations: Rune Goa
Photos: Arne Bjørøen
Printed by: Kai Hansen, Stavanger
Paper: Silk 200/130 g

ISBN 978-82-7257-103-9

Preface

Two years have passed since the NPD last issued a resource report. The biggest change in the petroleum industry since then is that optimism on the Norwegian continental shelf (NCS) is greater than it has been for a long time.

After the government adjusted its exploration policy about 10 years ago, which included opening up for new companies on the NCS, the number of participants has almost doubled and the player picture has become more diversified. This has contributed to a high and stable level of exploration activity, and many new discoveries have been made. The number of applications and awards in the various licensing rounds shows that the NCS remains an attractive petroleum province.

This resource report presents analyses which show that what the NPD calls medium-sized companies are strengthening their position on the NCS. Such enterprises appear to be taking over the position held by the integrated international oil companies on the NCS since offshore activities began there almost 50 years ago.

It might reasonably be supposed that the substantial discoveries of recent years have reduced the estimate of undiscovered resources. But that is not the case. Expected undiscovered resources are actually larger than they were two years ago. This is primarily because new knowledge encourages greater confidence in opportunities for further discoveries. A lot of oil and gas remains to be found in all three parts of the NCS – the North, Norwegian and Barents Seas.

The North Sea has perhaps provided the biggest surprises in recent years, with substantial discoveries in areas originally awarded as far back as the first licensing round in 1965. In the Barents Sea, new discoveries have contributed to increased understanding of its geology, while exploration activity in the frontier areas of the Norwegian Sea has not lived up to the NPD's expectations – yet.

An expansion occurred to the NCS two years ago, when Norway and Russia signed the final treaty on maritime delimitation in the Barents Sea. The NPD has recently mapped the Barents Sea South-East area, which could be opened to the industry as early as 2013 if the Storting (parliament) gives its consent.

The NPD is also mapping Norway's continental shelf around Jan Mayen, with the work due to be completed in 2014. In addition to providing knowledge of potential petroleum resources, this mapping could contribute to increased knowledge of the geology in the deepwater areas west of the Norwegian Sea.

The NPD's job is to help create the largest possible value for Norwegian society from the oil and gas industry through an



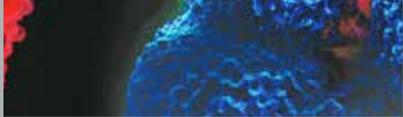
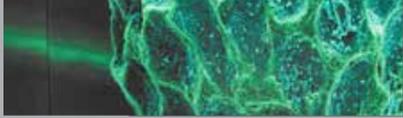
Photo: Emile Ashley

acceptable management of resources rooted in safety, emergency preparedness and protection of the natural environment.

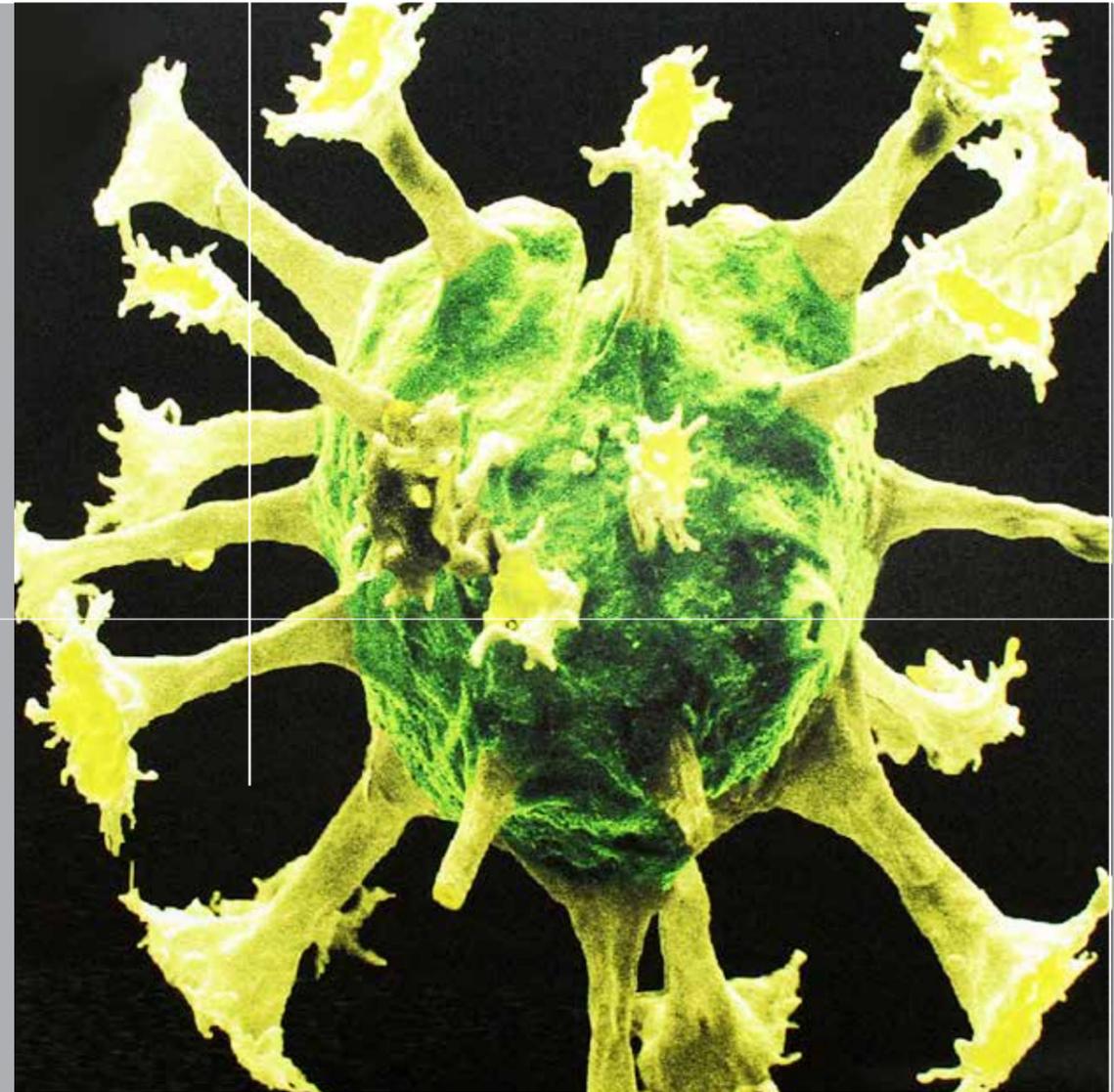
Maintaining an overview of and assessing petroleum operations and resources on the NCS by the NPD is therefore very important. That forms an important foundation for a knowledge-based, long-term and predictable management of the oil and gas resources which belong to the people of Norway.

Sissel H Eriksen
Exploration director
Norwegian Petroleum Directorate

Contents

		Preface	3
	1	Introduction and summary	7-10
	2	Exploration activity and results	11-17
	3	The players	19-23
	4	Undiscovered resources	25-29
	5	Exploration history and resource growth	31-36
	6	Barents Sea South-East	37-45
	7	Jan Mayen	47-59

Introduction and summary



1

Half a century has passed this year since Norway extended its sovereignty over the NCS and the government gave, on a general basis, interested parties permission to conduct geophysical surveys there.

Seismic data acquisition on the NCS then got going in earnest, with a gradual start to this work in early 1963. The very first exploration well was spudded three years later. That proved to be dry, but a strike was made as early as the second wildcat without it being considered commercially interesting at the time. This was the discovery well for the Balder oil field, which came on stream in 1999.

It took 27 wildcats on the NCS before the first commercial discovery – Ekofisk – was announced in December 1969. When its size became known, exploring the NCS became very attractive for the oil companies and a number of big discoveries were made over the next 15 years. The bulk of the resources found on the NCS were proven in this period. See figure 1.1, which presents the growth in proven resources from drilling wildcats.

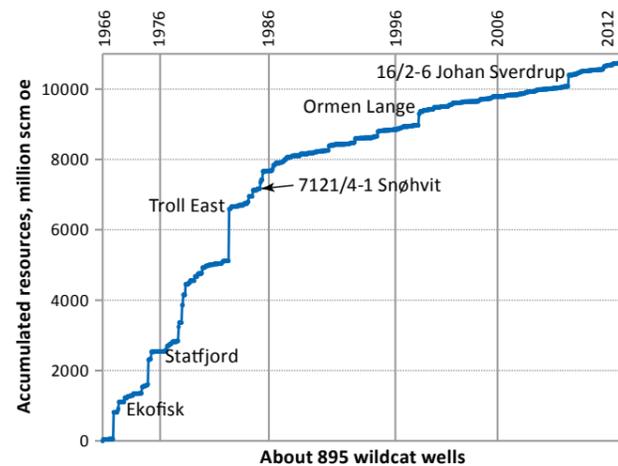


Figure 1.1 Resource growth on the NCS, 1966-2012.

The big discoveries were further apart after 1986, even though exploration activity was generally high. Interest in exploring the NCS declined markedly from 1997, and only 12 exploration wells were spudded in 2005.

Rising oil prices and exploration policy changes helped to reverse this trend, and several substantial discoveries have been made in recent years, such as 16/2-6 Johan Sverdrup in the North Sea and Johan Castberg (7220/8-1 Skrugard and 7220/7-1 Havis) in the Barents Sea. Considerable knowledge of mature areas, combined with diversity and new solutions plus a willingness to accept risk, have yielded good results. Exploration optimism has therefore been high over the past couple of years.

Although increased knowledge and greater diversity could yield further discoveries in mature areas, substantially more or larger finds are needed if production on the NCS is to be maintained at a high level – which is an important political goal in White Paper 28 (2010-2011), the most recent policy document on the petroleum sector. This underlines the long-term nature of the industry and – in addition to a high level of exploration activity – gives emphasis

to the need to concentrate more strongly on producing fields, to bring discoveries on stream and to make provision for opening new areas.

The NPD believes that substantial resources remain to be found. Combined with resources in discoveries and improved recovery from producing fields, these could lay the basis for profitable production from the NCS for a long time beyond 2030 – as shown in figure 1.2. How long production can be maintained depends on several factors, including resources, technological advances, cost developments, the player picture, political operating parameters and the price of oil and gas in relation to other energy carriers.

Active exploration is essential if undiscovered resources are to contribute to production and create value both for the industry and for society. Through its exploration policy, the government has provided the companies with a great deal of exploration acreage in both mature and frontier areas. This has so far yielded good results. Exploration activity on the NCS has been high, particularly over the past five years, and several major discoveries have been made. Chapter 2 presents the development and results of exploration activity, with the emphasis on trends over the past 15 years.

A diversity of participants is important in achieving the highest possible value creation for society from the petroleum industry. The number of players has increased substantially since 2000, when the government introduced policy changes at a time of low exploration activity. Chapter 3 presents the contribution of the players over the past 15 years. The analyses show that the player picture has become more diversified and that all company categories have contributed positively to both exploration activity and results. Along with large Norwegian companies, medium-sized companies have been responsible for the biggest investment in exploration over the past 15 years. This growth is one reason why the medium-sized companies appear to be taking over the position held by the integrated international oil companies on the NCS since activities began there almost 50 years ago.

Chapter 4 presents an updated estimated of total undiscovered resources on the NCS at 31 December 2012. See the box on the resource account. In addition comes a resource estimate for Barents Sea South-East and the offshore area around Jan Mayen.

Much oil and gas remains to be discovered on the NCS. Considerable knowledge of the geology is essential if the authorities are to

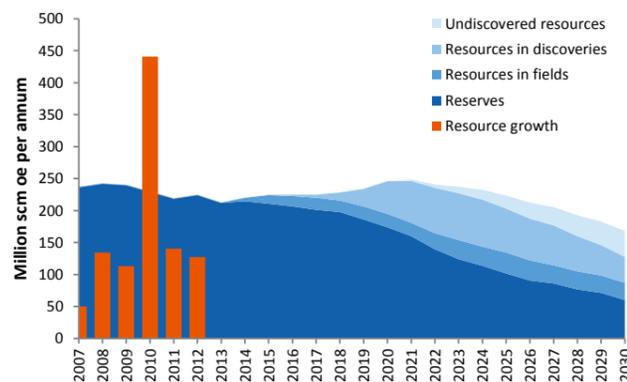
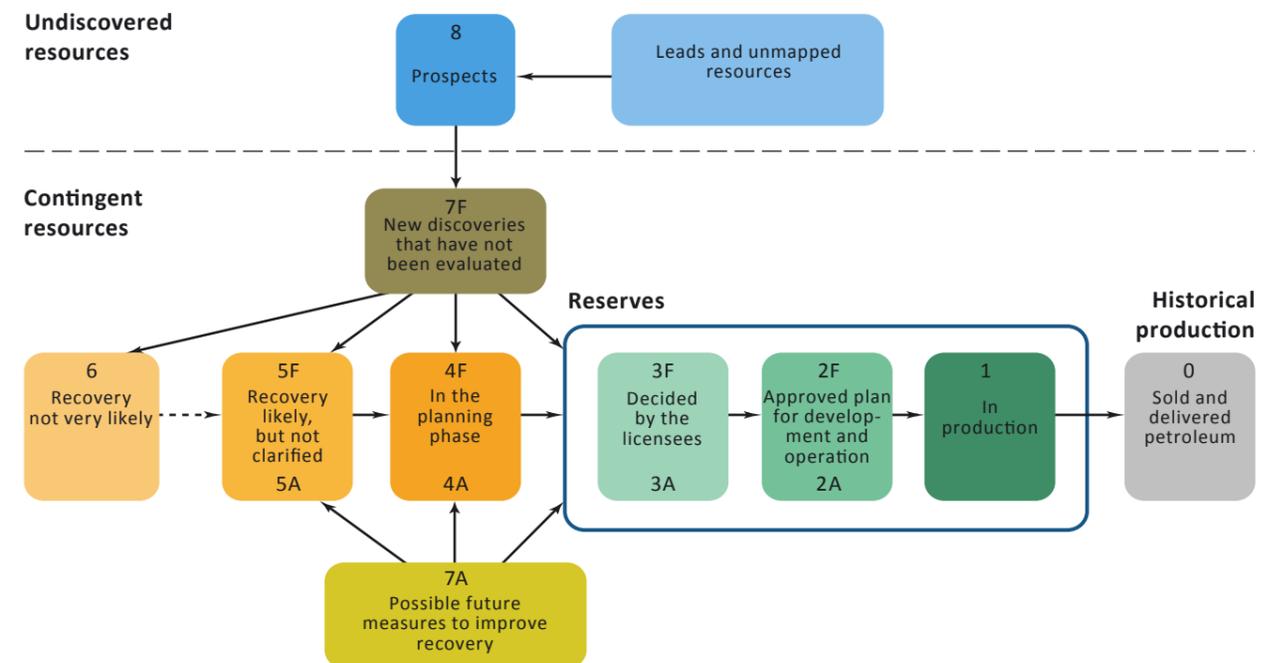


Figure 1.2 Resource growth on the NCS, historical and expected, 2007-30.

be able to play a key role in resource management. A good factual foundation and knowledge of geology help to reduce exploration risk and costs on the NCS. Even though major discoveries have been made in recent years, the estimate of undiscovered resources has risen because new knowledge gives greater confidence in the opportunities of finding more.

Chapter 5 describes the estimate for undiscovered reserves in a geographic area and for selected plays in connection with the exploration history of the area or play. Relationships are established in the form of a rising curve which shows how the area or play has been explored. A steep curve means that exploration activity has been a success in that considerable resources have been proven with few wildcats, while a shallow curve means that exploration activity has been more challenging and has yielded limited resources with many wildcats. Viewed in relation to the estimate for undiscovered resources, these curves can illustrate the remaining potential in the various plays and offshore areas.

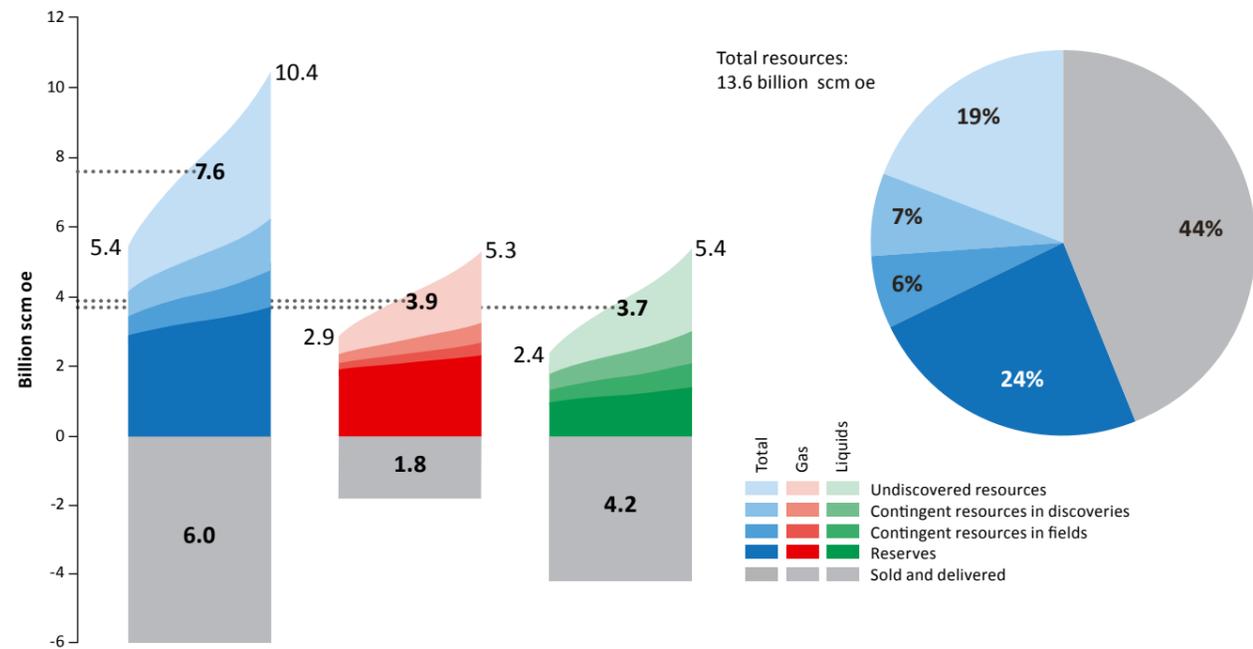
The final part of the report describes the geology of and provides a resource evaluation for the unopened areas in Barents Sea South-East (chapter 6) and around Jan Mayen (chapter 7). Substantial efforts have been devoted by the NPD in recent years to geological mapping and interpretation of these offshore areas. Mapping of Barents Sea South-East forms part of the factual base in the process of opening for petroleum activities. In the NPD's assessment, this is an area with structures which could contain substantial petroleum resources. Expected recoverable resources are estimated to be about 300 million standard cubic metres of oil equivalent (scm oe), with an upside of about 565 million scm oe. An opening process has also been initiated in the Jan Mayen area. The NPD is due to submit an updated evaluation of resources around the island in the spring of 2014. The status of the work and a preliminary resource estimate are presented in this report. A preliminary estimate of expected recoverable resources amounts to some 90 million scm oe, with an upside of about 460 million scm oe.



Classification of resources

The resource classification covers all estimated petroleum resources, both discovered and undiscovered. Petroleum volumes are classified by their maturity.

Resources are divided into the principal classes of historical production, reserves, contingent resources and undiscovered resources. Reserves relate to remaining recoverable petroleum resources in deposits which the licensees have decided to develop. Contingent resources are discovered petroleum volumes still not covered by a development decision. Undiscovered resources are volumes considered to be recoverable but not yet proven by drilling. Whether the estimated resources actually exist is uncertain. The various main classes are divided into sub-categories depending on the maturity of the various projects.



Resource account

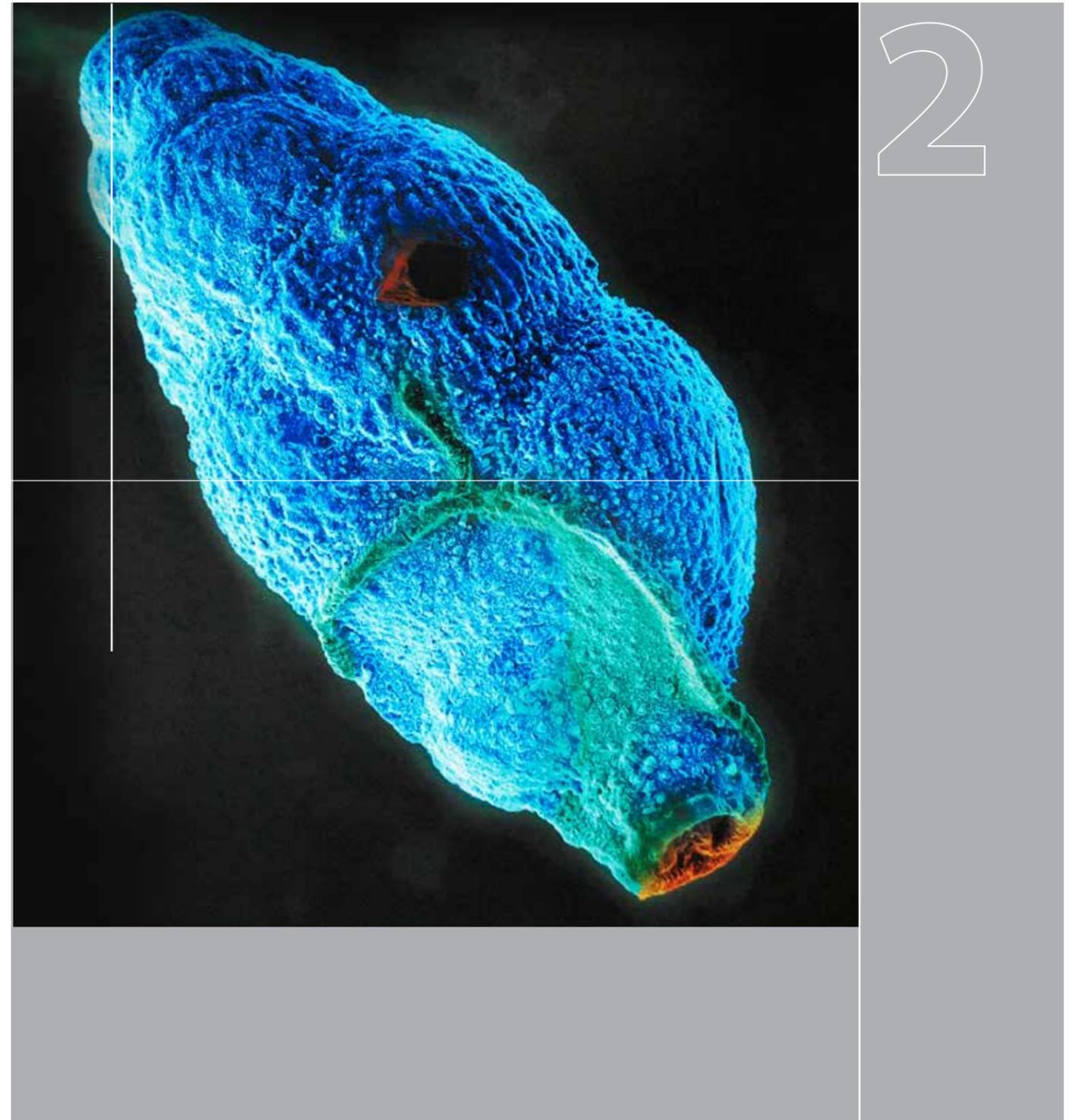
The NPD's resource account provides an overview of expected total recoverable petroleum resources, including those still to be discovered. The account at 31 December 2012, which was presented in the *Facts 2013* publication, covers all parts of the NCS with the exception of the continental shelf around Jan Mayen and Barents Sea East. Other areas not currently open for petroleum activities are included in the account.

Based on the NPD's resource classification, the account builds on data reported from the operator companies, the NPD's own assessments of fields and discoveries, and its estimate of undiscovered resources.

Six billion scm oe had been sold and delivered at 31 December 2012, or roughly 44 per cent of expected recoverable resources. Total recoverable resources are estimated to lie within an uncertainty range (P10 and P90) of 10.4-16.4 billion scm oe, with an expected value of 13.6 billion scm. See the figure.

The resource account at 31 December 2012 was drawn up before mapping of the continental shelf around Jan Mayen and the southern part of Barents Sea East (Barents Sea South-East) had been completed by the NPD. See chapters 6 and 7. Chapter 4 provides an updated estimate of undiscovered resources on the NCS, including resource estimates for the recently mapped areas. Barents Sea North-East has yet to be mapped, and is accordingly not included in the new resource estimate. The inclusion of resource estimates for Jan Mayen and Barents Sea South-East helped to increase undiscovered resources as a proportion of total recoverable resources (including petroleum produced and sold) from 19 to 21 per cent compared with the estimate at 31 December 2012.

Exploration activity and results



The level of exploration activity has been high over the past five years, with more than 40 exploration wells spudded per annum and extensive acquisition of seismic data. This development primarily reflects changes to Norwegian exploration policy at the start of the present century and the optimism generated by new discoveries and high oil prices. A marked increase in exploration activity has also been witnessed internationally in this period.

Many discoveries have resulted from the large number of wildcats. The most and biggest finds are being made in the North and Barents Seas.

Acreage

Norway's overall offshore area covers 2 040 000 square kilometres, almost 6.5 times greater than its mainland size. About half the area comprises sedimentary rocks which could contain petroleum. See figure 2.1.

With certain exceptions, the North and Norwegian Seas and the southern Barents Sea have been opened for petroleum activities. The opened areas cover 523 800 sq.km. Those which remain unopened are Barents Sea South-East and North, areas close to the coast in the Norwegian Sea, the area around Jan Mayen and most of the Skagerrak.

Environmental impact assessments are conducted pursuant to the Petroleum Activities Act before the Storting resolves to open new areas. As part of an opening process, the NPD acquires geological

and geophysical data on behalf of the government and produces an estimate of the resource potential of the area.

Opening processes have been initiated by the government for Barents Sea South-East and the offshore areas around Jan Mayen. See chapters 6 and 7. The question of opening Barents Sea South-East has been submitted to the Storting. Should it approve the proposal, this will be the first new area of the NCS to be opened to petroleum activities since 1994.

Oil companies primarily gain access to acreage by applying for production licences in numbered licensing rounds and in the awards in predefined areas (APA) scheme. In addition, the companies are able to buy and swap interests in production licences.

The whole North Sea was put on offer in the very first licensing round on the NCS, in 1965. This was the largest round to date in terms of area. The second largest numbered round was the 13th in 1991. See figure 2.2. This presents the acreage on offer and awarded in the numbered rounds, the North Sea awards (NSA – introduced in 1999 and the forerunner of the APA scheme) and the APA rounds.

Over the past 15 years, the amount of acreage put on offer has steadily increased. The number of licence awards and acreage awarded were at record levels in 2004-12, with an annual average of some 50 new licence awards (figure 2.3) and 23 000 sq.km in new licensed area (figure 2.2). The oil companies have displayed great interest in applying for acreage on offer, which shows that

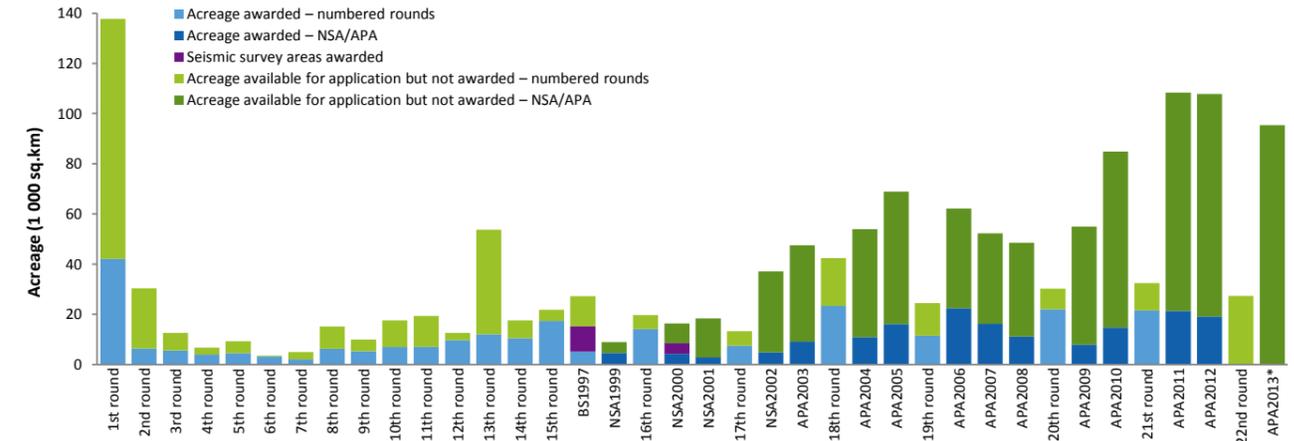


Figure 2.2. Acreage on offer and awarded on the NCS at 15 March 2013.

* At 15 March 2013

the NCS remains an attractive petroleum province. As more acreage becomes available, the amount which has been relinquished increases too. This must also be seen in relation to such government measures as changes to the area fee and the introduction of work programmes which put the industry under greater pressure than before to work actively with awarded acreage.

Recycling acreage – the Utsira High South example

Most of the acreage licensed under the APA scheme has been awarded and relinquished earlier. When new companies get the chance to explore relinquished acreage, it may turn out that they manage to mature substantial petroleum resources. A number of examples of this exist, with the exploration history of Utsira High South in a class of its own (see the fact box).

Exploration wells

From the start in 1966 until April 2013, almost 1 430 exploration wells have been drilled on the NCS. Such wells passed their first peak in the 1980s, at almost 50 per annum. See figure 2.4. During the 1990s, the annual count varied from 20 to nearly 50. A fairly steady decline set in from the late 1990s, until a nadir of only 12 exploration wells was reached in 2005. Since then, the number has risen sharply. Although the North Sea is regarded as a mature area, it remains the part of the NCS where most wells are drilled.

Exploration wells

"Exploration well" is a collective term for wildcats and appraisal wells.

A wildcat is the first well drilled in a geological structure (prospect).

An appraisal well is drilled to determine the extent and size of a discovery.

Recycling acreage – Utsira High South

The story of Utsira High South embraces blocks 16/1, 2, 3, 4, 5 and 6. Exploration has been pursued there since the first licensing round. The two production licences initially awarded in this area were PLs 001 and 007. Esso was sole licensee for 001, while 007 was awarded to a group of eight licensees with Elf as the operator. Great activity, many players and a highly interesting exploration history have characterised the area since the first wildcats in 1967. Everything from small finds to very large discoveries have been made. The level of activity remains high, and licensees are still hunting for more resources in the area.

All acreage in the blocks originally awarded in PLs 001 and 007 on this part of the Utsira High has been relinquished. It was not until 1984 that one of the relinquished blocks, 16/4, was awarded anew in the eighth licensing round.

The first wildcat found traces of petroleum, but 18 wells had to be drilled on this part of the Utsira High before a commercial discovery was made with Edvard Grieg in 2007. A number of finds have followed, and three fields are now to be developed in the area, almost 50 years since the first awards.

Edvard Grieg, the first of these projects, is due to come on stream in 2015. This field lies in PL 338, awarded in the 2004 APA round, and oil was proven by discovery well 16/1-8. Lundin is operator for the development, with OMT and Wintershall as its partners.

The licensees for 16/1-9 Ivar Aasen are planning production from late 2016. With Det Norske as operator, they discovered oil with well 16/1-9 in 2008. This well lies in PL 001B, awarded in 1999.

Ranked as the largest discovery on the NCS since the 1980s, 16/2-6 Johan Sverdrup was proven in 2010 in PL 501 with Lundin as operator. The latter was awarded the acreage in the 2008 APA round. PL 501 covers parts of blocks 16/2, 3, 5 and 6, which were originally awarded in the first licensing round. They were later awarded in PL 265, which relinquished block 16/3 and parts of 16/2. The 16/2-6 Johan Sverdrup discovery also extends into two production licences operated by Statoil. Roughly 25 appraisal wells have been drilled, and more are scheduled. Plans now call for 16/2-6 Johan Sverdrup to be developed with Statoil as operator for the planning phase.

In other words, despite many wildcats and much recycling of acreage, a massive discovery was waiting to be made. The story of the oldest exploration areas on the NCS is set to continue for many years to come.



Figure 2.1 Area status for the NCS in June 2013.

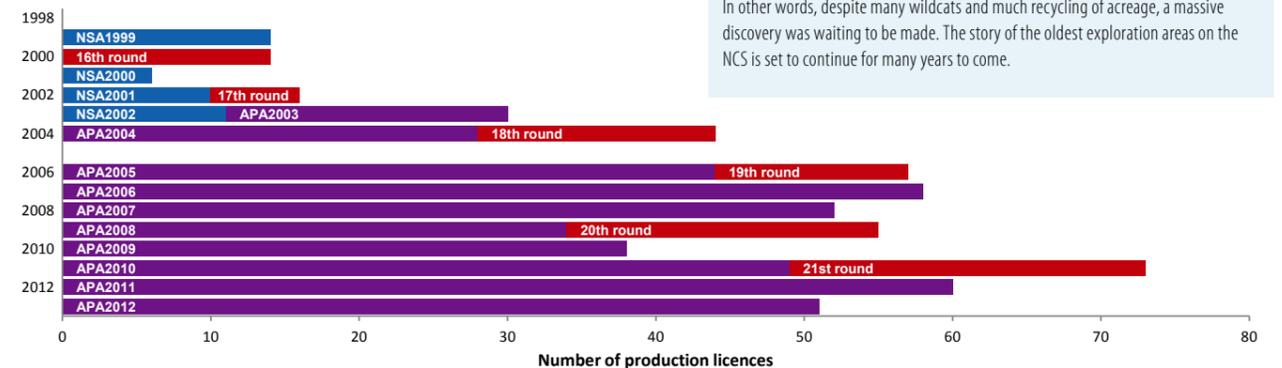


Figure 2.3 Number of licence awards over the past 15 years by licensing round.

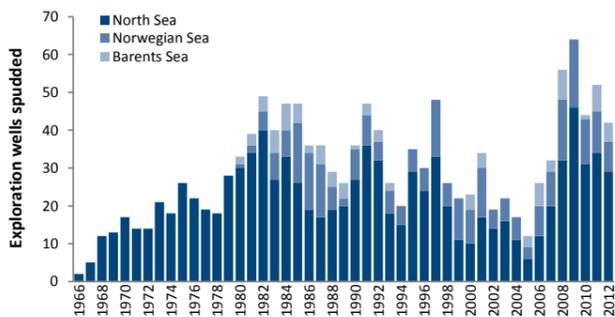


Figure 2.4 Number of exploration wells spudded, 1966-2012.

The rise in the number of exploration wells since 2005 is primarily a result of high oil prices and changes to exploration policy around 2000. See the fact box.

Mobile rigs on the NCS also increased in number from 2005, as figure 2.5 shows. This overview has been prepared by the NPD on the basis of data from the industry. An expansion in rig capacity is expected both globally and on the NCS in coming years.

A number of the rigs which have arrived on the NCS in recent years have been specially designed for operations there. Although many of the new units are chartered to drill on new fields, capacity for exploration drilling will probably increase.

Well over half of all exploration wells on the NCS have been drilled in production licences awarded in the first eight licensing rounds. Roughly 40 per cent have been drilled in licences awarded in rounds one-four. See figure 2.6.

Even over the past five years, a substantial number of exploration wells have been drilled in licences awarded in rounds one-four. See figure 2.7.

About 12 per cent of exploration wells and 13 per cent of wildcats have been drilled in licences awarded in APA rounds, including the North Sea awards. The majority of exploration wells during recent years have been drilled in APA licences, which indicates that increased availability of acreage contributes to a larger number of exploration wells.

Exploration costs

Exploration costs comprise the cost of seismic data acquisition (general surveys), exploration wells, field evaluation and administration. Figure 2.8 shows developments in exploration costs broken down by these cost components.

Changes in operating parameters

Exploration on the NCS was low around 2000, particularly in mature areas. That contributed to low resource growth. To boost such activity, the government implemented changes in the industry's operating parameters. Provision was made in 2000 to admit new companies, and the prequalification of operators and licensees was introduced. This aimed to make it simpler for a new company to secure access to acreage, either through licence awards or through buying/swopping licence interests.

The policy on awarding licences in mature areas was amended in 1999 through the establishment of the NSA scheme, which developed in 2003 into the APA. Active work in mature areas is important for the government, and awards have been made annually since the system was introduced.

An amendment to the Petroleum Taxation Act adopted by the Storting in 2004 gave companies with a tax loss the right to annual refunding of the tax value (78 per cent) of exploration costs with effect from 1 January 2005. Alternatively, such losses can be carried forward as a tax deduction in later years with an interest supplement. This policy aims to put new companies on an equal footing in the exploration phase with established players who already have taxable earnings which allow them to deduct exploration costs in the same year they are incurred.

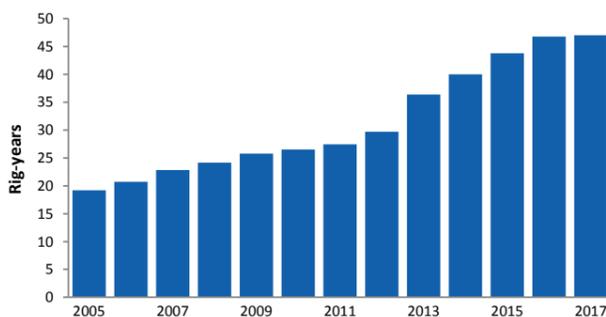


Figure 2.5 Development in the number of mobile rigs on the NCS.

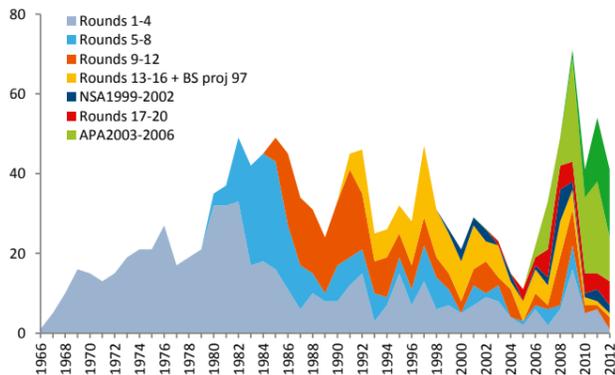


Figure 2.7 Completed exploration wells per year by various licensing rounds.

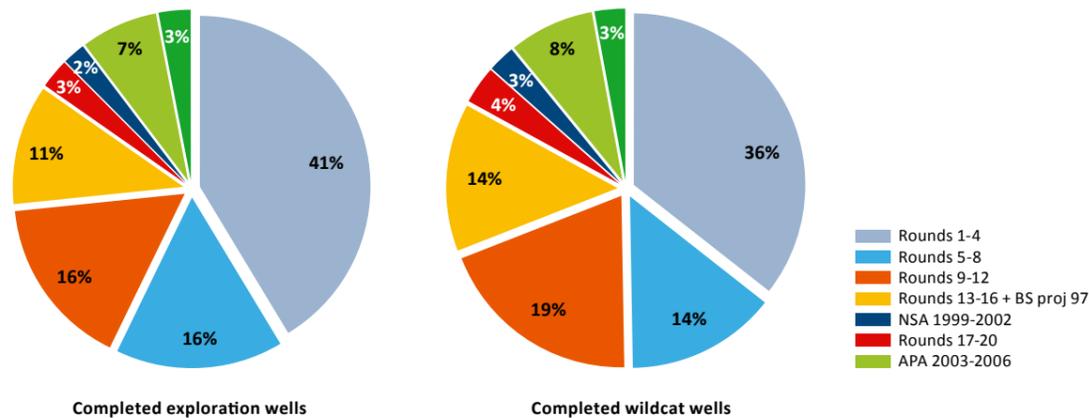


Figure 2.6 The proportion of completed exploration wells and wildcats by licensing round. (Drilling in supplementary awards is allocated to the round when the original licence was awarded.)

Exploration costs develop largely in line with trends for the number of wells drilled. This is hardly surprising, since drilling represents the biggest single factor in total exploration costs. While the number of exploration wells drilled rose, costs per exploration well also increased substantially during the period (figure 2.9).

Drilling costs can be broken down roughly between rig costs and other expenses. Rig costs are determined by the day rate and the number of drilling days. A sharp increase in rig rates has occurred worldwide in recent years, which helps to explain the development in drilling costs per well.

However, rig rates remain higher in Norway than in other petroleum provinces such as the UK continental shelf. According to the Reiten commission, the most important reason for this is higher Norwegian operating costs. (Chaired by Eivind Reiten, the commission was appointed by the Ministry of Petroleum and Energy and submitted its report on rig and drilling capacity on the NCS in August 2012.)

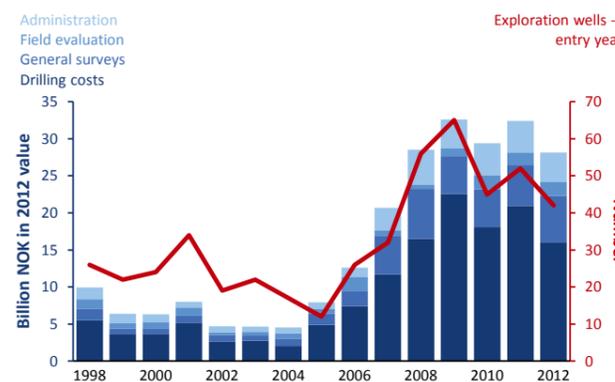


Figure 2.8 Developments in exploration costs and number of wells spudded, 1998-2012.

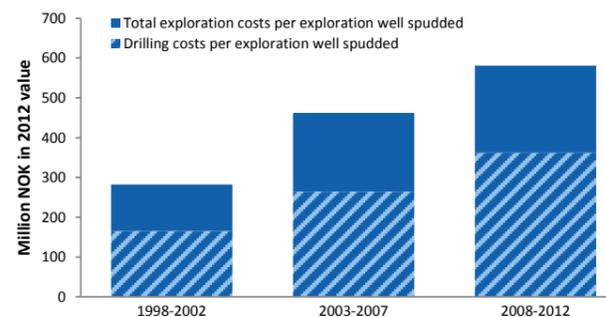


Figure 2.9 Developments in exploration costs per well spudded, past 15 years.

Discoveries

The high level of exploration activity in recent years has resulted in a series of discoveries. Three of the past five years accounted for the largest-ever number of finds on the NCS. See figure 2.10.

A large proportion of these discoveries have been made in acreage awarded in the four first licensing rounds. See figure 2.11. Nothing has so far been found in production licences awarded in the 21st round or the APA 2011 and 2012 rounds, since it takes time for drilling decisions to be taken and wells spudded.

Finding rate rising

The average finding rate (finding success rate) on the NCS has been rising in line with growing knowledge of its geology and with technological advances. Figure 2.12 presents trends for average technical and commercial finding success since 1967. Calculation of

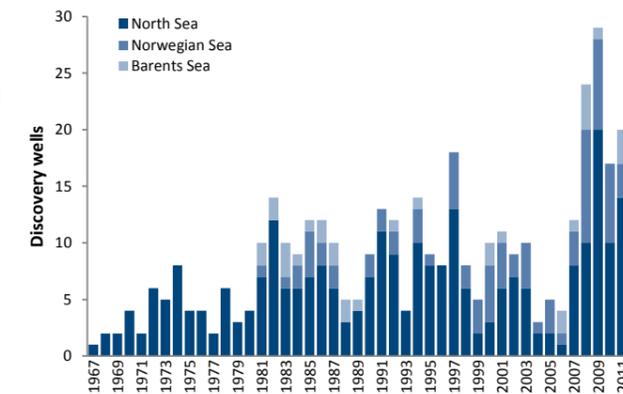


Figure 2.10 Discovery wells per offshore area per annum, 1967-2012.

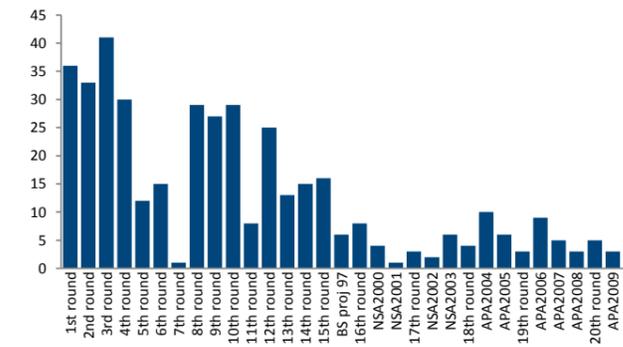


Figure 2.11 Discovery wells per round.

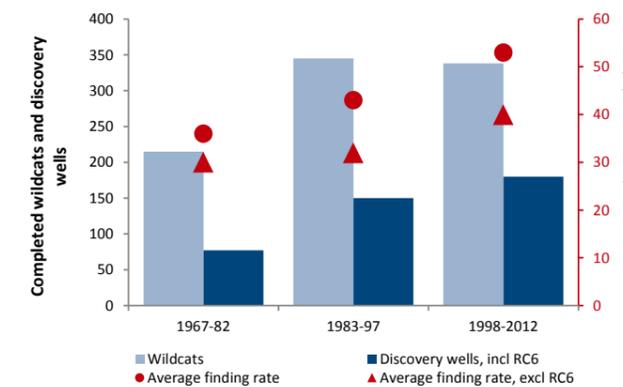


Figure 2.12 Completed wildcats, discovery wells and average finding rate, excluding and including resource category 6 (see box), 1967-2012.

technical finding success includes all discovery wells, while commercial finding success excludes discoveries in resource category 6 (see fact box). Technical and commercial finding rates have averaged about 55 and 40 per cent respectively over the past 15 years.

Resource category 6
Not all discoveries will be developed. Some have been classified by the NPD as discoveries unlikely to be produced. These are ones which are not expected to prove commercial, even in the long term. This category (resource category 6) contains petroleum resources where substantial changes in technology, costs and petroleum prices are required if they are to be brought into commercial production, and where such changes are thought to be unlikely.

Resource category 6 currently contains 108 discoveries, whose resources are not included in the estimate of total recoverable resources on the NCS.

Few examples exist of discoveries placed in this category which have subsequently been developed. However, new discoveries in the vicinity, technological advances and significant changes in the price and cost picture could change conditions for commercial development.

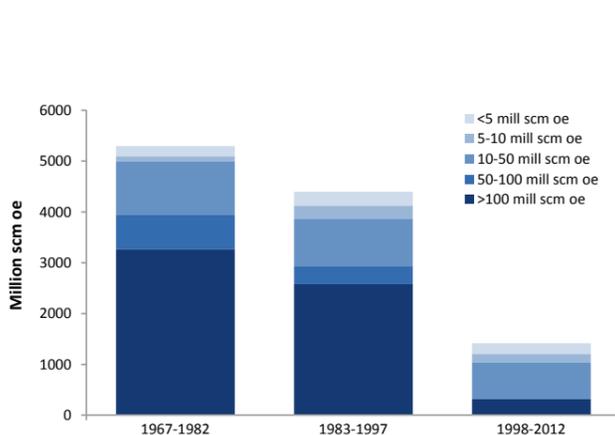


Figure 2.13 Recoverable resources in discoveries proven in 15-year periods by discovery size, 1967-2012.

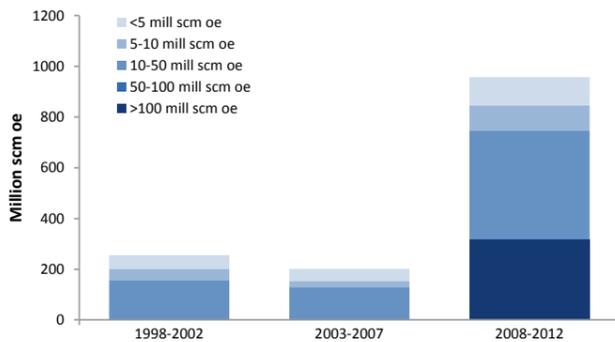


Figure 2.14 Recoverable resources in discoveries proven in five-year periods by discovery size, 1998-2012.

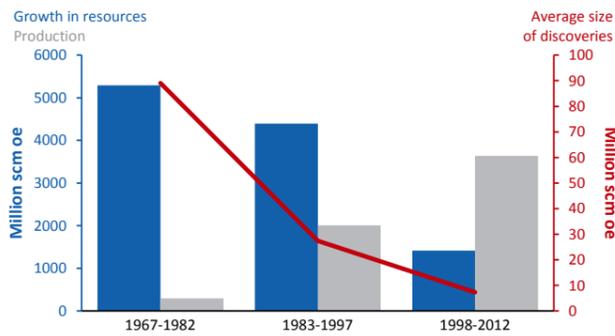


Figure 2.15 Proven recoverable resources in discoveries (resource growth), production and average discovery size, 1967-2012, by 15-year periods.

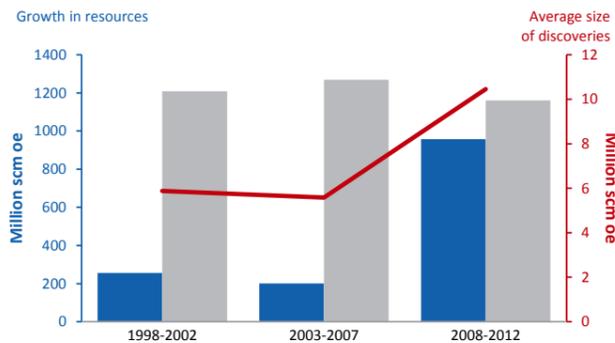


Figure 2.16 Proven recoverable resources in discoveries (resource growth), production and average discovery size, 1998-2012, by five-year periods.

Low resource growth and small discoveries

Although the finding rate is high and many discoveries are being made, resource growth over the past 15 years is substantially smaller than in the two previous 15-year periods. See figure 2.13.

However, the past five years have been positive with several large discoveries, including 16/2-6 Johan Sverdrup in 2010. See figure 2.14.

Resource growth and production

On average, the amount of oil and gas discovered annually on the NCS exceeded annual production during the first 30 years. See figure 2.15. This reflected low output and large discoveries.

Discoveries over the past 15 years have been substantially smaller than the volume produced, reflecting high levels of output and a smaller average discovery size. However, a more detailed analysis of the latest 15-year period shows that the picture is more nuanced. See figure 2.16.

Over the past five-year period, resource growth has been almost on a par with production. The main reason is 16/2-6 Johan Sverdrup, which was discovered in 2010.

Status and development features in the various NCS areas

North Sea – the old are oldest

The North Sea is regarded as a mature region in petroleum terms after almost 50 years of activity. Its exploration history extends right back to 1965, and some 615 wildcats have been drilled so far.

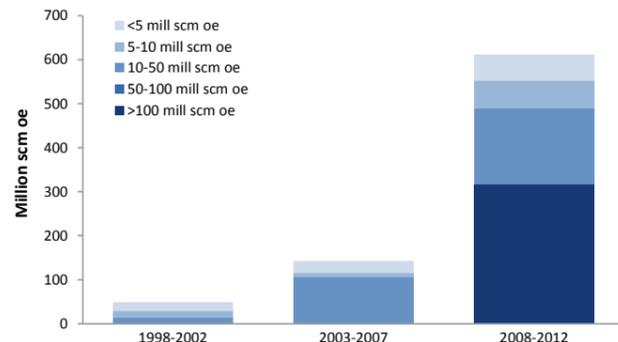


Figure 2.17 Resources in North Sea discoveries by discovery size, 1998-2012.

Exploration activity remains high in the North Sea, with many discoveries. While these are generally small, several large finds have been made over the past five years. They include 16/2-6 Johan Sverdrup on the Utsira High (fact box, page 13). See figure 2.17.

About 100 new production licences have been awarded in the North Sea during 2011-13 through the APA rounds, which will help to maintain exploration activity in coming years.

Norwegian Sea – opportunities and challenges

While parts of the Norwegian Sea are regarded as mature, others – particularly in deep water – remain frontier areas in relative terms. The Norwegian Sea was opened to exploration in 1980, and about 200 wildcats have been drilled since then.

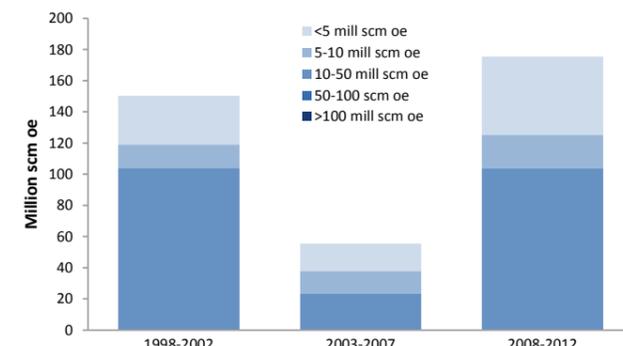


Figure 2.18 Resources in discoveries in the Norwegian Sea by discovery size, 1998-2012.

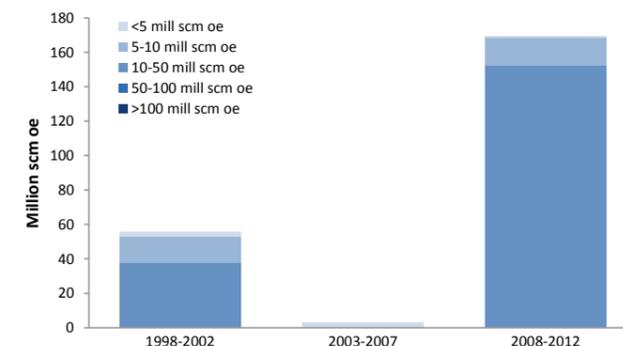


Figure 2.19 Resources in discoveries in the Barents Sea by discovery size, 1998-2012.

Although interest in exploration has experienced a considerable revival in the North and Barents Seas following several large discoveries, exploration results in the Norwegian Sea have been modest in recent years. After an upturn in 2008-10, interest in the Norwegian Sea has been more limited outside the areas close to existing infrastructure. This has contributed to a decline in exploration activity outside the mature parts of the Norwegian Sea during recent years. From 2011 to May 2013, 19 wildcats were completed in the Norwegian Sea and yielded nine discoveries. The finding rate is high, but proven volumes in these discoveries are moderate to small. Only one of the 19 wildcats was drilled outside the existing APA area, in deep water in the Vøring Basin.

No deepwater exploration wells are planned in the Norwegian Sea during 2013, with exploration drilling confined to the APA area. The planned wells will primarily be targeted on the Upper Triassic to Lower Jurassic play in which most Norwegian Sea resources have been proven.

In the deepwater areas, particular work is being done to prepare for seismic surveying beneath the basalt layers adjacent to the Møre and Vøring High and in the westernmost part of the Møre and Vøring Basin.

Exploration history of the Barents Sea

Petroleum activities have been pursued in the Barents Sea since the fifth licensing round in 1980. See the figure below. Roughly 100 exploration wells have been drilled, of which about 80 are wildcats. The first exploration well was drilled in 1980 and the first discovery – 7120/8-1 (Askeladd) – followed in 1981. More than 30 discoveries have been made in the Barents Sea. Some are not expected to be commercial and are grouped in resource category 6.

Although oil operations have been pursued in the Barents Sea for more than 30 years, only one field has come on stream – Snøhvit, which comprises eight gas discoveries. The Goliat oil field is also under development.

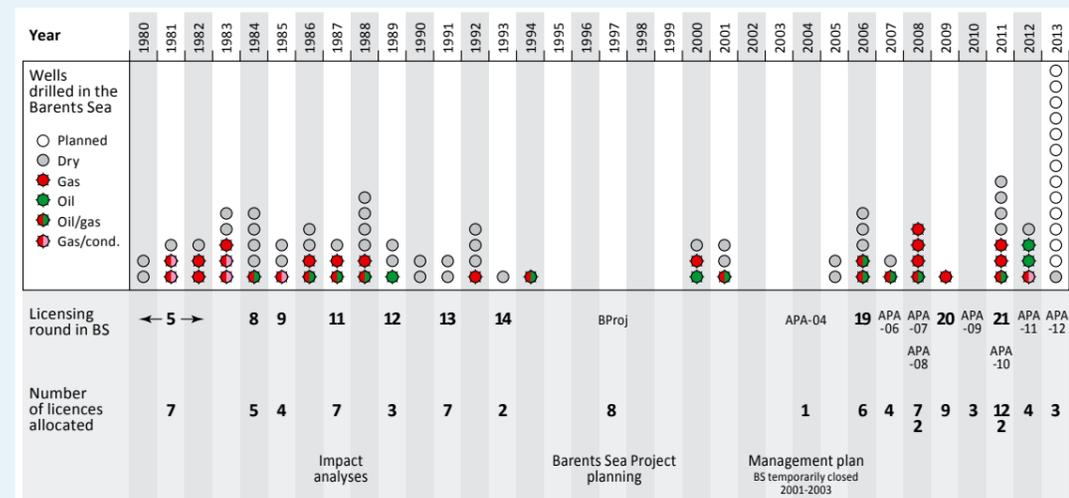
Optimism was high in the early 1980s, when several gas discoveries were made in the Hammerfest Basin. A number of wells drilled outside that basin after 1986 were either dry or contained only small gas resources. Interest in exploring the area waned as a result, and not a single well was drilled between 1994 and 2000. In 1997, the government launched a Barents Sea project to promote and increase exploration activity. Special measures and terms resulted in the offer of both conventional production licences and large areas for seismic surveying. Operator Norsk Agip (now Eni) found both oil and gas in PL 229 during 2000, and this discovery was named Goliat.

The government suspended activities in 2001 to await the impact assessment for year-round petroleum activities off Lofoten and in the Barents Sea (ULB). In December 2003, the govern-

ment resolved to permit a resumption of petroleum operations in the southern Barents Sea. The companies showed some interest, particularly because of Goliat.

Interest in the blocks which embrace the Skrugard structure was low in the 19th round, and this acreage was not awarded. New three-dimensional seismic data acquired in connection with the 20th round showed direct hydrocarbon indicators more clearly, particularly "flat spots". A double flat spot identified on the Skrugard structure was interpreted to mean that it probably contained both oil and gas. Combined with a positive result from electromagnetic (EM) surveys, this attracted several companies.

Johan Castberg (7220/8-1 Skrugard and 7220/7-1 Havis) was discovered in 2011. Gas and oil were proven in Jurassic rocks. As expected, the double flat spot seen on the seismic map proved to represent the gas-oil and oil-water contacts. The industry is working to find explanations for why the petroleum system functions in this area. Large parts of the Barents Sea have been subject to uplift and erosion, with many of the strata eroded away so that the petroleum has leaked out. The gas leakage is clearly visible in the seismic data, including above the Skrugard structure, but has probably acted there as a form of safety valve. Because the gas leaks out, it does not expand in the reservoir and drive out the oil. In addition, the source rock lies at a favourable depth for also generating oil and gas today. This means that the traps could be dynamically refilled with petroleum to compensate for the leakage – not unlike the petroleum systems in the North Sea.



The players

The 21st licensing round resulted in a number of new licences around the Aasta Hansteen gas discovery, whose forthcoming development will be important for proving more gas in the area in coming years. Fourteen Norwegian Sea blocks are on offer in the 22nd round, all in the Vøring Basin.

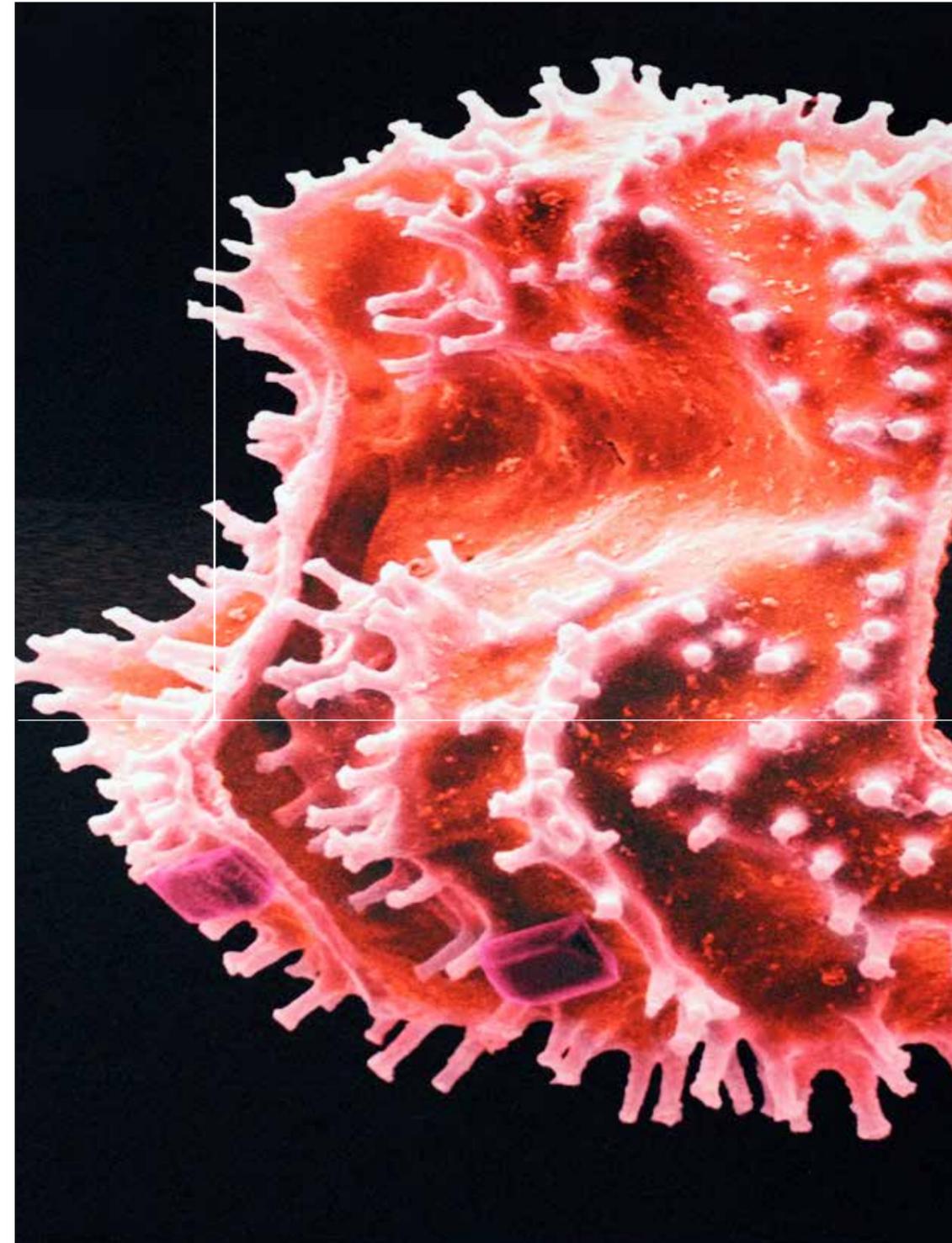
After several years of limited exploration activity in the Møre Basin in the southern Norwegian Sea, a number of new licences have been awarded in the south of the basin around the Ormen Lange field and in the basalt region farthest to the west. These licences were awarded in the 20th and 21st licensing rounds and in the 2010 APA round. Evaluations under way in a number of them will result in drill or drop decisions within one to three years.

Barents Sea – new optimism

After many years of disappointment, optimism has returned to the Barents Sea, primarily because of three discoveries made in 2011-12 – the Johan Castberg oil find (7220/8-1 Skrugard and 7220/7-1 Havis) and the 7225/3-1 (Norvarg) gas discovery. See figure 2.19.

Good exploration results over the past two years have generated great interest in Barents Sea drilling. The NPD expects some 10-14 wells in the Barents Sea during 2013.

The Hoop area is the northernmost part of the NCS where acreage has been awarded, and oil discoveries are possible. A number of wells are due to be drilled there over the next few years.



3

The player picture

A variety of participants plays a key role in achieving the highest possible value creation for society from petroleum operations on the NCS. It is important that the player picture reflects the challenges facing the industry in both mature and frontier areas, and that the companies play an active role.

Oil prices were around USD 10 per barrel in the late 1990s, prompting a substantial consolidation of the oil sector. Mergers internationally involved such companies as Conoco and Phillips, BP, Amoco and Arco, Total, Fina and Elf, Chevron and Texaco, and Exxon and Mobil. In Norway, Hydro and Saga were among those to merge.

This consolidation had direct consequences for the player picture, with the international companies becoming fewer and larger. That coincided with the development of the NCS, and the North Sea in particular, into a more mature petroleum province where the declining size of discoveries presented different challenges than before. Opportunities in the mature areas of the NCS were of limited interest to several of the existing players.

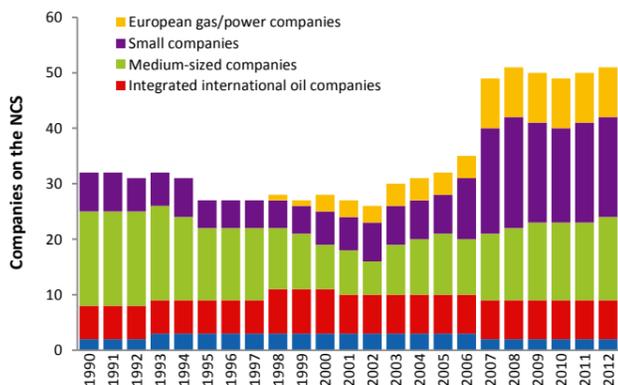


Figure 3.1 Companies on the NCS in 1990-2012 by company type.

The Norwegian government accordingly implemented several measures to boost value creation from mature areas (see fact box, page 14). A key change was to permit more companies to become licensees and to introduce the prequalification scheme. Small and medium-sized oil and gas companies and foreign energy and downstream enterprises became established on the NCS. So did a number of new Norwegian companies. See figure 3.1. This almost doubled the number of participants on the NCS in 2002-07, and led to a more diversified player picture.

Reserves and resources

Large Norwegian companies owned about 65 per cent of remaining NCS reserves at 31 December 2012 (see the fact box on page 9

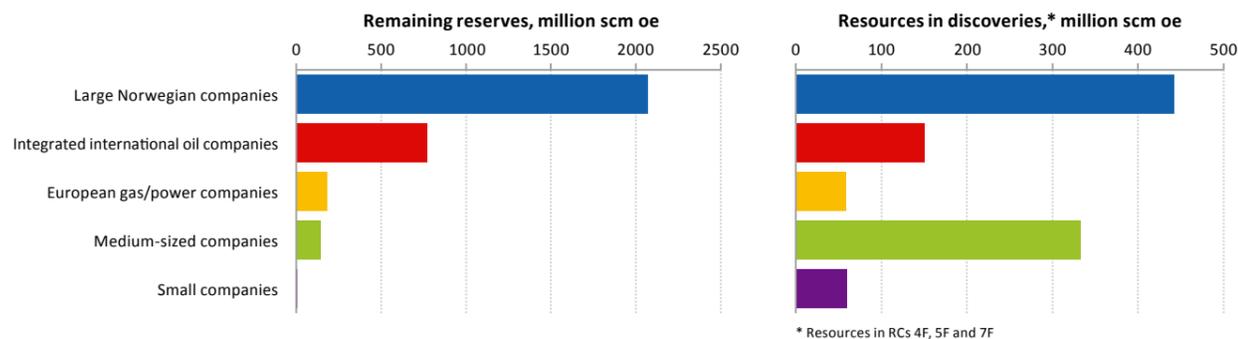


Figure 3.2 Remaining reserves and resources in discoveries on the NCS at 31 December 2012.

Various company types

The NPD has divided players on the NCS from 1965 to 31 December 2012 into five types: large Norwegian companies, integrated international oil companies, medium-sized companies, European gas/power companies and small companies. Table 3.1 presents the breakdown of players active as licensees on the NCS today. Petoro is defined as a large Norwegian company, even though it is not an oil company in the usual sense but acts as the licensee on behalf of the government. Allocation to the various groups is based on a combination of size, nationality and phase (strategy). Size is defined by the enterprise's market value on the stock exchange. Medium-sized companies lie in the USD 1 000-5 000 million range and small ones in USD 0-1 000 million. The transfer of companies between different categories has been preserved historically, since they mainly change type as a result of mergers. Over the past 15 years, only Det Norske has changed company type on the basis of discoveries which have altered its market value on the stock exchange.

Large Norwegian companies	Statoil, Petoro
Integrated international oil companies	BP, Chevron, ConocoPhillips, Eni, ExxonMobil, Shell, Total
European gas/power companies	Bayerngas, Centrica, Dong, E.ON, Edison, GDF Suez, PGNiG, RWE Dea, VNG
Medium-sized companies	BG, Cairn, Det Norske, Hess, Idemitsu, Lotos, Lundin, Maersk, Marathon, OMV, Premier, Repsol, Suncor, Talisman, Wintershall
Small companies	Bridge, Concedo, Core, Dana, Emergy, Explora, Faroe, Fortis, Noreco, Norske AEDC, North, Petrolia, Rocksource, Skagen44, Skele, Spring, Svenska, Valiant

Table 3.1 Company classification of licensees on the NCS at 31 December 2012.

for an explanation of the terms used), while integrated international oil companies held roughly 24 per cent. Collectively, these companies possessed almost 90 per cent of the remaining reserves. The rest of the remaining reserves were held by European gas/power companies (about six per cent), medium-sized companies (five per cent) and small companies (0.3 per cent). See figure 3.2.

About 42 per cent of resources in discoveries (resource categories 4F, 5F and 7F) are held by large Norwegian companies, and 32 per cent by medium-sized companies. The remainder is divided between integrated international oil companies (14 per cent), European gas/power companies (six per cent) and small companies (six per cent).

Production licences

In addition to owning the largest proportion of reserves and resources in discoveries, large Norwegian companies hold the greatest number of production licences. See figure 3.3.

Holdings of production licences by companies are the result of

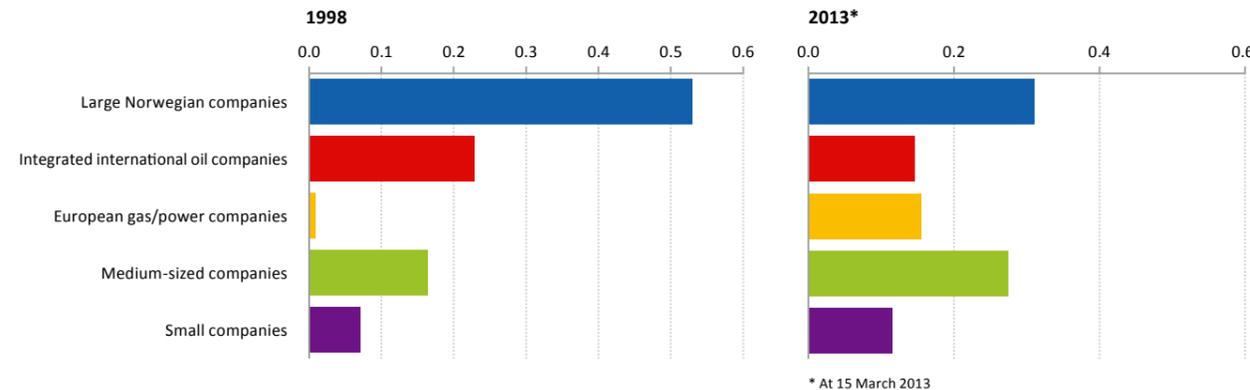


Figure 3.3 Share of production licences by company type on the NCS in 1998 and at 15 March 2013.

applications in licensing rounds, farm-ins/outs and swops of interests in such licences, and company acquisitions. The breakdown of production licences between the various company types has altered from 1998 to 2013 as a result of the political changes described in chapter 2.

At 15 March 2013, large Norwegian companies held 31 per cent of the production licences on the NCS, compared with 53 per cent in 1998. So the proportion of licences possessed by such enterprises declined. The integrated international oil companies have also seen their share of production licences reduced, from roughly 23 per cent in 1998 to 15 per cent in 2013. Collectively, these two categories of companies hold roughly 46 per cent of the production licences on the NCS today, down from about 76 per cent in 1998.

The category with the second largest share of production licences today is medium-sized companies, which has grown from some 16 per cent in 1998 to roughly 27 per cent in 2013. European gas/power companies and small companies collectively hold 27 per cent of production licences.

Awards

Large Norwegian companies secured the biggest share of licence awards in 1965-97. How many licences the various companies obtain in licensing rounds depends both on the number of applications they submit and the extent to which they meet government criteria for such awards. Medium-sized companies have secured the largest proportion of awards over the past 15 years, closely followed by small companies and large Norwegian companies. Integrated international oil companies had the smallest share. See figure 3.4.

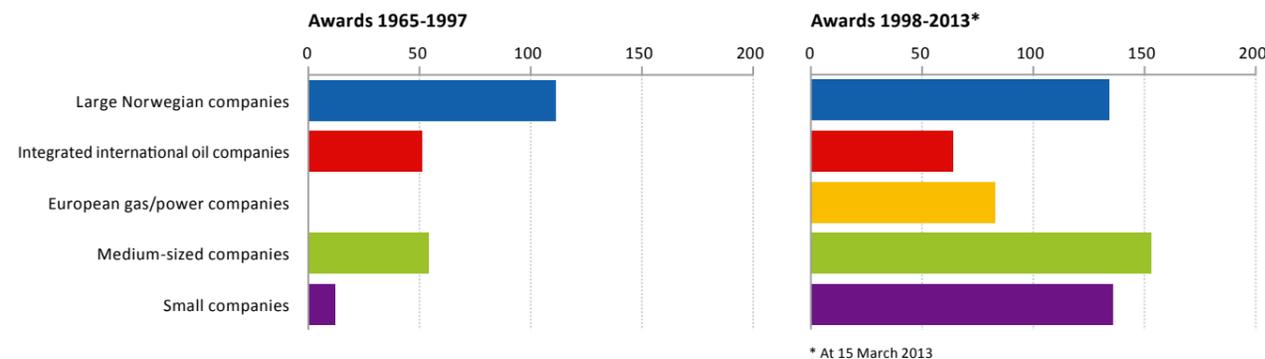


Figure 3.4 Awards by company category in 1965-97 and 1998-15 March 2013.

The number of licensing rounds and awards per round have increased over the past 15 years. See figure 3.5. That has made it possible for medium-sized, small and European gas/power companies to increase their share of production licences. These categories have been very successful in rounds since 2005, particularly the APA rounds in mature parts of the NCS. Awards to large Norwegian and integrated international oil companies have been fairly stable, although their share has declined.

While medium-sized and small companies have secured almost half the licences awarded in the APA and NSA in mature areas in the period from 1999 to 15 May 2013, large Norwegian and integrated international oil companies obtained the largest proportion of awards in frontier areas from the numbered rounds in the same period. See figure 3.6.

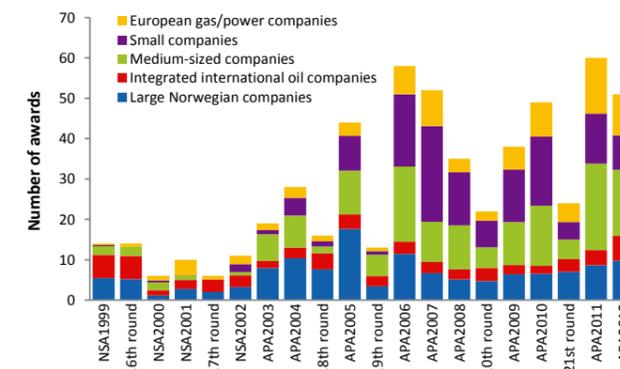


Figure 3.5 Awards per round from the NSA of 1999 to the 2012 APA round, by company type.

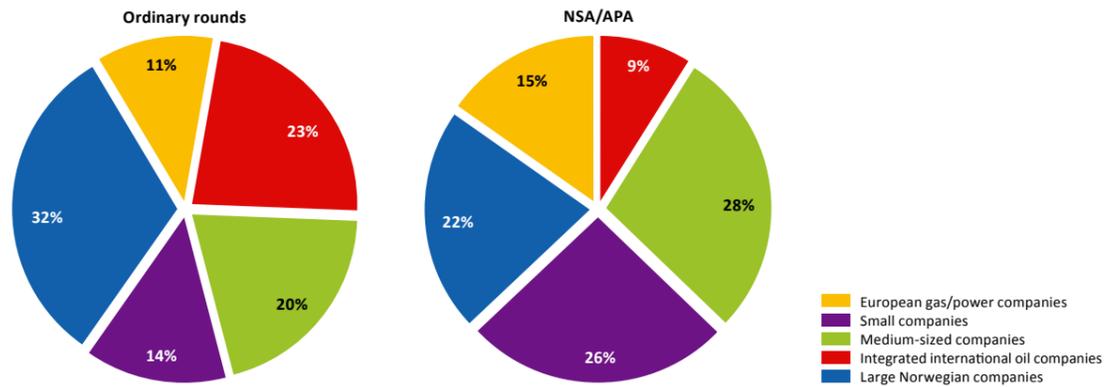


Figure 3.6 Share of awards per company type by numbered rounds and APA/North Sea awards from the 1999 North Sea awards to the 2012 APA round.

Secondary market

The secondary market has expanded substantially over the past 15 years, in line with the increasing number of companies on the NCS, the growth in the number of production licences and the development of oil prices. See figure 3.7. Large Norwegian and integrated international oil companies were active buyers up to 2005, but have been relatively inactive with farm-ins since then. Medium-sized, small and European gas/power companies have been the most active buyers after 2005.

Medium-sized companies have also been among the most active sellers in the secondary market over the past five years, along with small companies. Big integrated oil companies were very active sellers in 2003-07. See figure 3.8.

Exploration costs

Large Norwegian and medium-sized companies have secured the largest share of new acreage from licensing rounds over the past 15 years. These two groups collectively hold 50 per cent of production licences on the NCS. Where ownership of such licences is concerned, medium-sized companies appear to have taken over the position previously occupied by integrated international oil companies. Large Norwegian and medium-sized companies have also had the biggest exploration costs over the past six years. Such costs have been relatively stable for integrated international oil companies over the past 15 years, although their share of the total has declined. Exploration costs have risen sharply for European gas/power and small companies since 2007.

Resource growth

Large Norwegian and medium-sized companies invest the biggest sums in exploration. Together with the integrated international oil companies, they are also responsible for finding the most

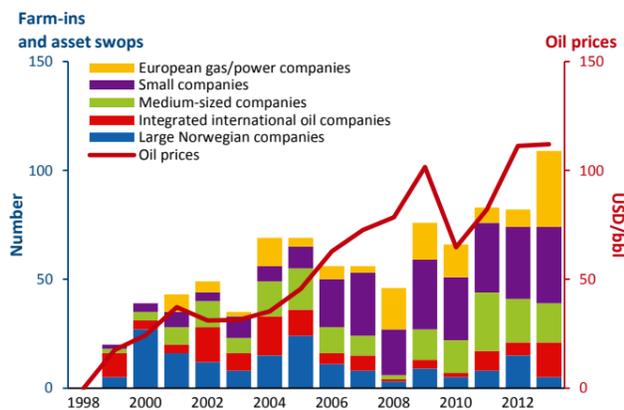


Figure 3.7 Farm-ins and swops to interests in production licences over the past 15 years.

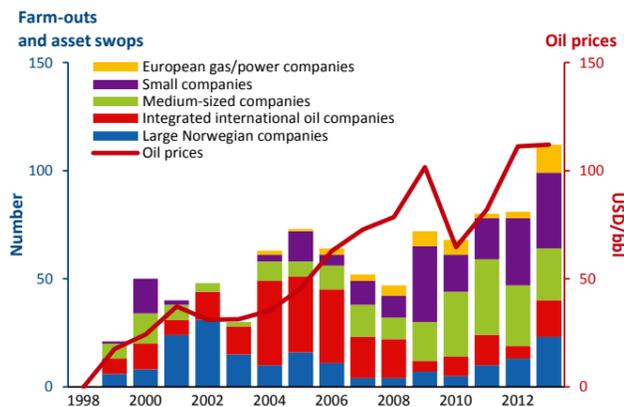


Figure 3.8 Farm-outs and swops from interests in production licences over the past 15 years.

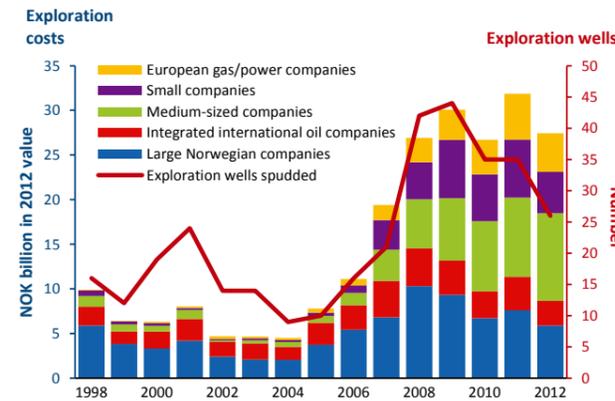


Figure 3.9 Exploration costs by company type over the past 15 years. The red curve shows the number of exploration wells spudded per annum.

resources. See figure 3.10, where resource growth is attributed to the licence which has drilled the exploration well.

A comparison of resource growth per NOK 1 000 spent on exploration over the past five years shows that large Norwegian and medium-sized companies achieved the best return on their spending in this period. Resource growth per exploration krone for European gas/power and small companies was also positive, but lower than for the other company types. See figure 3.11.

The conclusions drawn from such an analysis must not be exaggerated, since the analysis may undervalue the benefits which a diversified player picture can confer. A number of small companies, for example, have developed prospects which are later acquired by larger players – either by farming into production licences or by taking over whole companies. When these prospects are drilled and discoveries made, resource growth is attributed to the new owner. The analysis fails to pick up this value creation.

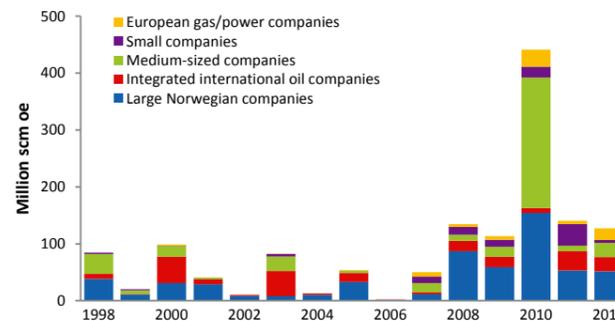


Figure 3.10 Resources in discoveries by company type over the past 15 years, by equity interests.

Diversity

The changes made by the Norwegian government to its exploration policy roughly a decade ago helped to almost double the number of participants on the NCS in 2002-07, and the player picture became more diversified. This has yielded good results, with greater exploration activity and more discoveries.

According to the NPD's analysis of the contributions made by the players to the increase in exploration activity, all company categories have contributed positively to both exploration activity and results. A particular feature of the analysis is that medium-sized companies appear to have taken over the position held by integrated international oil companies on the NCS since activities began there almost 50 years ago in terms of number of production licences, licence awards and exploration. Together with large Norwegian companies, the medium-sized companies have made the biggest investment in exploration over the past 15 years. These company categories have also been responsible for the biggest resource growth.

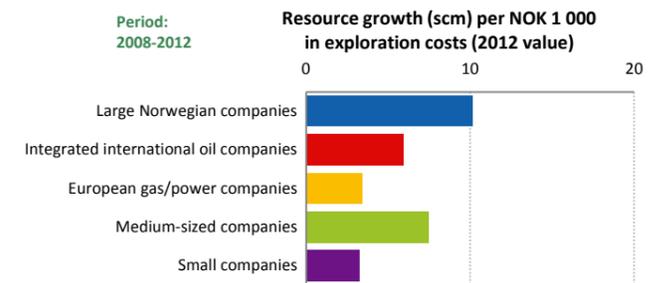
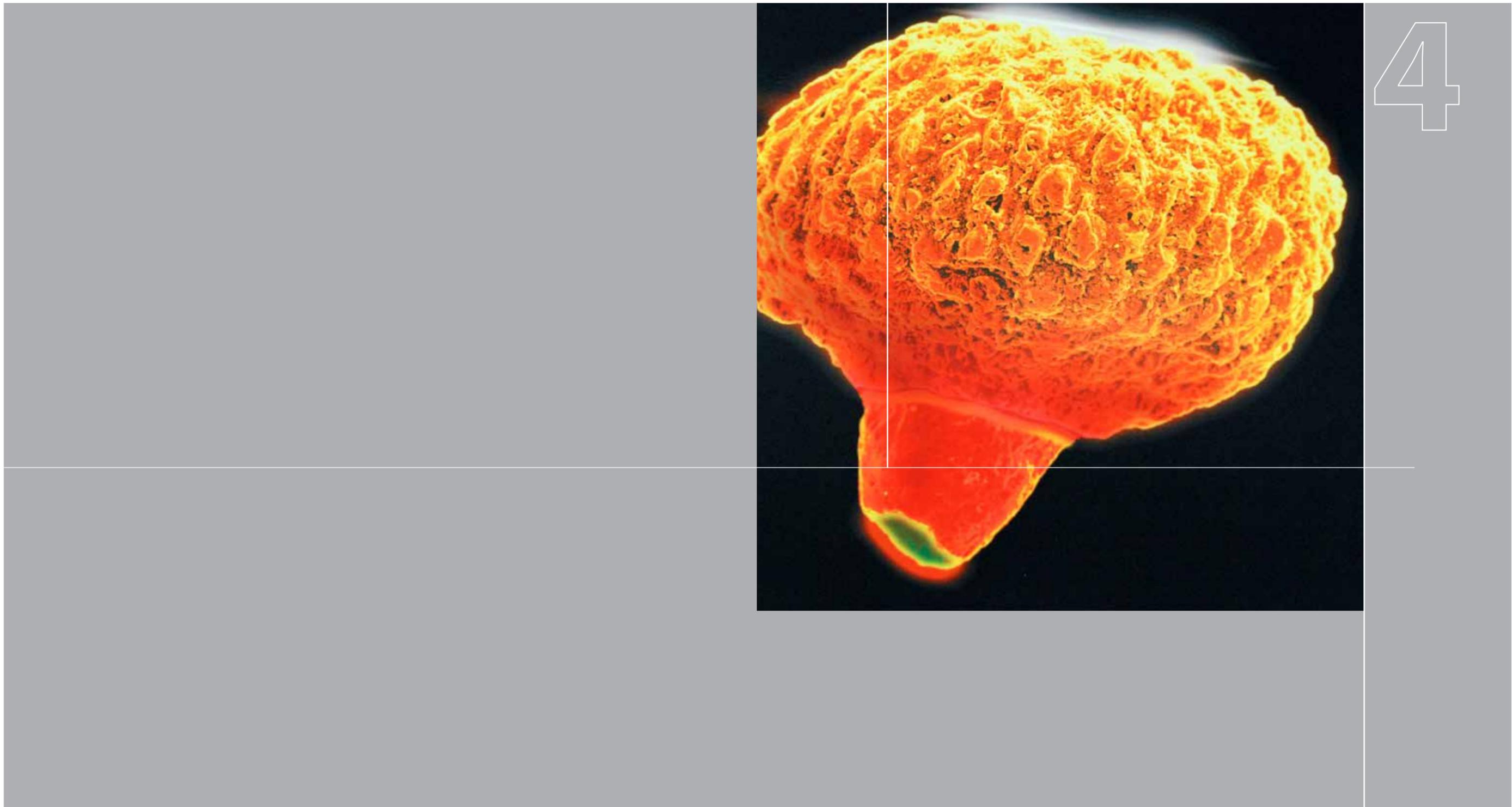


Figure 3.11 Resource growth per NOK 1 000 spent on exploration by equity interest 2008-12, by company type.

More small and European gas/power companies have become participants on the NCS since the policy changes were made. They are also securing a growing proportion of licence awards and account for an increasing share of exploration investment. While their resource growth is lower than for the other company categories, it is on the increase. However, the NPD's analysis may underestimate the value of the contribution made by small companies because these are often taken over, with possible resource growth then being attributed to their new owner.

Undiscovered resources



Producing estimates of undiscovered resources on the NCS is a key part of the NPD's work. These calculations are important for the choices made by government with regard to offshore exploration.

The estimates of undiscovered resources are based on the NPD's knowledge and on information from the industry's exploration of the NCS. Their starting point is geological mapping of areas both opened and unopened for petroleum activities. Knowledge of reservoirs already proven is also important, along with an understanding of how much of the proven resources can be recovered. This rests on the factual basis acquired by the NPD from wells, discoveries, fields, prospects and plays (see the fact box about plays on page 29).

After almost 50 years of petroleum operations, the factual basis is substantial and knowledge of petroleum geology conditions great. But large areas still exist where geological data are relatively limited. Moreover, exploration history shows that areas regarded as mature can surprise with large discoveries. Uncertainty about the size of undiscovered petroleum resources on the NCS accordingly remains high despite half-a-century of exploration.

Estimated undiscovered recoverable resources

The NPD calculates that 935 to 5 420 million scm oe remain to be discovered on the NCS, with an expected value of 2 980 million scm oe (see table 4.1).

This estimate embraces the whole NCS with the exception of the new area in Barents Sea North-East acquired under the maritime delimitation treaty between Norway and Russia. See figure 2.1.

Area	Low/ P95	Expected/ average	High / P05
North Sea	485	850	1 315
Norwegian Sea	240	780	1 795
Barents Sea	245	960	2 475
Barents Sea South-East	55	300	565
Jan Mayen	0	90	460
NCS total	935	2 980	5 420

Table 4.1 Undiscovered recoverable resources broken down by area. The estimates are presented as the expected (average) value, low estimate (P95) and high estimate (P05) in million scm oe.

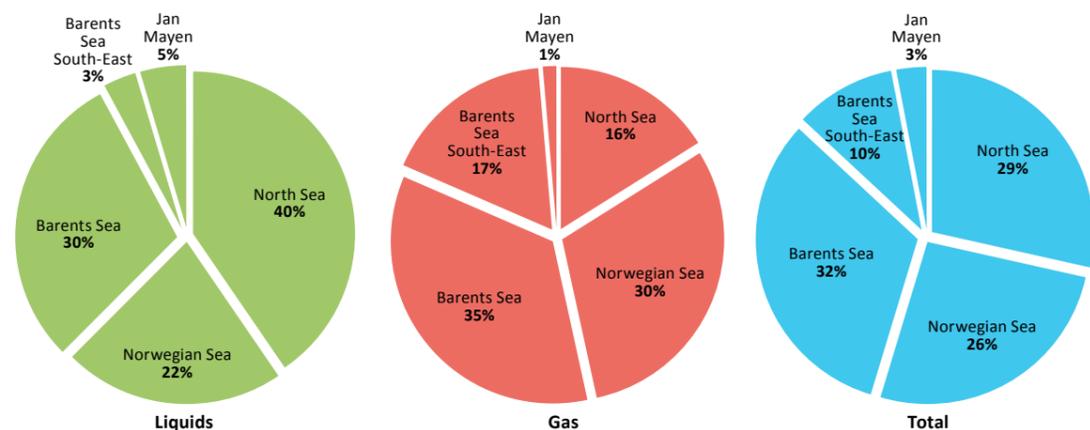


Figure 4.2 Undiscovered recoverable resources of liquids, gas and total resources broken down between the various parts of the NCS, excluding Barents Sea North-East.

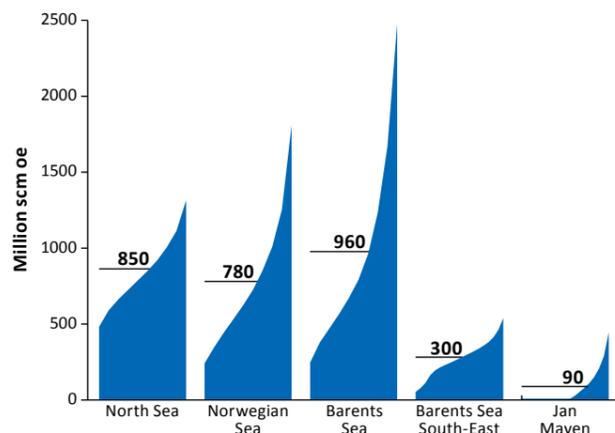


Figure 4.1 The estimate for undiscovered recoverable resources with its uncertainty range, broken down by the various parts of the NCS.

The NPD's estimate of total undiscovered resources on the NCS has increased since the previous resource report was published in 2011, when the expected resource estimate was 2 570 million scm oe. It is now 410 million scm oe higher. The main reason for this rise is that undiscovered petroleum resources in Barents Sea South-East and around Jan Mayen, recently mapped by the NPD, have been included in the resource estimate. Results from the seismic mapping and the resource estimates were presented by the NPD this February. The geology of and resource estimates for these areas are described in chapters 6 and 7 of this report.

Estimates of undiscovered resources are very uncertain. The uncertainty is greatest in areas with the least information and the shortest exploration history.

A preliminary aggregation and uncertainty calculation for the undiscovered resources, including Jan Mayen and Barents Sea South-East, provides an uncertainty range of 935 to 5 420 million scm oe (table 4.1). Resource estimates for the various regions, with uncertainty range, are presented in figure 4.1.

The liquid potential is expected to be greatest in the North Sea, while the gas potential is highest in the Barents Sea. See figure 4.2. Should discoveries be made, gas is most likely to be found in Barents Sea South-East and oil around Jan Mayen.

Incorporating resource estimates for the recently mapped areas raises the proportion of undiscovered resources from 19 to 21 per

cent of total recoverable resources (including those produced and sold) compared with the estimate of 31 December 2012 presented in the fact box on page 10 and in the *Facts 2013* publication.

Method for calculating possible petroleum resources

The calculation of possible petroleum resources in an area builds on a good understanding of the regional geology as well as an overview of prospects and how much petroleum each prospect might produce. Prospects are the main elements in a play. In a little-known area, uncertainty will prevail about

- the total resources
- the geographical distribution of the resources
- the distribution of resources by size
- the division between oil and gas in the resources.

Several methods are available for estimating how much oil and gas might have been formed and deposited in an area. The choice of method depends on how much is known about the area.

The NPD's preferred method is play analysis. This involves systematising and describing the geological understanding of an area. Plays are then defined as the basis for calculating how much petroleum might be proven in and produced from each play.

Prospects provide the fundamental elements in play analysis, and the number of prospects and how much petroleum each of them might produce determines the estimated resources for the play. A prospect is a potential petroleum deposit which has been mapped and where the quantity of possible producible petroleum can be calculated. The number of possible discoveries is calculated by applying a common probability of success to the prospects in a play. This uses information from each prospect along with knowledge of the discovery success for the play. The size of possible discoveries is also assessed, based both on the estimated size of each prospect and on an evaluation of the relationship between assumed and actual discovery sizes. The likelihood that an exploration well might prove producible petroleum in the prospect is called the probability of success. New information from the seismic interpretation and drilling results are used by the NPD regularly to update and adjust its resource estimates for the relevant plays.

A *play* is characterised by geological factors which are simultaneously present in a clearly delineated area (basin), both stratigraphically and geographically, source rocks and a trap (see the fact box on page 29). Mapped and unmapped prospects, discoveries and fields can be found in a single play (figure 4.3).

Several plays of differing geological age can be found in a single geographical area – one with a reservoir rock from the Late Triassic, for example, and another from the Middle Jurassic.

Whether a play contains petroleum is uncertain until a discovery has been made in it. If producible petroleum has not been proven in a play, it is *unconfirmed*. Before the play is confirmed, the level of uncertainty must be taken into account. The likelihood that the play will work can be calculated by assessing the geological factors and the probability that these will work. Resource estimates rise when a play is confirmed. A confirmed play is characterised by a discovery which has proven producible petroleum. The discovery does not need to be commercial.

The less knowledge exists about a play, the more uncertain are its estimated resources. Estimated resources are specified by the NPD with an uncertainty range. Uncertainty is greatest in the Barents Sea, where exploration began in 1980. The fewest wells have been drilled there, and most plays remain unconfirmed. Exploration in



Figure 4.3 The relationship between basin, play, discovery and prospect.

the North Sea began in the mid-1960s, and uncertainty there is less because more plays have been confirmed by discoveries.

Seventy-three plays have been identified by the NPD on the NCS, of which 40 have been confirmed by discoveries. The status for plays at 31 December 2012 is presented in table 4.2. Plays in Barents Sea South-East and around Jan Mayen are not included in this analysis.

Changes to estimated undiscovered recoverable resources from end-2010 to end-2012.

The NPD regularly updates undiscovered resources on the NCS. Since the previous estimate in 2010, substantial mapping has been conducted both by the industry and by the NPD in connection with the APA and numbered rounds. Exploration results in recent years are also crucial for assessing undiscovered resources. The resource assessments for Barents Sea South-East and around Jan Mayen are not included in the estimates at 31 December 2012.

Area	Number	Status	
		Confirmed	Unconfirmed
North Sea	24	19	5
Norwegian Sea	22	11	11
Barents Sea	27	10	17
Total	73	40	33

Table 4.2 Plays defined by the NPD by area and status. A play is confirmed when a discovery has been made in it.

Minor changes to the estimate for undiscovered resources at 31 December 2010 were made at 31 December 2012. These showed a small increase of roughly one per cent in the expected estimate, from 2 570 million scm oe to 2 590 million. Many and to some extent large discoveries have been made since the previous analysis. Rather than reducing the volume of expected undiscovered resources, these finds provided new knowledge which has helped to increase expected undiscovered resources on the NCS (figure 4.4).

Expectations up for liquids

Little change occurred in the division between liquids and gas from 2010 to 2012. The expected value for liquids increased by six per cent, from 1 315 million scm to 1 400 million (figure 4.5). This estimate does not include Barents Sea South-East or Jan Mayen.

Estimated liquid volume has increased first and foremost in the North and Barents Seas. The largest change is in the North Sea,

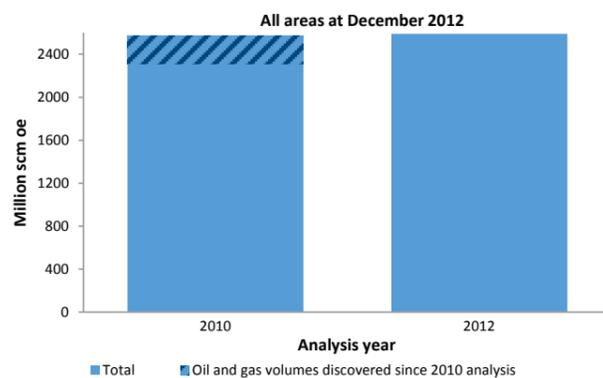


Figure 4.4 Comparison between the 2010 and 2012 analyses for total undiscovered resources. The shaded area indicates the volume of discoveries since the 2010 analysis at 31 December 2012.

with the expected estimate up by 50 million scm oe or nine per cent from the 2010 analysis. Very little change occurred in the Norwegian Sea. Four plays in the North Sea contributed to the increase. A new play has been defined over the southern Utsira High, where several substantial discoveries have been made in recent years – including 16/2-6 Johan Sverdrup and Edvard Grieg. The NPD's earlier plays in this area did not reflect the special depositional environment which has now been identified in this part of the Utsira High. Embracing rocks ranging from the basement to the Cretaceous, the play is expected to contain mostly oil.

Following discoveries in the Upper Triassic to Middle Jurassic play in the northern North Sea over the past five years, expectations for the liquid/gas ratio have been adjusted and the probability of finding liquids has risen.

In addition, the number of prospects in two Upper Jurassic plays has been increased. One of these plays is in the north-eastern North Sea, where such discoveries as 35/9-8 (Skarfjell) have generated optimism and led to several new prospects being mapped. The other is at the southern end of Norway's North Sea sector, where several new prospects have also been mapped following discoveries such as 8/10-4 S (Butch) and 2/4-21 (King Lear), which all help to boost expectations.

Expectations for liquids in the Barents Sea have risen by 25 million scm (six per cent) from 2010. This increase primarily reflects a reassessment of the Lower to Middle Jurassic play, which contains the Johan Castberg (7220/8-1 Skrugard and 7220/7-1 Havis) oil discovery. It was earlier assumed that this play largely contained gas and that reservoir quality was poorer than the wells have demonstrated. The play has now been revised, and is expected to be three times larger with a higher oil potential. In addition, the potential in the overlying Upper Jurassic to Lower Cretaceous play has been upgraded for both liquids and gas.

Liquid resources including Barents Sea South-East and around Jan Mayen

Resource estimates for Barents Sea South-East and around Jan Mayen (see chapters 6 and 7) provide a new figure for the total resources in the Barents and Norwegian Seas. The expected value for liquids has risen by 8.6 per cent, from 1 400 million scm at 31 December 2012 to 1 520 million scm (figure 4.4).

The increase in the expected value for total liquid resources breaks down into 50 million scm in Barents Sea South-East and 70 million scm around Jan Mayen.

Expectations down for gas

The estimate for expected undiscovered gas resources on the NCS has been reduced by 65 billion scm or five per cent (figure 4.6). This figure does not include Barents Sea South-East and Jan Mayen.

In the North Sea, the estimate for expected undiscovered gas resources has been reduced by 16 per cent in the 2012 analysis, from 280 million scm oe to 235 million. This is because a greater expectation of liquids in some plays has reduced the expectation of gas in the same plays.

The position in the Norwegian Sea is virtually unchanged, with a small reduction of two per cent in expectations for gas.

A two per cent reduction from the 2010 analysis has also been made in the Barents Sea.

Gas resources including Barents Sea South-East and around Jan Mayen

Resource estimates for Barents Sea South-East and around Jan Mayen (see chapters 6 and 7) provide a new figure for total resources in the Barents and Norwegian Seas. The expected value for gas has risen by 23 per cent from the estimate of 1 190 million scm oe at 31 December 2012 to 1 460 million (figure 4.5).

The increase in the expected value for total gas resources breaks down into 250 million scm oe in Barents Sea South-East and 20 million scm oe around Jan Mayen.

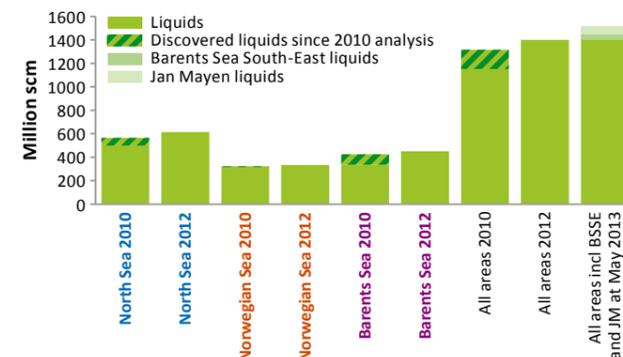


Figure 4.5 Comparison of expected undiscovered recoverable liquid resources in the three parts of the NCS and in the total area (2010 and 2012 analyses). The shaded areas indicate how much liquid has been found since the 2010 analysis. The potential for the whole NCS, including Barents Sea South-East (BSSE) and offshore Jan Mayen (JM), is shown in the column furthest to the right.

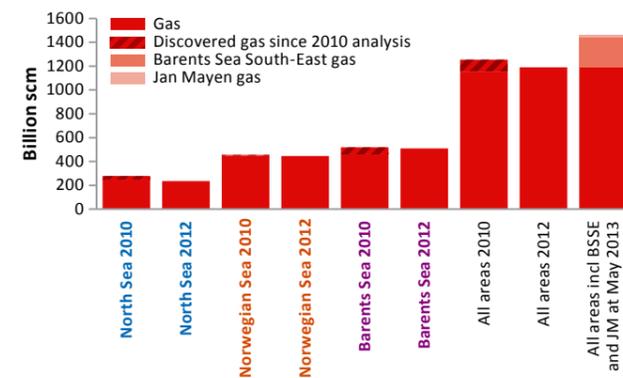


Figure 4.6 Comparison of expected undiscovered recoverable gas resources in the three parts of the NCS and in the total area (2010 and 2012 analyses). The shaded areas indicate how much gas has been found since the 2010 analysis. The potential for the entire NCS, including Barents Sea South-East (BSSE) and offshore Jan Mayen (JM), is shown in the column furthest to the right.

A play is a geographically delineated area where several geological factors are present so that producible petroleum could be proven. These factors are:

- 1) **reservoir rock**: a porous rock where petroleum can accumulate. Reservoir rocks in a specific play will belong to a given stratigraphic level.
- 2) **cap rock**: a tight (impermeable) rock overlying a reservoir rock, so that petroleum can migrate no further and accumulates in the reservoir. The resulting trap must have formed before petroleum ceased to migrate into the reservoir.
- 3) **source rock**: shale, limestone or coal containing organic materials which can be converted into petroleum. The source rock must be mature – in other words, have a temperature and pressure such that petroleum actually forms – and the petroleum must be able to migrate from source rock to reservoir rock.

A play is **confirmed** when producible petroleum is proven in it. This discovery does not have to be commercial. If no producible petroleum has been proven in a play, it is **unconfirmed**.

A **prospect** is a potential petroleum deposit which has yet to be drilled, but which has been mapped and the volume of which can be calculated. The likelihood that a petroleum deposit can be proven in a given prospect is its **probability of success**.

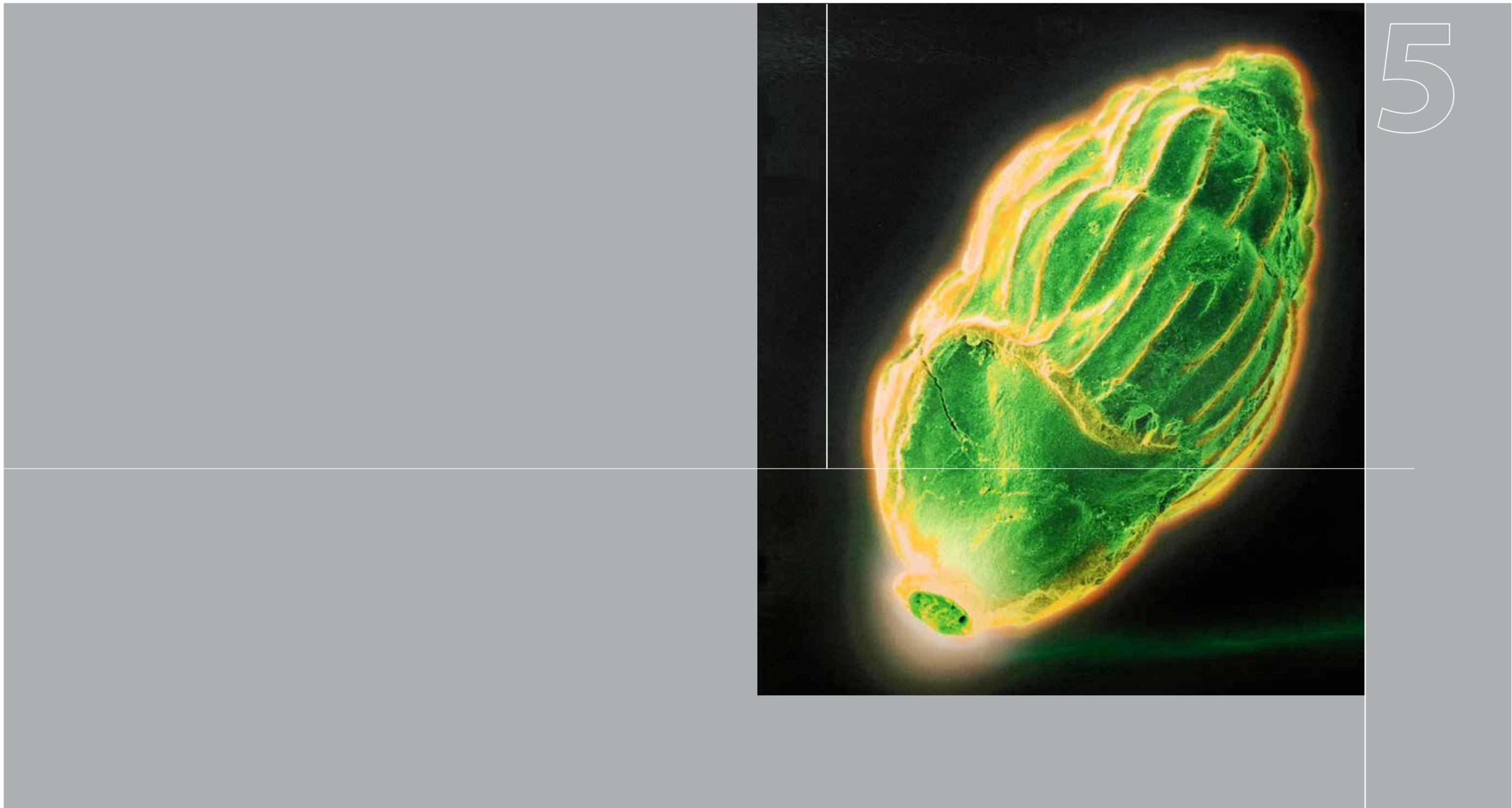
Uncertainty expresses the range of possible outcomes or results. This can be described in many ways, often with the aid of high or low estimates (the NPD estimates, for example, that 0.94-5.42 billion scm oe of oil, gas, condensate and NGL remain to be discovered on the NCS). Uncertainty is usually calculated using statistical methods, such as Monte Carlo simulations. High and low uncertainties can then be described with the aid of statistical concepts. For undiscovered resources, the NPD generally uses P95 for the low estimate. This means that, given the assumptions applied in the analysis, the probability of a result equal to or larger than the P95 value is 95 per cent. P05 is used for the high estimate, which means a five per cent probability that the result will be equal to or larger than the P05 value.

Expected value is the average value. This is generally defined as the arithmetic mean of all the outcomes in the statistical distribution. It is much used, and has the property that the expected value for various distributions can be summed to give a sum of distributions.

Play probability is the estimated probability that producible petroleum can actually be proven in a play. This probability is estimated with the aid of geological mapping and statistical methods. **Prospect probability** is the estimated probability that one or more prospects contain the calculated volume of petroleum, providing the play has been or will be confirmed. **Probability of success** is a product of play and prospect probability. When a play has been confirmed, the probability of success and prospect probability are identical.

An overview of various plays defined by the NPD on the NCS can be found on its website at www.npd.no/en/Topics/Geology/Geological-plays/.

Exploration history and resource growth



5

A creaming curve is a diagram used to present the relationship between aggregated or cumulative resource growth from discoveries and wildcats drilled. Its name probably derives from the fact that the biggest discoveries in an area or a play (the cream of the crop) are normally made early in the exploration history of the area or play. As time passes, remaining prospects will be smaller and have a lower discovery probability.

Such a curve presents the exploration history of an area or play. The X axis is linear, with the number of wildcats in the order of their completion. When a well proves resources in a new discovery, the volume found is plotted as a cumulative value on the Y axis. The result is a rising curve which shows how the area or play has been explored. If the curve is steep, a lot of resources have been found or possibly large discoveries made. A gradual curve indicates that proven discoveries have been small or that many dry wells have been drilled.

Exploration history and resource growth on the NCS

The first well on the NCS, 8/3-1 in the south-eastern part of Norway's North Sea sector, was spudded in 1966. Since then, some 895 wildcats have been drilled and provide the data set for the creaming curve. Wildcats terminated, primarily for technical reasons, before reaching their target are not included.

About 615 wildcats have been drilled in the North Sea, 200 in the Norwegian Sea and roughly 80 in the Barents Sea. The first wildcats in the Norwegian and Barents Sea were spudded in 1980.

The creaming curve shows that discoveries were made after a few wells in all three areas (figure 5.1).

While the first discovery in the North Sea, 25/11-1 Balder, was proven by the second well on the NCS, it took 32 years to bring it on stream. The first big find was made in 1969 with the 27th wildcat, 2/4-2 Ekofisk. This discovery was on stream as early as two years later, when test production began.

The first discovery in the Norwegian Sea, 6507/11-1 Midgard, was proven with the third wildcat in 1981. This forms part of the Åsgard field, which came on stream in 1999.

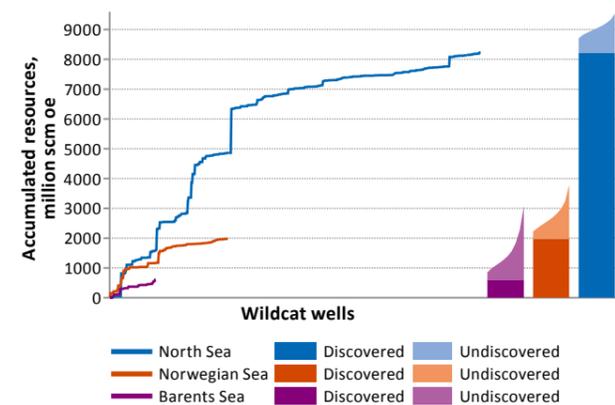


Figure 5.1 Proven and undiscovered resources (light colours) in the North (blue), Norwegian (red) and Barents (purple) Seas. The creaming curve also includes discoveries in resource class 6, which are not included in the resource account.

In the Barents Sea, the first discovery was again made by the third wildcat, 7120/8-1 Askeladd. It came on stream in 2007 as part of the Snøhvit field.

Resources proven in the North Sea are four times greater than those in the Norwegian Sea and 14 times larger than in the Barents Sea. In addition to the creaming curve and proven resources for each area, figure 5.1 presents the uncertainty range for the undiscovered resources. The latter are estimated on the basis of current knowledge about the areas, and the figure will probably change with new information. Based on current knowledge, the combined resources in the Norwegian and Barents Seas will be smaller than those in the North Sea. To provide the most accurate possible exploration history, all discoveries are included in the database – including those in resource category 6 (see the fact box on page 15).

Creaming curves have been developed for each part of the NCS, broken down between liquids and gas, and for individual plays in each area. These plays still have an undiscovered potential, and a number of them have a long exploration history – particularly in the North Sea.

Exploration history and resource growth in the Barents Sea

Some 390 billion scm of gas and 210 million scm of liquids had been proven in the Barents Sea at 31 December 2012 (figure 5.2). The biggest gas discovery is 7121/4-1 Snøhvit in 1984. This includes NGL and condensate as well, which are shown in the curve for liquids. The Snøhvit gas field also comprises four discoveries made prior to 7121/4-1 Snøhvit. These are shown as a small rise in the curve after three wells.

Figure 5.2 shows that possibilities for finding more liquids and gas are considerable. This is illustrated in the columns by the lighter colour shades. A big uncertainty range indicates that knowledge of the Barents Sea remains limited, particularly its northern part. The curves for both liquids and gas show that discoveries have been made in a number of the recent wells. These finds have led to great interest in the area. The plays discussed are illustrated in figure 5.3.

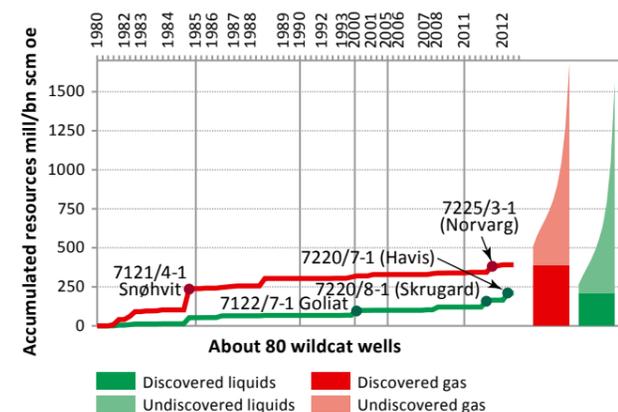


Figure 5.2 Proven and undiscovered (light colours) liquid and gas resources in the Barents Sea.

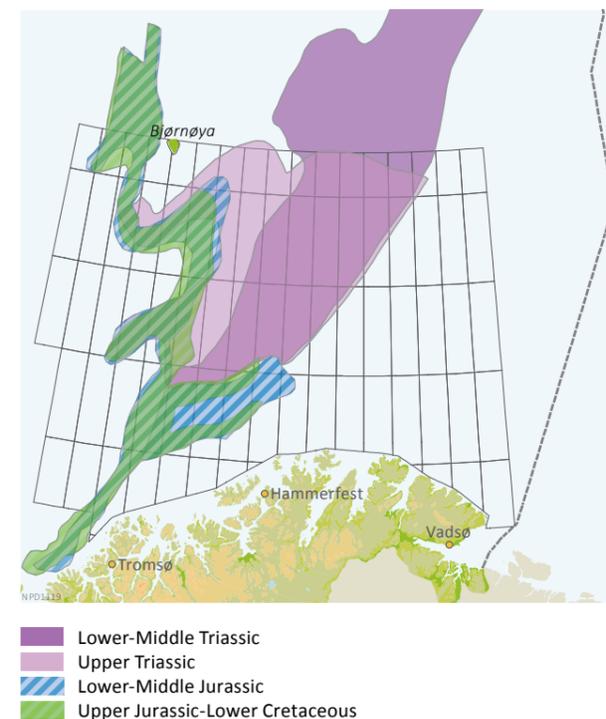


Figure 5.3 Extent of the plays discussed in the Barents Sea.

Upper Triassic to Middle Jurassic play in the Hammerfest Basin

The Upper Triassic to Middle Jurassic play in the Hammerfest Basin is the most thoroughly explored Barents Sea play. This is where the biggest gas discovery, 7121/4-1 Snøhvit, was made. The play also embraces the Goliat oil field, currently under development. Drilling began in this area in 1980. There have been periods with few wells and small discoveries, particularly in the 1990s. Petroleum activities in the Barents Sea were temporarily suspended for a couple of years soon after 2000. The estimate of undiscovered resources shows that the play is still expected to have an interesting potential. See figure 5.4.

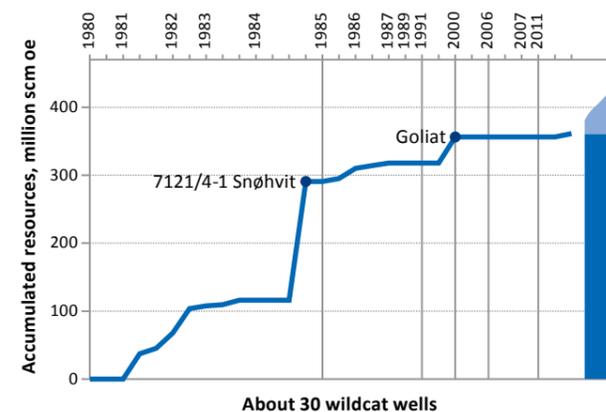


Figure 5.4 Total resources, proven and undiscovered (light blue), in the Upper Triassic to Middle Jurassic play in the Hammerfest Basin.

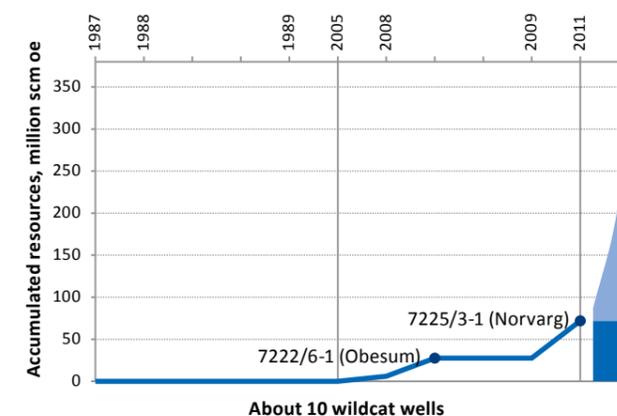


Figure 5.5 Total resources, proven and undiscovered (light blue), in the Lower to Upper Triassic play on the Bjarmeland Platform.

Lower to Upper Triassic play on the Bjarmeland Platform

Little exploration has taken place in the Lower to Upper Triassic play on the Bjarmeland Platform. Some 10 wildcats have been drilled and three gas discoveries made, with 7225/3-1 (Norvarg) as the largest. See figure 5.5. The first well to test the play was drilled in 1987, and the next five were dry. An appraisal well is to be drilled on the 7225/3-1 discovery this year. After a couple of discoveries which were significantly smaller than expected, 7225/3-1 (Norvarg) is encouraging, and the estimate of undiscovered resources shows that the potential remains large.

Upper Triassic to Lower Cretaceous plays along the Ringvassøya-Loppa and Bjørnøyrenne fault complex

The Upper Triassic to Lower Cretaceous plays along the Ringvassøya-Loppa and Bjørnøyrenne fault complex are relatively unexplored, with about 16 wildcats. More than half of these were dry. See figure 5.6. The first well in these plays was drilled in 1983, and the first discovery there – the 7019/1-1 gas find – lies right at their southern end. Finding oil in Johan Castberg (7220/8-1 Skrugard and 7220/7-1 Havis) has prompted a new view of the plays, and interest in exploring them is great. The estimate for undiscovered resources shows that the potential remains large.

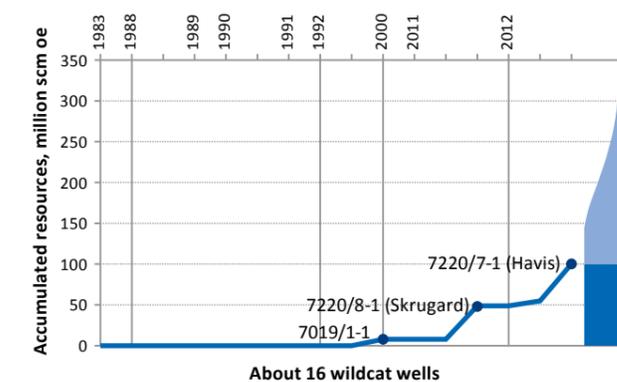


Figure 5.6 Total resources, proven and undiscovered (light blue), in the Upper Triassic to Lower Cretaceous plays along the Ringvassøya-Loppa and Bjørnøyrenne fault complex.

Exploration history and resource growth in the Norwegian Sea

Some 1 000 billion scm of gas and 975 million scm of liquids had been proven in the Norwegian Sea at 31 December 2012. See figure 5.7. Ormen Lange is the biggest gas discovery. The creaming curve shows that the first discovery wells found mainly gas as well as a good deal of oil. In an early phase of its exploration history, the Norwegian Sea was considered to be a gas province. The discovery of Draugen changed that assessment. Wells up to Norne proved relatively large liquid resources, but the curve subsequently shows smaller growth. Ormen Lange caused the curves for liquids and gas to move closer together, following about 12 years of exploration drilling which largely discovered liquids. The most recent wildcats, roughly 30 in all, have largely proven gas, so that the gas curve lies a little above that for liquids. The estimate of undiscovered resources shows that the upside potential for gas is considered to be rather larger than for liquids, that uncertainty is high but lower than in the Barents Sea, and that the potential remains large. The plays discussed are presented in figure 5.8.

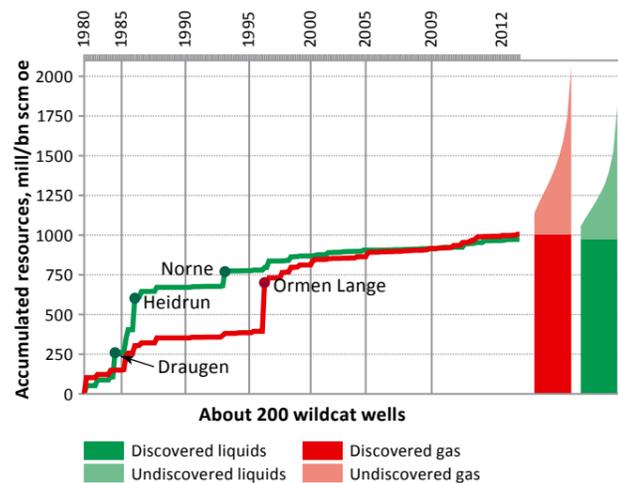


Figure 5.7 Proven and undiscovered (light colours) liquid and gas resources in the Norwegian Sea.

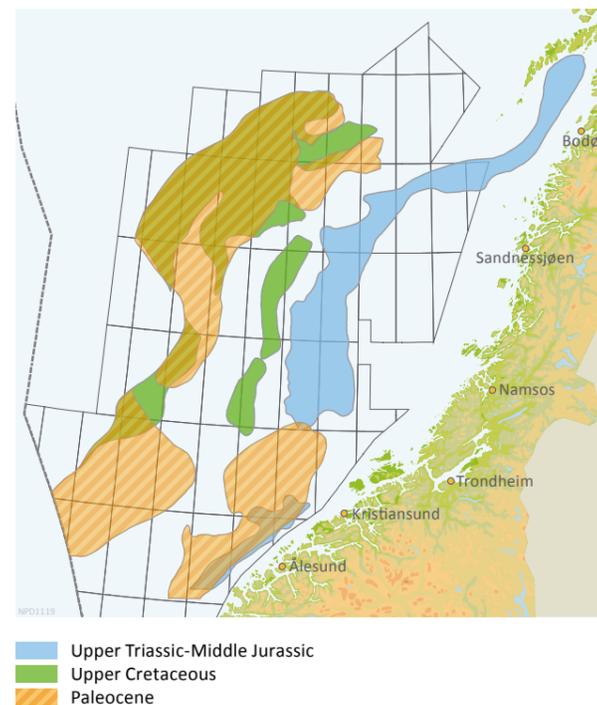


Figure 5.8 Extent of the plays discussed in the Norwegian Sea.

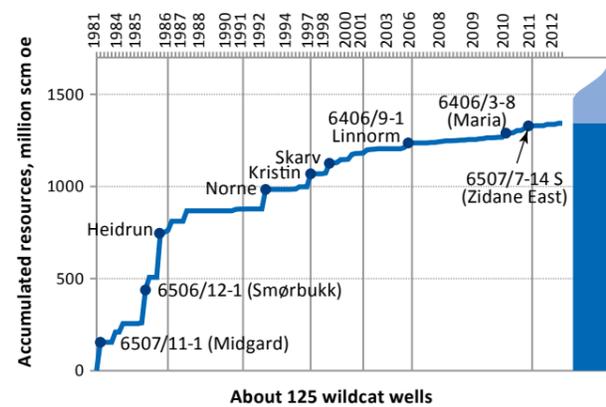


Figure 5.9 Total resources, proven and undiscovered (light blue), in the Upper Triassic to Middle Jurassic play on the Halten Terrace-Nordland Ridge.

Upper Triassic to Middle Jurassic play on the Halten Terrace-Nordland Ridge

The creaming curve for the Upper Triassic to Middle Jurassic play on the Halten Terrace-Nordland Ridge and nearby structural elements shows that this is the best explored and most successful play in the Norwegian Sea so far. See figure 5.9. Exploration began in 1981, and the 6507/11-1 Midgard discovery was made after a few wells. With the exception of the Draugen oil field and the Ormen Lange gas field, all the largest discoveries in the Norwegian Sea have been made in this play. Finds since 2000 have been relatively small, but the play is still considered to have a substantial potential.

Upper Cretaceous to Upper Palaeocene plays in deep water

The Upper Cretaceous to Upper Palaeocene plays in deepwater areas of the Norwegian Sea have been explored since 1997, with Ormen Lange as the biggest discovery so far. See figure 5.10. The first gas find is 6707/10-1 (Luva), which has been sanctioned for development together with several smaller discoveries as part of the Aasta Hansteen development. These discoveries are illustrated as a slight rise in the creaming curve between 2008 and 2009. The most recent deepwater well was drilled in 2011, and no wells are planned for 2013. Expectations for these plays were great when exploration began in 1997, but results so far have been less encouraging. However, the play still has a large potential.

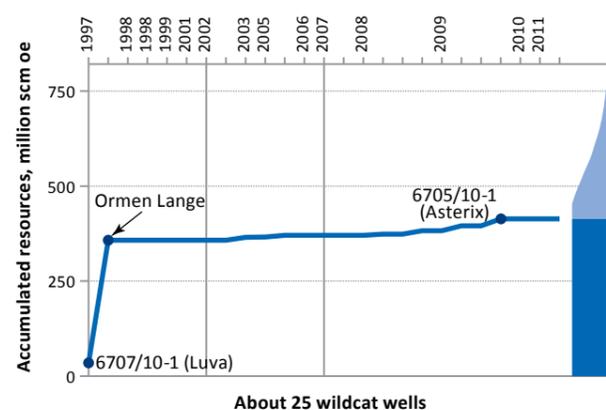


Figure 5.10 Total resources, proven and undiscovered (light blue), in the Upper Cretaceous to Upper Palaeocene plays in deep water.

Exploration history and resource growth in the North Sea

Some 3 000 billion scm of gas and 5 100 million scm of liquids had been proven in the North Sea at 31 December 2012. See figure 5.11. Statfjord and Ekofisk are the biggest oil fields, and by far the largest gas field is Troll East. After Grane was discovered in 1991, the curve for liquids rose weakly until 16/2-6 Johan Sverdrup was found in 2010. The curve for gas shows a weak rise after the discovery of Kvitebjørn in 1994. The estimate for undiscovered resources in the North Sea is less uncertain than for the Norwegian and Barents Seas because this area has been more thoroughly explored. Over three times as many wildcats have been drilled there than in the Norwegian Sea, and about eight times more than in the Barents Sea. Opportunities for making interesting discoveries in the North Sea are still present. The plays discussed are presented in figure 5.12.

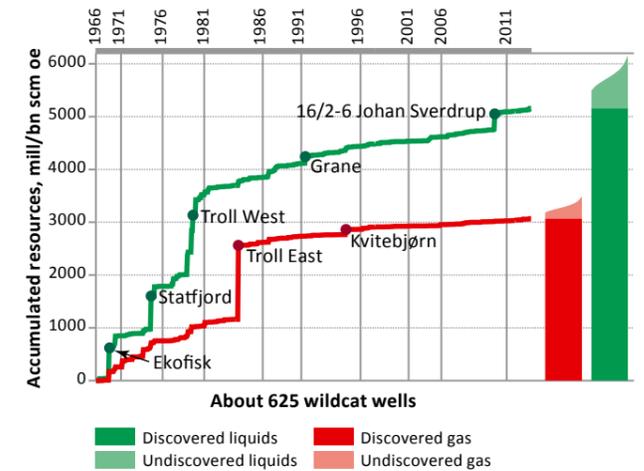


Figure 5.11 Proven and undiscovered (light colours) liquid and gas resources in the North Sea.

Upper Triassic to Middle Jurassic play in the central and northern North Sea sector

The Upper Triassic to Middle Jurassic play in the central and northern areas of Norway's North Sea sector is the best explored on the NCS, and many of the biggest finds lie there. Most of these are on the Tampen Spur. The biggest discoveries were proven before 1980, and no large finds have been made in this play since Kvitebjørn in 1994. See figure 5.13. However, small discoveries are frequently proven, which is illustrated in the curve by a steady rise. One of the largest finds since 2010 is 35/9-6 (Titan). Although very considerable resources have been proven in this play, it still has a significant potential.

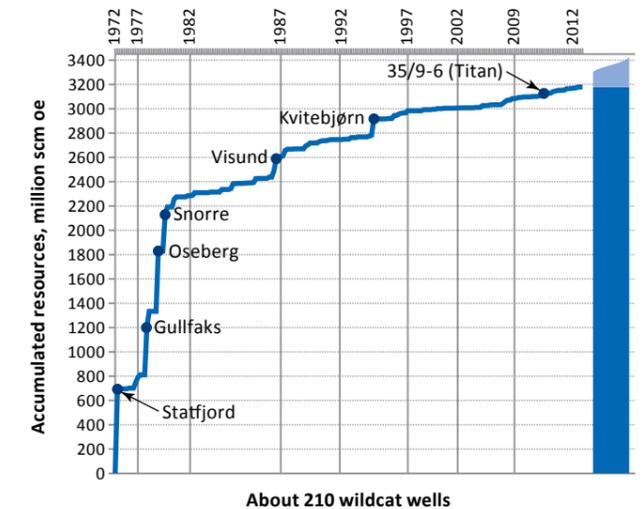


Figure 5.13 Total resources, proven and undiscovered (light blue), in the Upper Triassic to Middle Jurassic play in the central and northern North Sea sector.

Upper Jurassic play in the northern North Sea sector

The Upper Jurassic play in the northern part of Norway's North Sea sector contains the Troll field, as shown in figure 5.14. This giant find means that the other discoveries in the play barely show up on the curve when Troll is included. A creaming curve has accordingly also been produced without Troll. See figure 5.15. The curves show that relatively few discoveries have been made or resources proven when Troll is excluded. Few wells were drilled in the five-year periods 1975-79, 1986-90, 1991-95 and 2003-07. Since 2007, exploration activity has revived, and the 35/9-7 (Skarfjell) discovery was proven in 2012. This play retains an interesting potential for undiscovered resources.

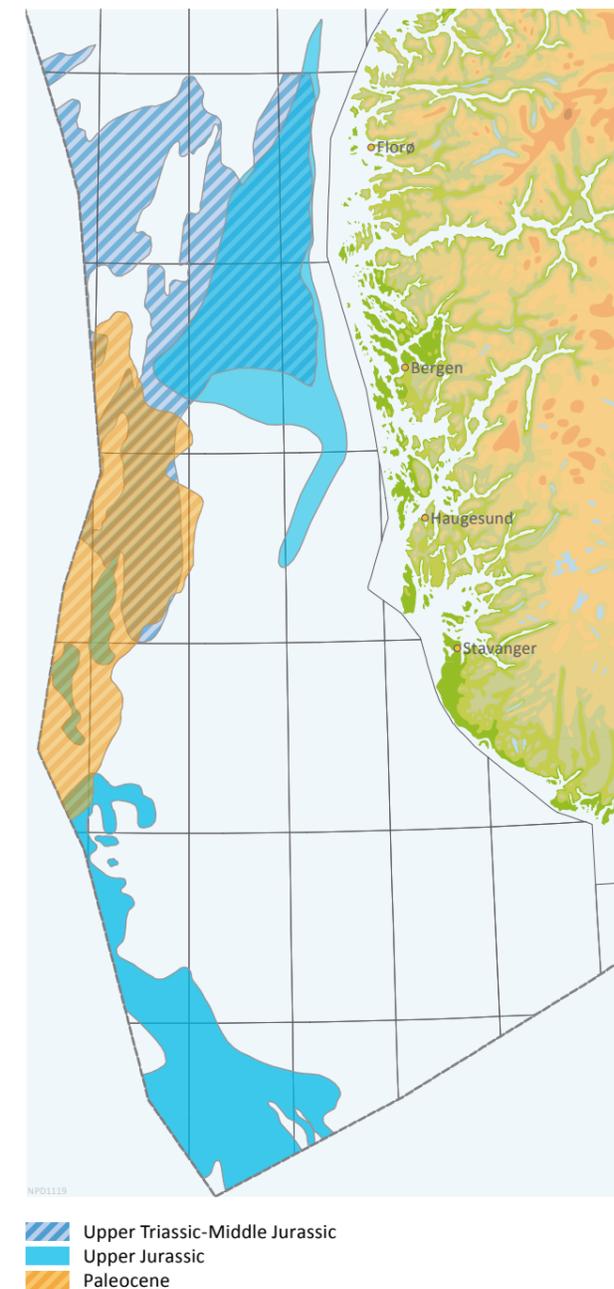


Figure 5.12 The extent of the plays discussed in the North Sea.

Upper Jurassic play in the southern North Sea

The Upper Jurassic play in the southern part of Norway's North Sea sector has a long exploration history. See figure 5.16. Discovered in 1976, the Ula oil field came on stream in 1986. The creaming curve shows that relatively few resources were found from the discovery of Tambar in 1983 to 8/10-4 S (Butch) in 2011 and 2/4-21 (King Lear) in 2012. This play is still expected to have a substantial potential.

Palaeocene play in the central North Sea sector

The Palaeocene play in the central part of Norway's North Sea sector has a long exploration history. See figure 5.17. Since the Balder

oil field was proven in 1967, about 100 wildcats have been drilled in the play. Relatively few resources were found between the discovery of Jotun in 1994 and the Alvheim find in 1998. Four discoveries were made in 2003, of which 25/4-7 (Kneler) and 24/6-4 (Boa) are part of the Alvheim field. The other two are 16/6-1 (Verdandi) and the 25/4-9 S Vilje oil field. A discovery was also made in production well 25/8-C-20 on Balder. Proven in 2008, 25/11-25 Svalin is now under development. Some 10 wildcats have been drilled since 2008, but with few resources proven. The potential for finding more is present.

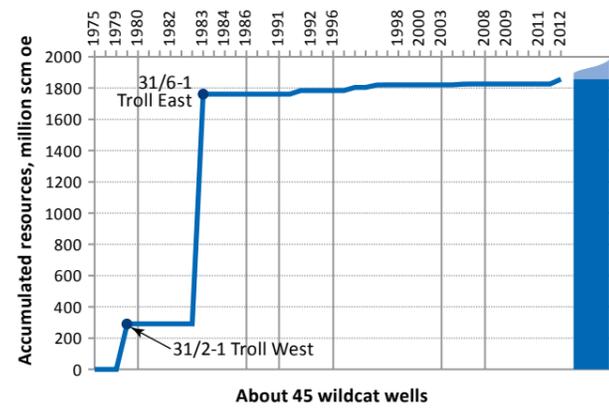


Figure 5.14 Total resources, proven and undiscovered (light blue), in the Upper Jurassic play in the northern North Sea sector.

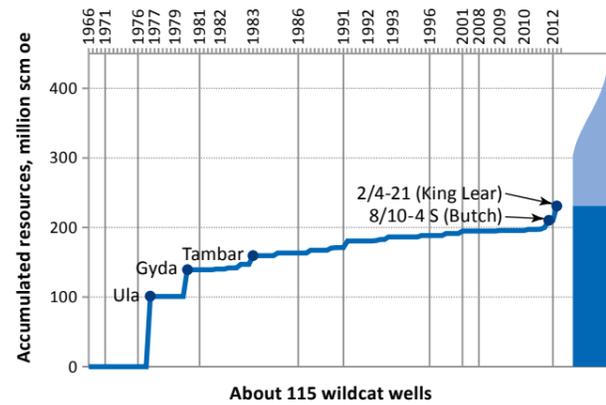


Figure 5.16 Total resources, proven and undiscovered (light blue), in the Upper Jurassic play in the southern North Sea sector.

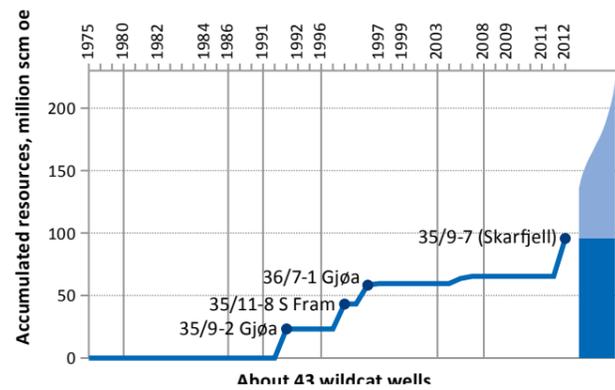


Figure 5.15 Total resources, proven and undiscovered (light blue), in the Upper Jurassic play in the northern North Sea sector after excluding Troll.

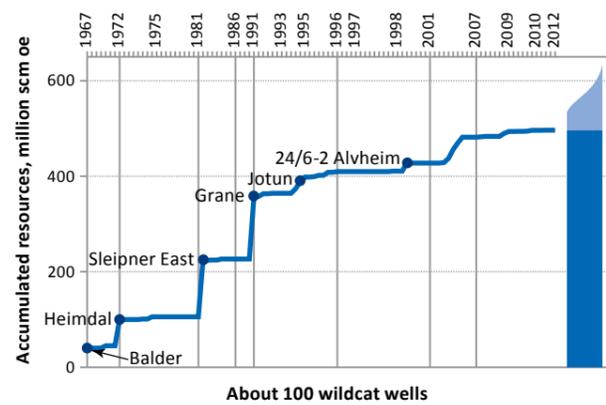
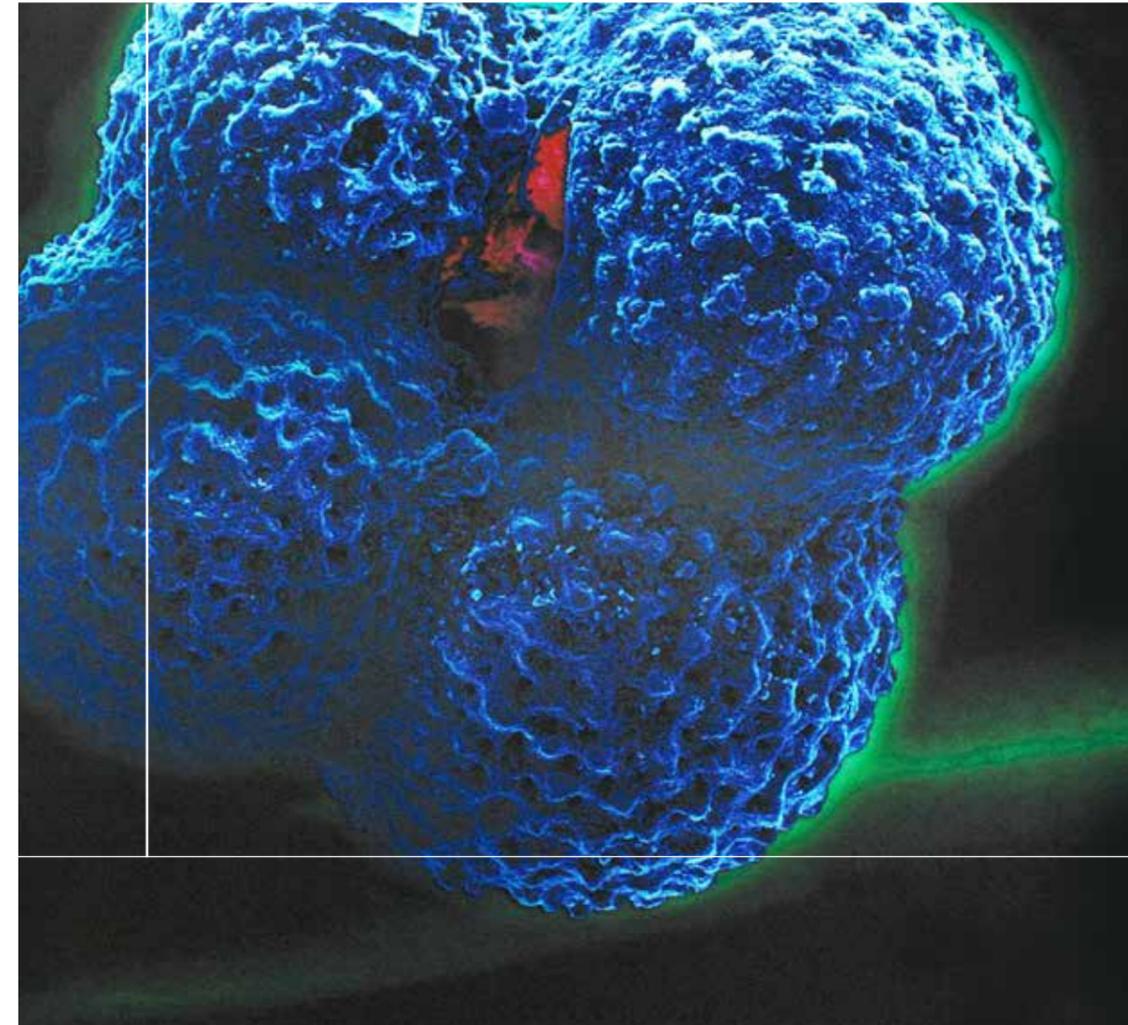


Figure 5.17 Total resources, proven and undiscovered (light blue), in the Palaeocene play in the central North Sea sector.

Barents Sea South-East



After the treaty with Russia on maritime delimitation and collaboration in the Barents Sea and the Arctic Ocean came into force on 7 July 2011, work began on a process to open Barents Sea South-East for petroleum activities.

The sea area covered by this process embraces some 44 000 square kilometres. It extends north to 74°30'N, is bounded by the Russian sector to the east, and is delineated in the west by the opened area of Barents Sea South. See the map in figure 6.1. This area is almost as large as Finnmark county.

An opening process is intended to provide the technical facts on which the Storting can base a decision. As part of this work, the NPD has mapped the geology of the area and estimated its resource potential. The principal results of this mapping were published in February 2013 and are presented in White Paper 36 (2012-2013) concerning new opportunities for northern Norway – opening Barents Sea South-East for petroleum activities.

This chapter provides a more detailed technical review of the geology and the results of the geological mapping than has been published earlier. It also presents the NPD's estimate of undiscovered resources in the area.

Data

Geological knowledge of Barents Sea South-East is relatively limited. No shallow scientific or exploration drilling has so far taken place there. On the other hand, a number of wells have been drilled in the open part of Barents Sea South. Some published data are also available from commercial drilling in the Russian sector of the Barents Sea. Wells in other parts of the Barents Sea provide relevant information (well logs, dating, core measurements and calibration of seismic data) which is crucial for understanding the petroleum system and reservoir properties in Barents Sea South-East.

Two-dimensional seismic data was acquired by the NPD during 1974-82 in the boundary area with the Russian sector where the two countries had overlapping interests. The quality of these data is very variable, and the data coverage low and unsystematic. No seismic surveys were conducted by the Norwegian authorities from 1982 until the maritime delimitation treaty between Norway and Russia came into force.

The new seismic data package comprises two 2D seismic datasets acquired during the summer seasons of 2011 (about 11 500 kilometres) and 2012 (about 6 800 kilometres), as shown in figure 6.2.

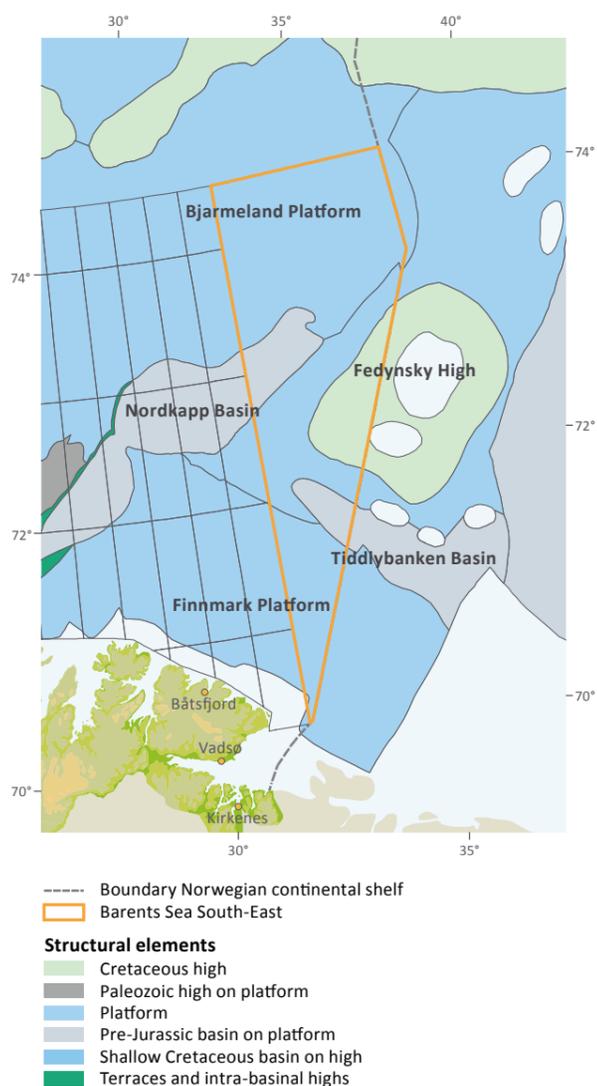


Figure 6.1 The Barents Sea South-East area and the most important section of the sedimentary succession in this area from a petroleum perspective.

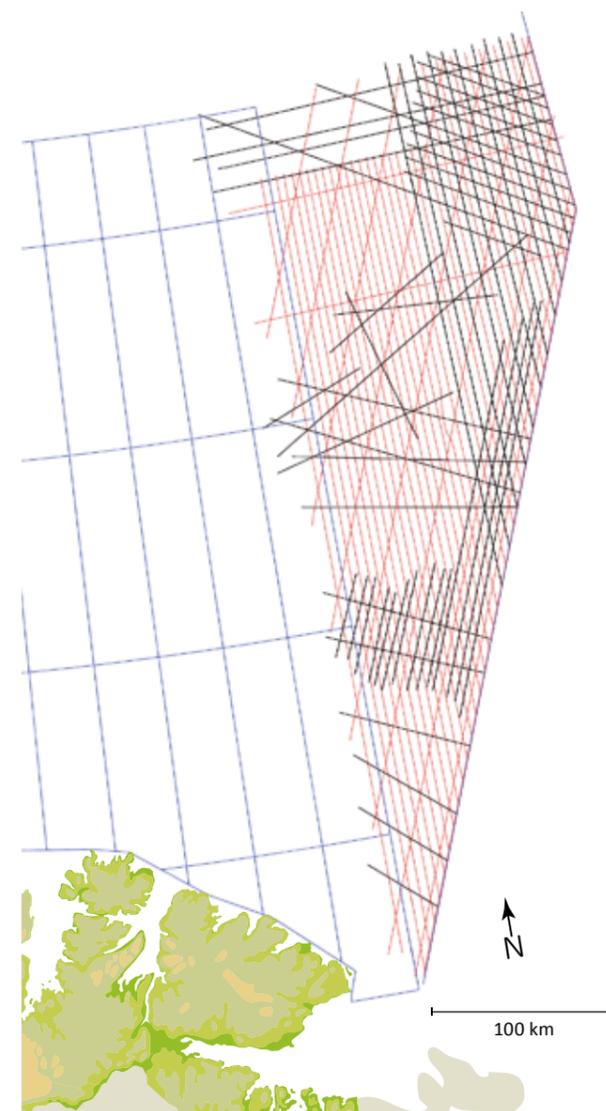
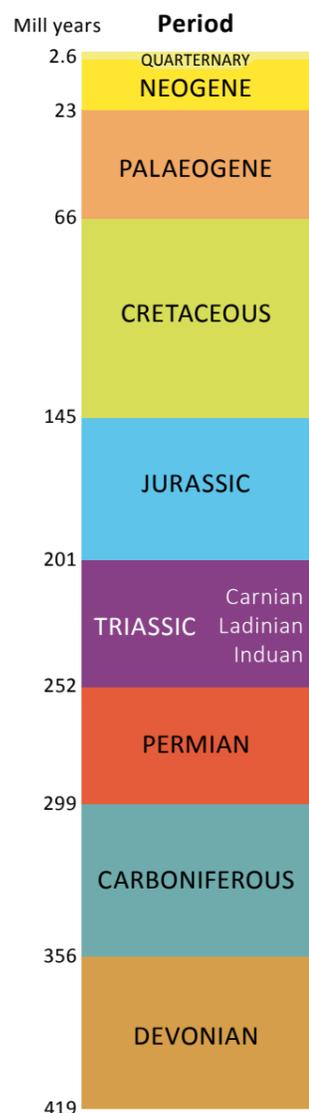


Figure 6.2 2D seismic data acquired in 2011 (red) and 2012 (black) in the Barents Sea.

GeoStreamer technology was used in the 2011 survey. This means that the hydrophone streamer is towed at a greater depth in the water than with conventional seismic surveys. The operation can thereby cope with higher waves, is less weather-dependent and consequently more efficient. Conventional 2D methods were used in 2012.

Emphasis was given during the 2011 and 2012 surveys to systematic acquisition with long lines covering the whole of the new area up to 74°30'N. A grid measuring roughly 5x20 kilometres was established in 2011 in order to obtain an overview of geology in an unknown area. Supplementary seismic data were acquired in 2012, with particular emphasis on the most interesting areas.

Gravimetric and magnetometric data were acquired alongside the seismic surveys in 2011 and 2012. This information could help to improve understanding of the deeper structuring.

Processing all the seismic data acquired in 2012 was completed during November/early December of that year. Relatively shallow waters, a hard seabed and a very marked reflector from the Lower Cretaceous made processing a demanding business, but the NPD considers the quality of both raw data and processing to be satisfactory.

Main structural features of the area

Five large regional geological elements define the structural picture in Barents Sea South-East. See figure 6.3. At the southern end of the area, the Finnmark Platform abuts the Norwegian coast with strata generally dipping northwards. In the north, the eastern section of the Bjarmeland Platform extends into the new areas. Strata here generally dip southwards. Between the two platforms, the Nordkapp Basin has developed as a deep Carboniferous/Permian subsidence basin where large quantities of salt have been deposited. The Tiddlybanken Basin forms a corresponding salt basin to the south-east. Both basins have been subject to intensive salt movement through the Triassic and up into the Palaeogene. The fifth large structural element in the region is the Fedynsky High, most of which lies in the Russian sector.

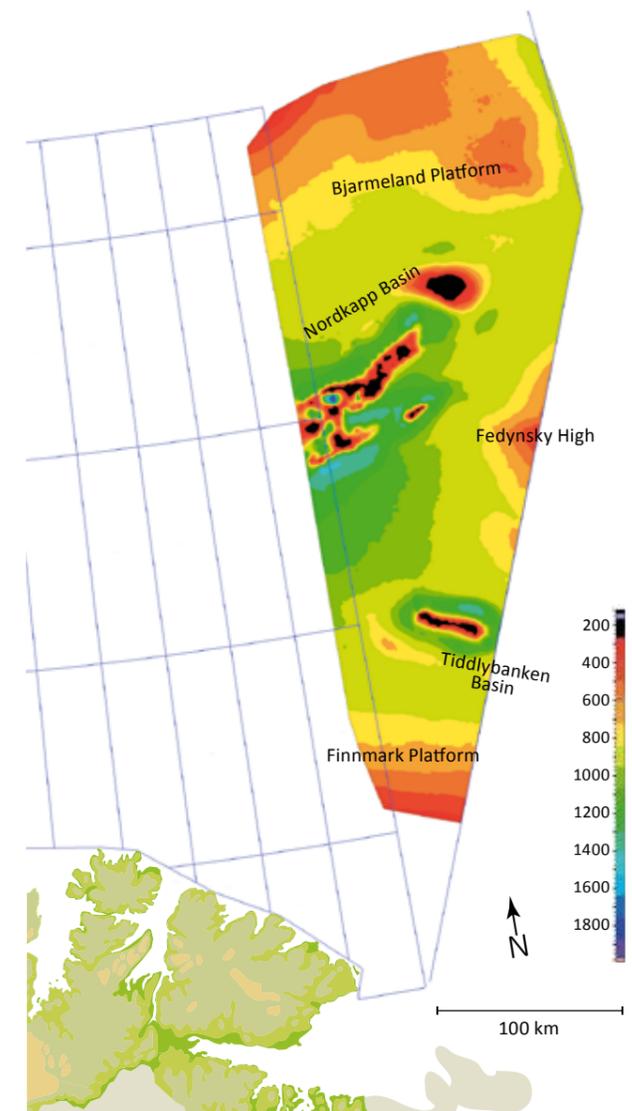


Figure 6.3 Timeline map from the base of the Cretaceous showing the most important structural elements in the geology of Barents Sea South-East.

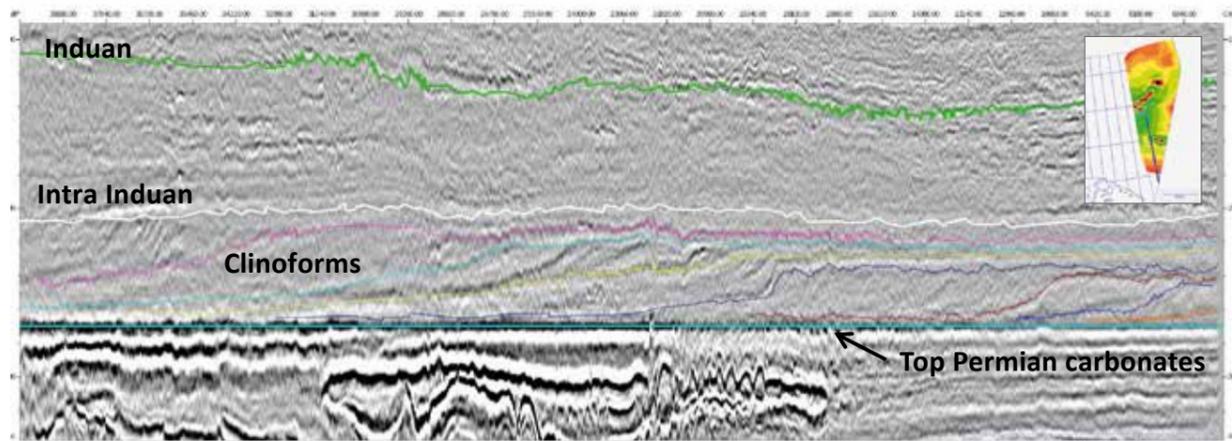


Figure 6.4 Seismic line showing the development of a delta (clinoforms) in the Lower Triassic. The line is flattened atop a Permian limestone reflector. Its position is shown in the inset map.

Finnmark Platform

The Finnmark Platform covers a large area extending from west Finnmark along the Varanger Peninsula and into the Russian sector. From the seismic data, Lower Carboniferous deposits appear to lie directly on the basement in many parts of the new areas on the Finnmark Platform. Little basis exists at present for saying that Devonian basins have developed under the Carboniferous sediments in the new areas on the Finnmark Platform. But the presence of some small sedimentary basins older than the Carboniferous cannot be excluded.

The Finnmark Platform is perhaps best known for its shallow marine limestones and dolomites with reef structures in the shape of carbonate and sponge (spiculite) reefs. These limestones formed in the Carboniferous and Permian. Towards the end of the Permian, the carbonate rocks were covered by the sea. This event forms a good seismic reflector which can be followed over long distances. During a brief period, the sea over the Finnmark Platform deepened before the development of a large delta began to fill the whole Barents Sea. That started at the boundary between the Permian and the Triassic. Close to the coast in the new areas, the traces of this deposition are clearly visible in the seismic images as clinoforms from the Lower Triassic, as shown in figure 6.4.

A large structure has developed at the boundary between the northern Finnmark Platform and the Tiddlybanken Basin. See figure 6.3. This structure has a small pillow of salt or anhydrite at its core. The Triassic and Jurassic sedimentary successions in this structure have not been eroded during the Palaeogene or Quaternary, so that the most important reservoir rocks are assumed to be intact there.

Nordkapp and Tiddlybanken Basins

The Nordkapp and Tiddlybanken Basins are two marked subsidence basins located north-west and north-east respectively of the Finnmark Platform. Their axes run at an angle of almost 90 degrees to each other. The characteristic feature of both basins is the formation of large quantities of salt during the Carboniferous and Permian. This salt initially lay largely undisturbed after its deposition. As delta development during the Lower Triassic reached the respective basins, the load on the salt deposits became so high that the salt began to move upwards through the sedimentary succession because its specific gravity was lower than the surrounding sediments in the basin. See figure 6.5. These salt movements occurred in several rounds during the Triassic and Palaeogene. As a result, the salt today forms large, almost vertical salt diapirs.

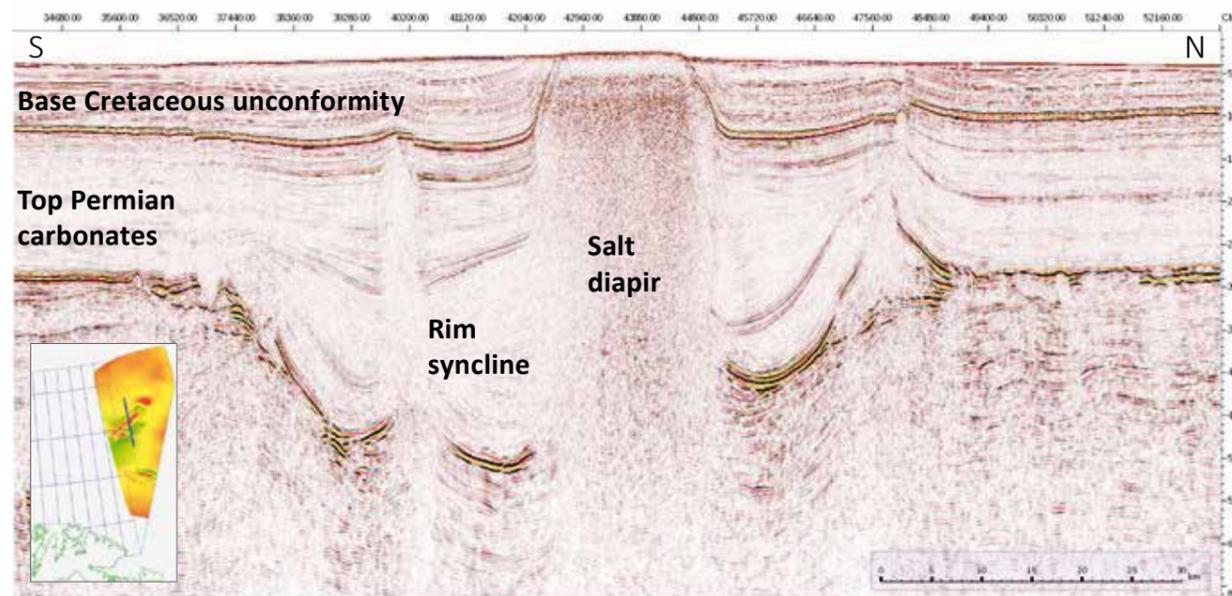


Figure 6.5 Seismic line through the Nordkapp Basin showing the development of salt diapirs and rim synclines in the Triassic. Its position is shown on the inset map.

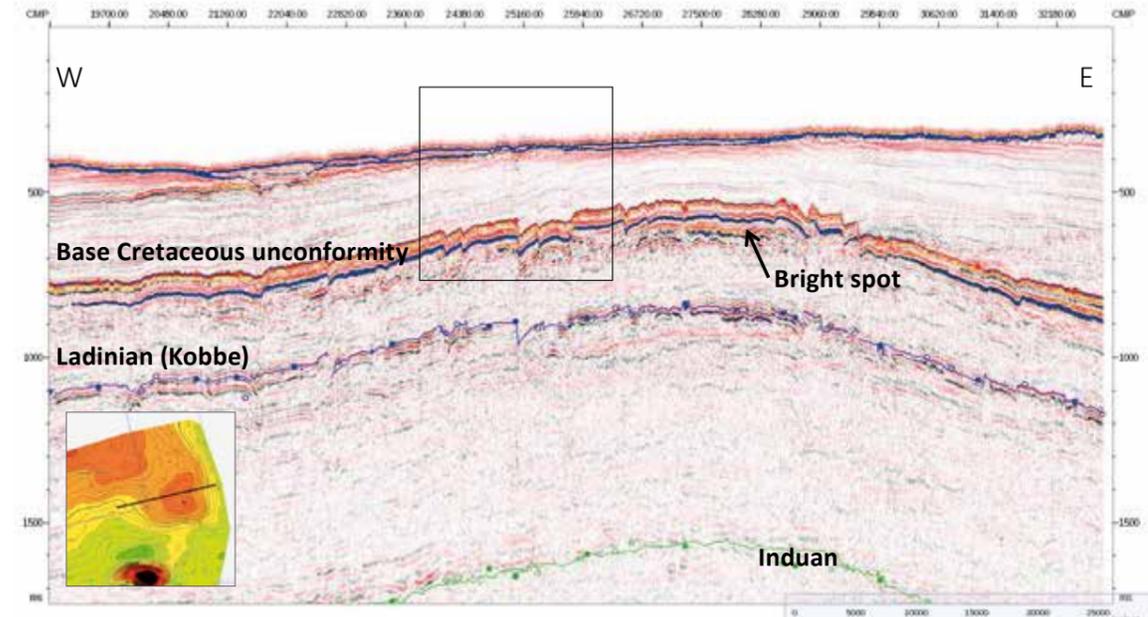


Figure 6.6 Large structure in the northern part of Barents Sea South-East. The position is shown on the inset map.

Most of these extend up to the seabed. Rim synclines formed in the areas around the salt structures with thicker layers of Triassic sediments and heavy erosion from time to time of the strata closest to the salt structures. A very large salt diapir has formed in the Tiddlybanken Basin on the Norwegian side of the boundary, with a well-developed rim syncline around the salt plug, as shown in figure 6.3. A seismic line along the salt diapir suggest that it has two domes. The bulk of the sediment in the rim synclines derives from the river systems and delta development in the east and south-east, which flowed around the salt structures.

A large salt structure has developed in the north-easternmost part of the Nordkapp Basin (see figure 6.3), where the base-Cretaceous reflector is eroded but where sediments in the Lower and Middle Triassic have been preserved. This structure could have a potential to contain oil or gas in the Middle Triassic.

With many of the salt structures, the seabed is higher than the areas surrounding the structures and forms a positive relief. This is clear over the Tiddlybanken Basin and several of the structures in the Nordkapp Basin. Seismic data show that the salt could have drawn limestones with it up to the seabed, which have laid themselves over the salt structure, and that erosion during the Quaternary removed the softer surrounding sediments. This could have prevented the salt from flowing out into the sea. An alternative is that the salt remains active, and forms a structural relief as it rises towards the seabed. The relief could be a combination of these two models.

Bjarmeland Platform

The Bjarmeland Platform covers large parts of the central Barents Sea. It is characterised by relatively few structures, but certain large ones could be important as oil and gas traps. In many cases, a pillow of salt at the base of these large structures controls structuring in the Palaeogene. A good example of such large structures is the Norvarg Dome, where gas has been found in several intervals from the Triassic to the Jurassic.

The Bjarmeland Platform extends into the northern part of Barents Sea South-East, where a large structure has developed which appears from the seismic images to have retained a more or less intact sedimentary succession from the Permian to the Upper Jurassic. See figure 6.6. This structure rests on a pillow of Car-

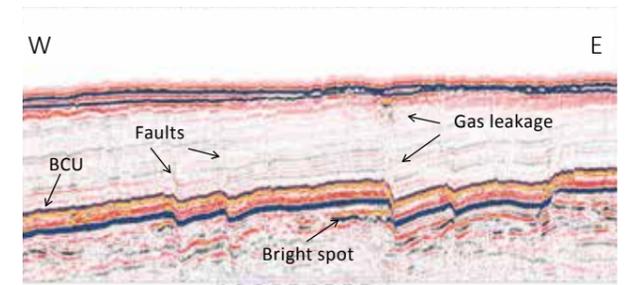


Figure 6.7 Gas leakage from a bright spot in the Upper Jurassic (section of figure 6.6).

boniferous/Permian salt. A series of small Palaeogene faults have developed in the structure, which affect the structures at Triassic, Jurassic and Cretaceous levels. A number of these faults extend right up to the seabed. Seismic amplitude anomalies on some of these faults indicate that gas is probably leaking from gas reservoirs in the Realgrunnen sub-group. See figure 6.7.

Fedynsky High

The flank of the Fedynsky High lies in the eastern part of the new areas, with its bulk on the Russian side. New seismic data show that it has a complex geological history. A deep graben cuts into the Carboniferous/Permian on the Norwegian side. This basin is later inverted, and currently forms the highest point of the Fedynsky High in the Norwegian sector. See figure 6.8. The continuation into the Russian sector is unknown because access to data is lacking. The basement probably stands high up on both sides of this basin and gives rise to gravitational and magnetic anomalies on the Fedynsky High. Running in the same direction as the Tiddlybanken Basin, the basin extends west to the Nordkapp Basin. Mappable quantities of salt have developed in this basin, but not sufficient to form salt diapirs.

It is already known that the top of the Fedynsky High has been heavily eroded in the Russian sector. The new seismic data confirm that virtually the whole sedimentary package above the base of the Cretaceous has been eroded away on the Norwegian side. Old published maps from the Russian sector show that the erosion descends deep into the Triassic there.

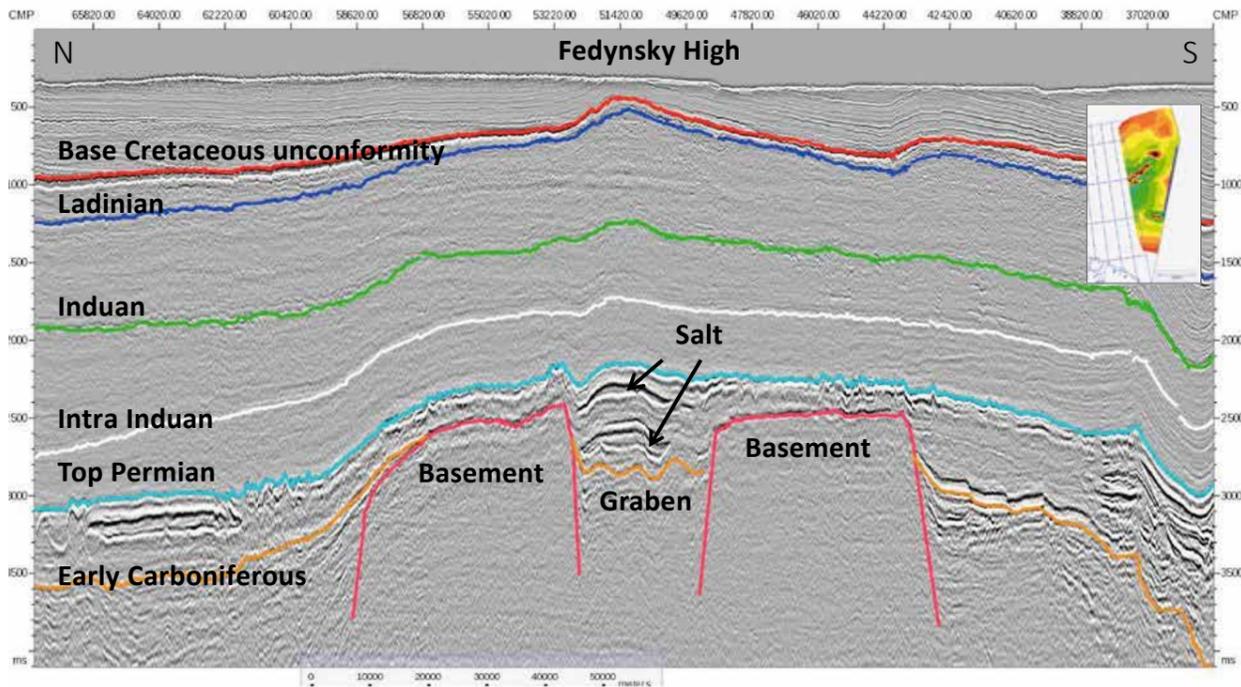


Figure 6.8 Seismic line from the flank of the Fedynsky High, which shows that a Carboniferous/Permian graben structure with salt deposits underlies its highest part on the Norwegian side. The position is shown in the inset map.

Reservoir rocks

Several important factors govern the formation of reservoir rocks in Barents Sea South-East. The original deposition environment is important for reservoir properties and, because the area is large and stretches a long way, this will vary between the different areas at one and the same time. When fluvial sediments with channel sandstones were forming in the south, more continuous shallow marine sandstones may have developed to the north. Limestones and sponge reefs have formed in other epochs, and could have given rise to reservoir rocks.

The common denominator of all the reservoirs is that burial depth is an important factor governing their properties over time. At shallow depths, the reservoirs will have good properties, as in well 7131/4-1 (Guovca) on the Finnmark Platform. If the reservoir is buried too deep, porosity and permeability – and thereby flow properties for oil and gas – will eventually deteriorate. Ultimately, these properties will be so reduced that the rock can no longer be regarded as suitable for a reservoir.

Rocks in the new areas have been uplifted by 1 000-1 500 metres. When estimating reservoir properties, changes will be governed particularly over time by the maximum depth of burial and temperature. Middle and Upper Triassic and Jurassic reservoirs in the relevant areas will lie at an acceptable depth, where it is reasonable to assume that their properties have been preserved. At deeper Lower Triassic and Carboniferous/Permian levels, reservoir properties may primarily have been preserved in areas close to the coast where these rocks have not been buried too deeply. In some formations, a secondary growth of chlorite has occurred which may prevent quartz overgrowth in the rock pores and preserve relatively good porosity down to greater-than-normal depths.

One of the biggest challenges in the central parts of the Barents Sea is the sealing potential. That applies particularly to possible Jurassic reservoirs. Uplift in the Barents Sea and the accumulation

of salt in the cores of most structures have caused intense fracturing and the development of small faults in and above the structures. These extend in many places right up to the surface or halt at unconsolidated Quaternary deposits. Seismic data indicate that gas is leaking from the Jurassic reservoirs in some structures. This shows that gas has formed in the area. The question is how much gas remains in the reservoirs and whether oil can be found.

Maps from the Mareano project mapping the bed of Barents Sea South-East, which are available on Mareano's website at www.mareano.no, show the presence of a great many pockmarks across large parts of the area already mapped. Such pockmarks are formed in unconsolidated seabed sediments by the expulsion of water or escape of gas. Their regular distribution over large areas may indicate that they are caused by water expulsion or the escape of biogenic gas. Should the leakage relate to the escape of gas from older reservoir rocks, this observation could reduce the gas potential in the southern part of Barents Sea South-East.

Carboniferous/Permian

Carboniferous/Permian rocks lie too deep or have been too deeply buried across most of the new areas to be relevant as reservoir rocks. The exception is a small area close to the Norwegian coast, where these rocks extend right up to the seabed. Gas accumulations could be possible here in Lower Carboniferous sandstones. Possible traps will be stratigraphic or structural, but few faults exist to serve as traps close to the Norwegian coast. Possible Carboniferous and Permian prospects could exist in limestone and sponge reefs. The 2D seismic data are not sufficient to map this type of reservoir with any degree of detail. The area is limited in size, with the reef structures between one and 1.5 kilometres wide and their longitudinal extent unknown. Experience from wells 7228/7-1 A in the Nordkapp Basin and 7128/4-1 on the Finnmark Platform further to the west show that both oil and gas could be present in possible prospects, but the quantity is uncertain.

Lower Triassic

Seismic data show that the continental shelf has been extended in the Lower Triassic from east and south-east to west and north-west. During this process, shallow marine sediments could well have been deposited to provide the basis for sandstone formation. These are generally deeply buried, so that reservoir properties will be reduced across large areas. The number of structural traps is limited, but Lower Triassic reservoirs are the most relevant in the southern part of the new areas in particular.

Middle and Upper Triassic

Middle and Upper Triassic reservoirs have the biggest potential for containing oil or gas in Barents Sea South-East. Generally speaking, these possible reservoirs lie at a depth where their properties remain intact. At the same time, the retention potential is greater than higher up in the Jurassic, where gas is leaking from the structures.

The seismic data show that large parts of the sedimentary succession in the Middle and Upper Triassic appear to comprise delta plain deposition with channels which have flooded over the fluvial plain. The seismic signals are more continuous in the northern part. This might suggest that opportunities for finding continuous Middle Triassic marine sandstones are greater in this area. Both marine shales and shallow marine tidal deposits have been proven in shallow scientific boreholes on the Sentralbanken High. This increases the likelihood that marine sandstones also exist in the northern part of Barents Sea South-East. Small faults help to break up the reservoirs.

Upper Triassic channel sandstones with very good reservoir properties have been proven in well 7131/4-1 on the Finnmark Platform. This was drilled in a stratigraphic trap which proved to be dry. Where a source in the Tiddlybanken Basin is concerned, the well has been drilled in the shadow of the large structure separating this basin from the Finnmark Platform. That structure may have captured all the petroleum which could have migrated from the Tiddlybanken Basin.

The probability of finding gas in the Middle and Upper Jurassic is highest in the north, while gas and oil are more likely close to the salt basins in the south.

Middle Jurassic

Knowledge acquired from wells in the Barents Sea farther to the west shows that Middle Jurassic reservoir sandstones with good properties could be present in the new areas. Seismic amplitude anomalies suggest that gas pockets have been preserved in a number of the structures, but the seismic data also show that these reservoirs are leaking gas because of heavy fracturing caused by salt tectonics and a tight network of small faults. The retention potential in the Middle Jurassic is accordingly regarded as limited. The uplift history, with gas expansion when the pressure reduces, means that gas is expected to be the most probable hydrocarbon phase for possible reservoirs. A shallow reservoir depth with low gas density in the reservoirs indicates that the volume in the Jurassic prospects will be limited.

Source rocks

One of the biggest geological challenges in the new areas in Barents Sea South-East is the presence of source rocks which may have formed oil and gas in sufficient quantities to fill the structures mapped. The challenge for gas is relatively simple, since coal horizons and organic material are assumed to be present in both Lower Carboniferous rocks and large parts of the Triassic. In addition, organically rich dark shales and limestones in the Carboniferous and Lower Triassic could be relevant contributors to gas. A number of large and small gas discoveries in the Russian sector indicate that gas is present in the area. On the Norwegian side, the

Norvarg Dome represents the most relevant analogue trap type in the platform areas. This is also a gas discovery. The biggest risk for the presence of gas in the new areas is retention in the structures because of Quaternary uplift. The source potential for gas must be characterised as satisfactory.

The source-rock challenge is greater for oil. Seismic data for the new areas show that the traditional source rock in the Upper Jurassic, which has formed an estimated 98 per cent of all known petroleum on the NCS, is not buried deeply enough to have given rise to oil or gas. There are few places where this source rock lies deeper than 1 200-1 500 metres today. Even though these rocks have been more deeply buried (1 000-1 500 metres) for a time, that would have been insufficient to initiate oil formation. This immaturity is documented in shallow drilling on the Sentralbanken High, where the organic content is high and has a composition favourable for oil formation but where the temperature has been too low. Finding other source rocks which could have formed oil will accordingly be necessary.

In and around the Nordkapp Basin, a small oil discovery has earlier been made in well 7228/7-1 A. A similar find was made on the Finnmark Platform with well 7128/4-1. The source rock for these two discoveries probably hails from the Lower Triassic or older. This source rock has accordingly been indirectly proven by discoveries, but not confirmed by drilling. The great uncertainty related to this source rock is whether it has sufficient volume to generate oil in commercial quantities.

The discovery on the Finnmark Platform lies in Permian sediments. This oil almost certainly derives from a Carboniferous source rock. Carboniferous limestones and dark shales have the potential to form oil and gas. This type of rock outcrops at Billefjord in Svalbard. Traces of oil in the Pyramiden mines and vaporisation of volatile petroleum further up the fjord show that Carboniferous source rocks have a potential to form petroleum. The probability that this has happened further south in the Barents Sea is relatively high. However, the volumes of oil which may have formed are very uncertain. This uncertainty relates both to the quantity of available source rock and how deep it is buried. If the source rock has been too deeply buried, it will cease to form oil. In such circumstances, the source rock is more likely to have formed gas.

Seismic data from the eastern areas show that a large delta or continental shelf edge has formed in the Lower Triassic and extended in a north-westerly direction from land. Ahead of this delta, the strata thin out and reveal a condensed sedimentary package which probably comprises black marine shales with an unknown content of organic material. This shale formed before the salt movements in the basins and is unaffected by disruptive folding, erosion and rapid sedimentation around the salt diapirs. The assumed shale in the Lower Triassic could potentially be a source rock for oil and gas, providing it has an organic content with the right composition. Wells which could confirm that hypothesis have not been drilled in this area. Should the shale in the Lower Triassic have the right properties, it has been buried at a favourable depth for oil to form. The temperature decline in the rock related to the Quaternary uplift of the Barents Sea has probably halted the process of forming possible additional oil. As a result, the relevant oil in the prospects would have formed prior to the uplift process. Great uncertainty prevails about this source rock. Were it to be proven, however, it could be the most important contributor to possible oil discoveries in Barents Sea South-East.

In the northern and western parts of the Barents Sea, mature source rocks have developed in Middle Triassic marine shales. Seismic interpretation of the new areas in the southern-eastern Barents Sea shows that delta and delta plain deposits are more dominant, and it is less likely that marine shales have been depos-

ited in this area during the Middle Triassic. Great structural activity has also occurred in the Nordkapp and Tiddlybanken Basins, with the formation of salt plugs. This has led to rapid sedimentation around the plugs, which has also been unfavourable for the formation of marine source rocks in the Middle Triassic.

The migration of petroleum from source to reservoir rocks in Barents Sea South-East is assumed to have been essentially vertical. Little opportunity for inward migration from the east is offered by the regional structural picture. The Fedynsky High serves as a barrier here. At the same time, erosion on the Fedynsky High is fairly deep, so that much of the petroleum from the Jurassic and Upper Triassic in this area has probably leaked out.

In the NPD's view, the probability of oil formation is highest in areas close to the salt basins. The hydrocarbon phase around the salt plugs and on the edge of the deep salt basins is likely to be both oil and gas. On the Bjarmeland Platform, including a large dome in the north-east, the likelihood that the hydrocarbon phase will be gas is very high. Gas discoveries in both the Norvarg Dome and Shtokman support this assumption.

The probability of a source rock which has formed commercially interesting quantities of gas is good. However, it is very uncertain whether a source rock for oil exists in the area and whether a possible source rock has sufficient volume to be interesting in a petroleum context. The NPD basically regards Barents Sea South-East as a gas province, but is keeping open the option that oil could also have formed in the area. That applies particularly in and around the salt basins.

Resource evaluation

Methodology

Whether petroleum exists in an area is always uncertain. Calculating resources in plays takes account of this uncertainty by risk-assessing the various parameters of significance for the presence and retention of petroleum. Plays are also defined with uncertainty distributions for different reservoir and liquid parameters.

Defining plays is a method for systematising and grouping the geological parameters which characterise the play and which distinguish it from other plays.

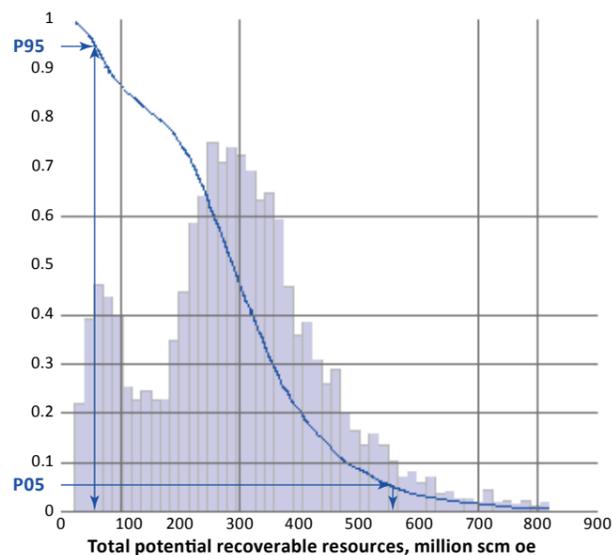


Figure 6.9 The distribution and cumulative probability distribution of total undiscovered recoverable resources in Barents Sea South-East based on the play method. The bimodal probability distribution reflects the fact that interdependencies have been incorporated between several plays.

Results

The most important reservoir rocks in Barents Sea South-East are found in Triassic sandstones. Jurassic and Lower Carboniferous sandstones, as well as Carboniferous/Permian limestones and reef structures, could also be relevant as reservoir rocks. The NPD has defined and mapped a number of plays in sediments from the Carboniferous/Permian to the Jurassic in Barents Sea South-East, and has performed a stochastic resource calculation. The risk assessment is based on the presence and retention of petroleum and uncertainty assessments of the various petroleum geology parameters.

A number of plays which coincide with the various main structural elements in Barents Sea South-East have been defined by the NPD. These relate to the Early and Late Carboniferous on the Finnmark Platform, and to the Triassic in the northern part of that area. Various Triassic plays have been defined in the Tiddlybanken and

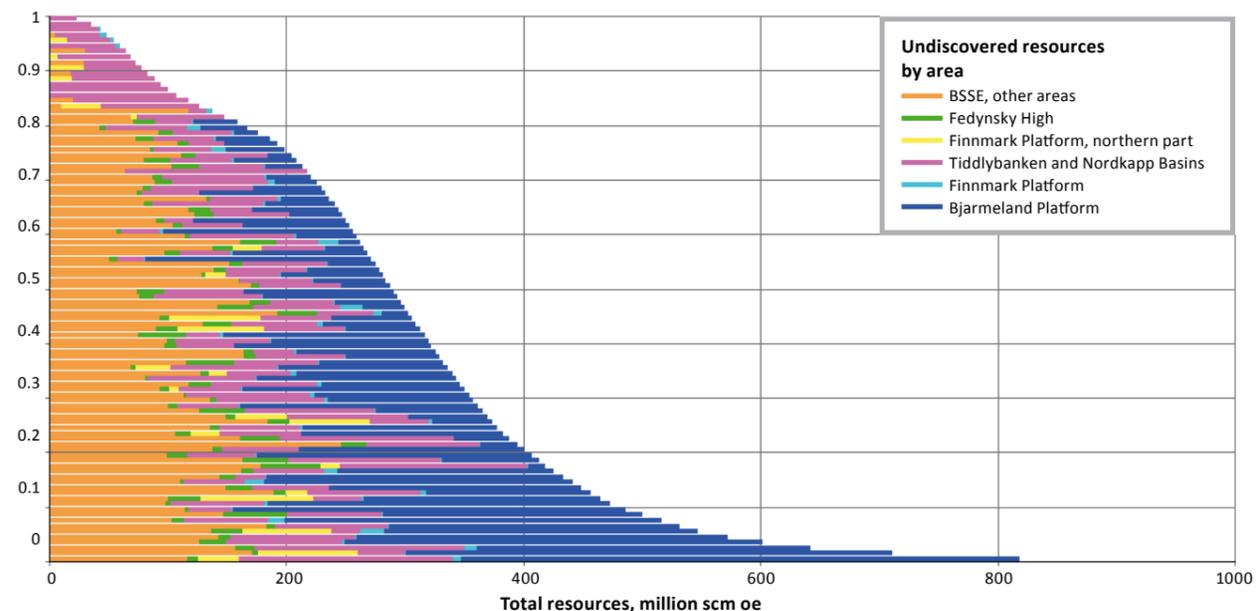


Figure 6.10 The cumulative distribution of total recoverable resources in Barents Sea South-East. The various plays are grouped by structural elements and other areas in the region.

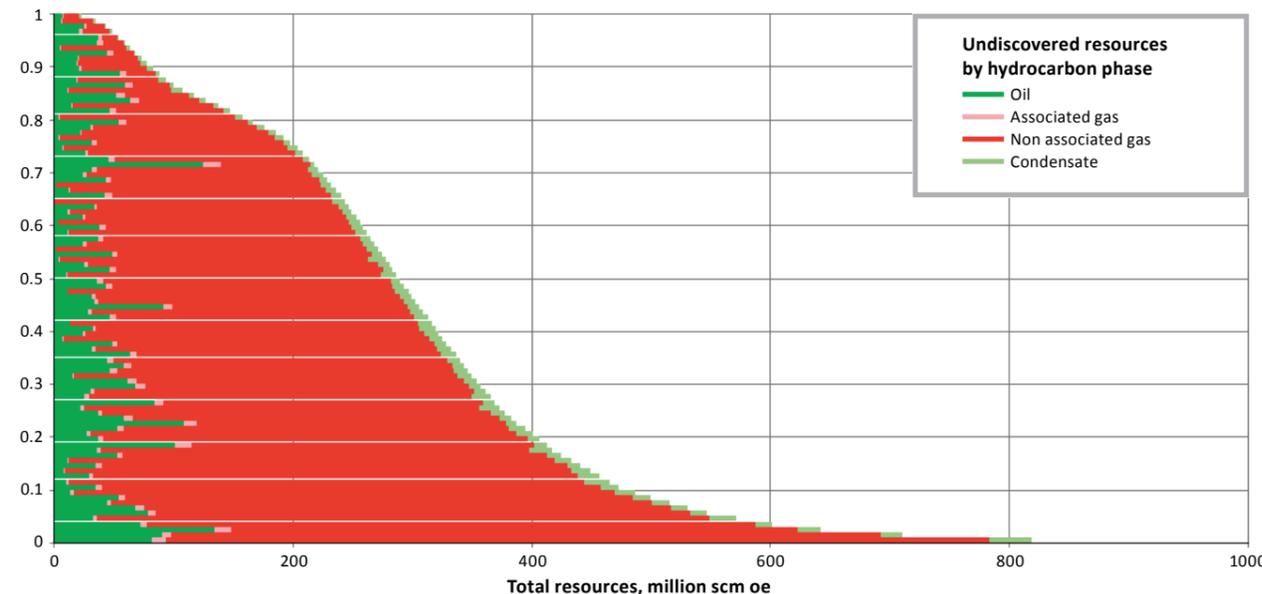


Figure 6.11 The cumulative distribution of recoverable oil and gas resources in Barents Sea South-East.

Nordkapp Basins, while plays on the Bjarmeland Platform are both Jurassic and Triassic. Various Triassic plays are defined on the Fedynsky High. Carboniferous, Triassic and Jurassic plays have been defined in the other parts of Barents Sea South-East.

Expected recoverable resources for Barents Sea South-East are estimated to be about 300 million scm oe, with a downside (P95) of 55 million scm oe (95 per cent probability that the resources are equal to or greater than 55 million scm oe) and an upside (P05) of 565 million scm oe (five per cent probability that the resources are equal to or greater than 565 million scm oe). The probability and cumulative distributions of the recoverable resources are shown in figure 6.9. Since at least one play extends into the open part of the Barents Sea and has been proven there by a discovery, at least one of the plays in Barents Sea South-East is confirmed and will consequently yield finds.

Interdependencies are expected between several plays, partly with regard to the presence of effective source rocks. Should drilling of a well prove a source rock which functions, the probability that this source rock functions for more plays will be high. Interdependence in source rock applies in part to several plays with potentially large resource volumes. This emerges clearly as a bimodality in the resource distribution. See figure 6.9. The resource distribution has two resource estimates with a relatively high probability (bimodality). The higher of these shows the effect of proving a source rock in a play which increases the probability that this will also be proven in other interdependent plays with expected high resource estimates.

Figure 6.10 presents the cumulative distribution of the recoverable resources, where the contribution from the various plays emerges clearly. The plays on the Bjarmeland platform contribute most to the high resource estimates.

The expected recoverable resources break down into about 50 million scm of liquids and roughly 250 billion scm of gas. See figure 6.11. It is uncertain whether the area contains oil-forming source rocks, and whether a possible source rock has had sufficient volume to be interesting in a petroleum context. As a result, more gas than oil is expected in Barents Sea South-East. The Bjarmeland Platform and Fedynsky High are considered to be pure gas prov-

inces, while the Nordkapp and Tiddlybanken Basins plus the Finnmark Platform are regarded as combined oil and gas provinces.

Estimates for undiscovered resources in Barents Sea South-East are uncertain. The potential for finding oil and gas is high. Gas is expected to account for 85 per cent of the resources and oil for 15 per cent. Confirmation of plays through discoveries could offer a substantial resource upside.

Adding the undiscovered recoverable resources for Barents Sea South-East to the estimate for the Barents Sea of 31 December 2012 increases undiscovered recoverable resources for this part of the NCS by 31 per cent. See figure 6.12.

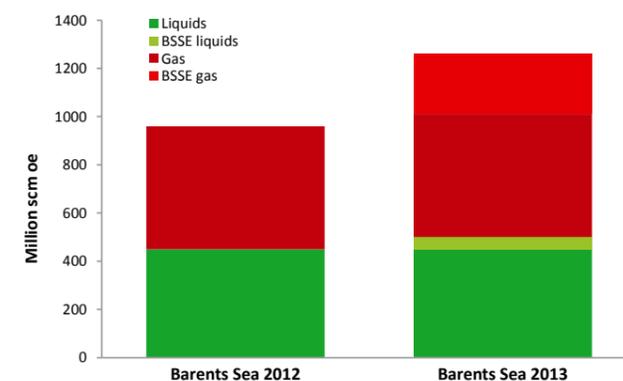
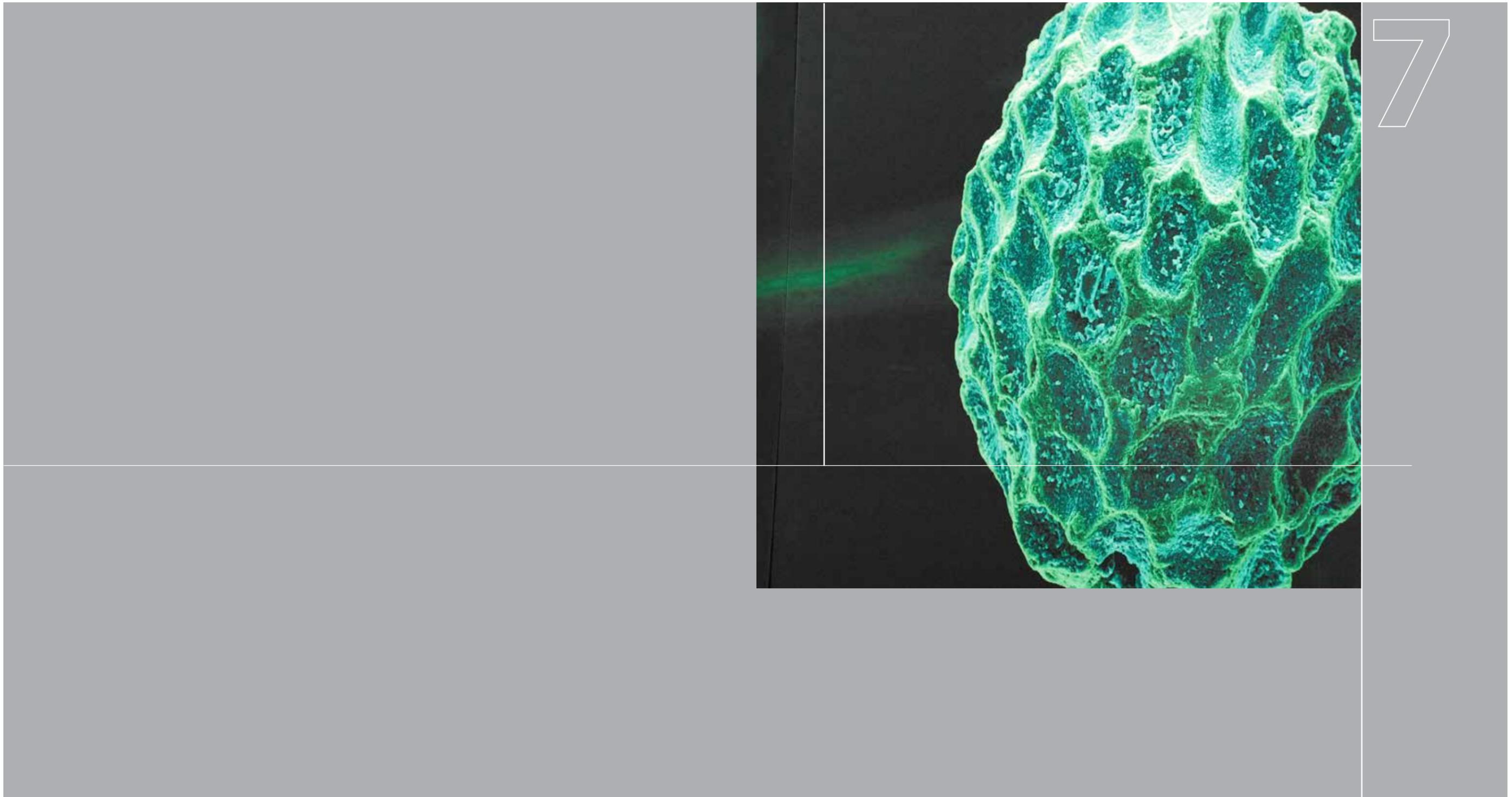


Figure 6.12 Distribution of undiscovered recoverable liquid and gas volumes for the Barents Sea in the 2012 analysis and in 2013 with Barents Sea South-East (BSSE) included.

Jan Mayen



7

Norway and Iceland reached agreement on 22 October 1981 over the continental shelf boundary between Iceland and Jan Mayen. This agreement called for the establishment of a special collaboration over petroleum activities in a defined part of this area. Covering a total of 45 470 square kilometres, the collaboration area breaks down into 32 750 square kilometres on the Norwegian side of the boundary, and 12 720 square kilometres in the Icelandic sector. See figure 7.1.

Iceland can participate with a 25 per cent share in that part of the collaboration area which lies north of the boundary, while Norway can participate with a corresponding share in that part located south of this line.

The Norwegian government initiated an opening process for petroleum activities in the Norwegian sector of the continental shelf around Jan Mayen in 2010. This process covers an area of about 100 000 square kilometres, bounded by the Greenland continental shelf to the west and the Icelandic continental shelf (ICS) to the south. See figure 7.1. The work includes data acquisition and geological mapping with a view to evaluating the resource potential for petroleum, as well as an environmental impact assessment. These studies will form the decision base for a possible opening.

Iceland carried out its first offshore licensing round in 2009, without awarding any production licences. The country concluded its second round on 4 January 2013 with the award of two licences. Petoro is a participant in both. These licences lie at the northern end of Iceland's share of the collaboration area, on the boundary with the Norwegian sector.

Pursuant to the 1981 agreement, data have been acquired through a collaboration between Norwegian and Icelandic institutions. Scientific bodies and commercial companies have also collected geological information in the area.

On behalf of the Ministry of Petroleum and Energy, the NPD has mapped the potential for oil and gas resources in the Norwegian sector around Jan Mayen. This work began in 2011, and the first results of the resource mapping were presented in February 2013. However, the NPD's mapping of the area has not been completed. It will continue to analyse seismic data acquired in 2011 and 2012.



Figure 7.1 Bilateral boundaries, the collaboration area with Iceland and the area covered by the opening process.

Analysis results from seabed rock sampling conducted in 2012 will also become available in 2013. Furthermore, the Storting has appropriated funds for additional geological mapping around Jan Mayen. Shallow stratigraphic wells are planned by the NPD. The Ministry of Petroleum and Energy has requested an upgraded assessment of the potential for oil and gas on the NCS around Jan Mayen by March 2014.

Data

Geological data

Three shallow boreholes were drilled in 1974 on the Jan Mayen Ridge as part of the Deep Sea Drilling Project (DSDP). These passed through a shallow unconformity (erosional discordance) into the underlying rocks. See figures 7.2 and 7.3.

The two northernmost locations (346 and 347) were drilled to about 190 metres beneath the seabed, while the southernmost (349) went down to roughly 320 metres. Above the clear unconformity – see figure 7.3 – the boreholes passed through fine-grained sediments deposited at the boundary between the Oligocene and the Pleistocene. See the geological timescale at the end of this report. Fine-grained sediments dated to Late Eocene/ Early Oligocene predominated beneath the unconformity. The location of the boreholes was determined on the basis of seismic data which today look very inadequate. More recent seismic data show that the deepest and best documented borehole (DSDP 349) was drilled in a heavily faulted area beneath the unconformity which is difficult to interpret in detail. The results of the borehole accordingly provide limited information about the rocks.

Geological samples were collected by the NPD in 2011 and 2012 using a remotely operated vehicle (ROV). This work was done in collaboration with the University of Bergen. A gripper arm was used in 2011 to break off rock samples, and a chain saw in 2012 to cut them out. Both sampling campaigns were successful. A number of samples were acquired in both Icelandic and Norwegian sectors. See figure 7.4. Analysis of the 2011 samples has largely been completed, while those from 2012 are being processed. The material has provided important new information about the bedrock on the Jan Mayen Ridge, as illustrated in figure 7.8.

Geophysical data

The NPD first acquired seismic data across the Jan Mayen Ridge in 1979. This was followed up in 1985 and 1988, when seismic surveys were conducted on both sides of the Norwegian-Icelandic boundary in cooperation with the Icelandic authorities. Since then, seismic data have been acquired on the ICS in 2001 and 2008. Nevertheless, the overall coverage was very low – particularly on the Norwegian side. The decision was taken in 2011 to acquire seismic data from the whole area under consideration for opening around Jan Mayen, a total of 15 lines adding up to 3 060 kilometres. Data acquisition was concentrated on the Jan Mayen Ridge south of the island and the neighbouring areas on both sides of the main ridge. See figure 7.5. This was followed up in 2012 with the acquisition of 64 lines totalling 9 508 kilometres.

GeoStreamer technology was used in both 2011 and 2012, with the hydrophone streamer towed at a substantially greater depth than normal. That means the operation can be conducted in poorer weather conditions (higher waves) and thereby becomes more efficient.

Gravimetric and magnetometric data have also been acquired along most of the seismic lines with a view to securing additional information, particularly about the deeper rocks.

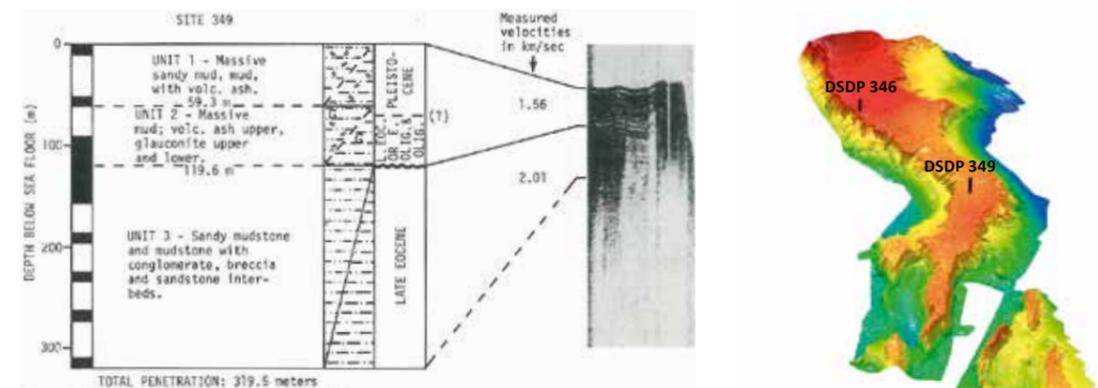
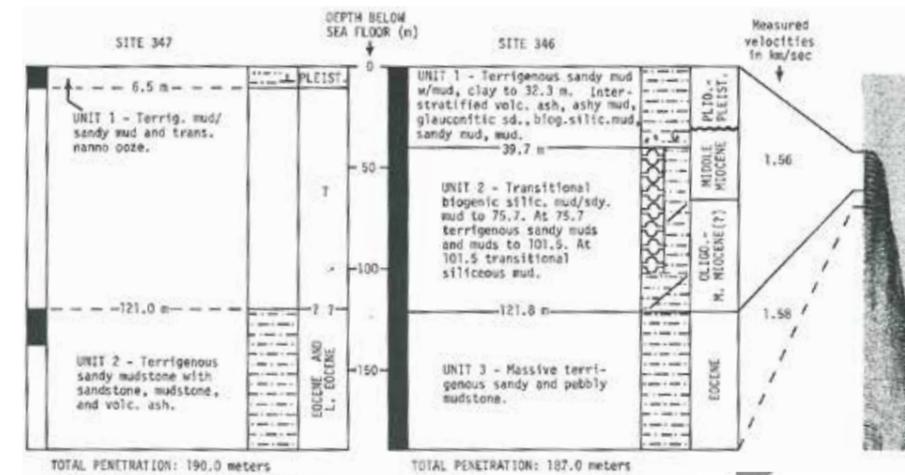


Figure 7.2 Rocks proven in the boreholes drilled by the Deep Sea Drilling Project in 1974 (Talwani et al, 1976, volume 38). The map shows the location of the two boreholes on a seabed map of the Jan Mayen Ridge.

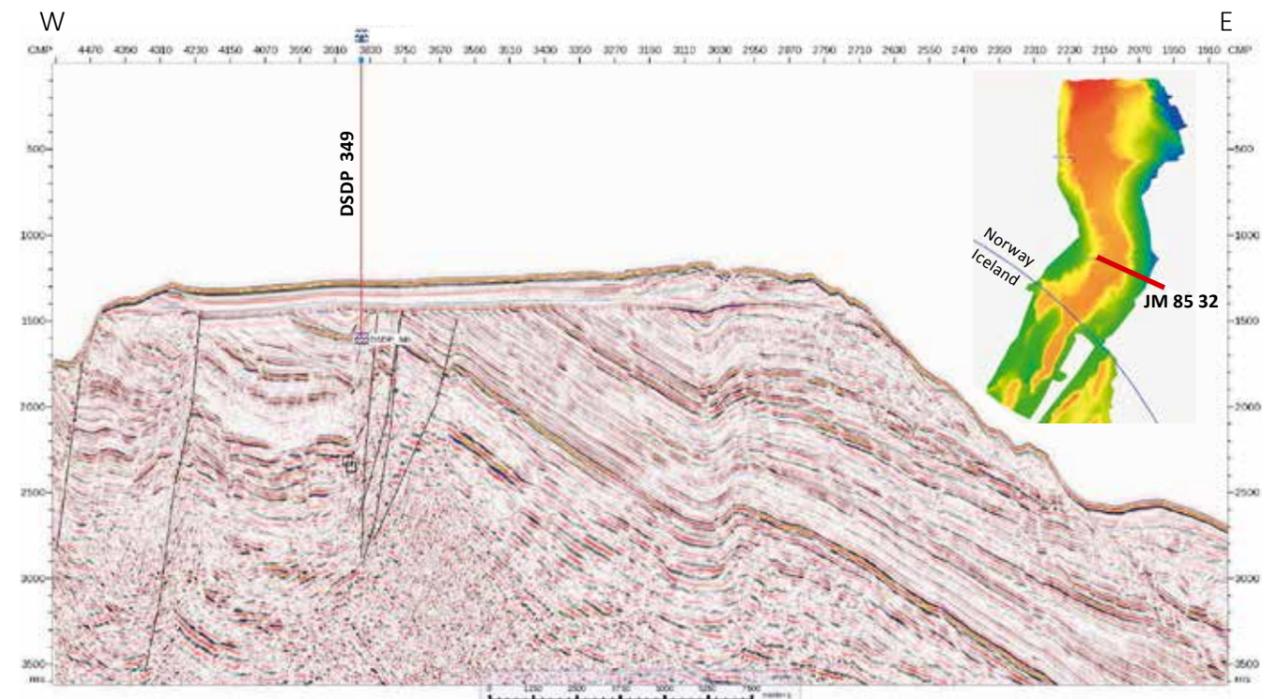


Figure 7.3 Seismic line NPD-85-32 (reprocessed by Spectrum in 2008-09) showing the location of DSDP 349 (vertical line). The line also shows the regionally widespread unconformity (erosional discordance) between the Upper and Lower Oligocene at a time depth of about 1 500 milliseconds (ms), which corresponds to some 1 150 metres.

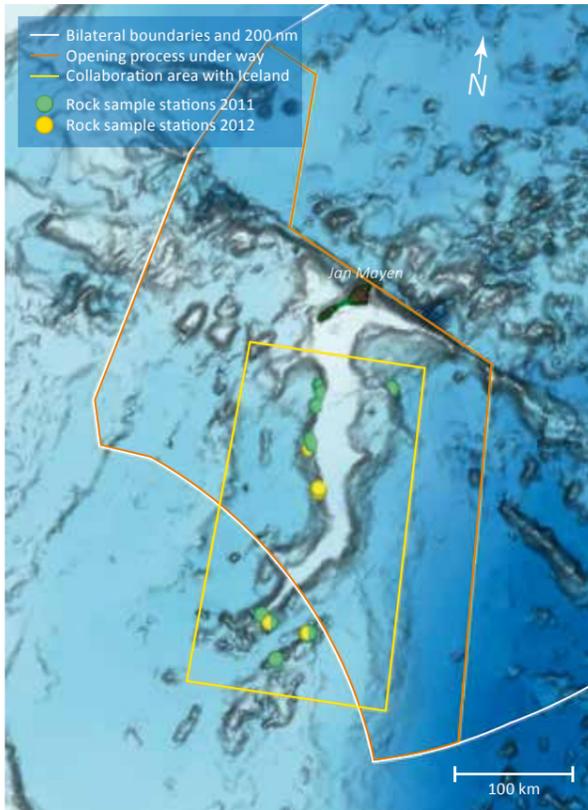


Figure 7.4 Sampling stations for ROV surveys in 2011 and 2012, shown in green and yellow.

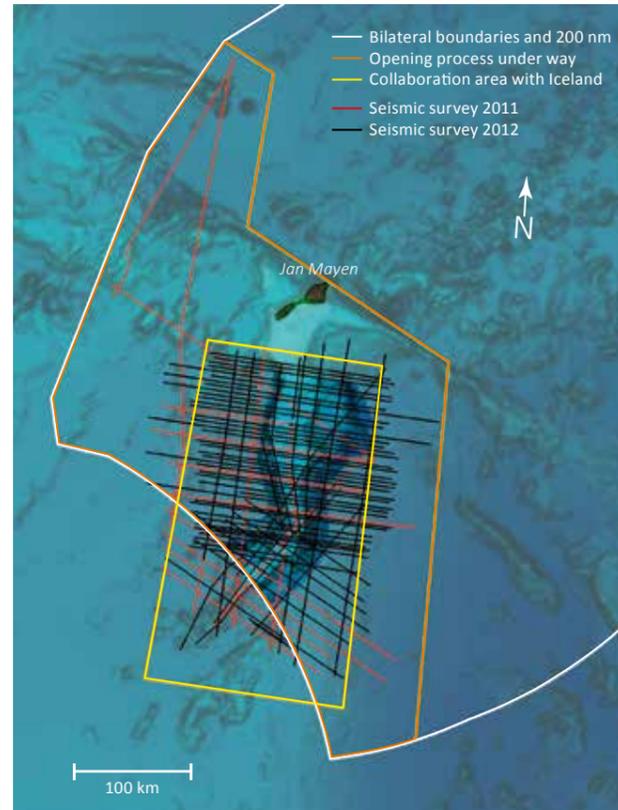


Figure 7.5 2D seismic data acquired by the NPD in 2011 (red) and 2012 (yellow).

Water depth data across central parts of the Jan Mayen Ridge – see the seabed map in figure 7.2 – were acquired in the summer of 2010 in close cooperation with the Icelandic authorities, who have acquired similar data on their side of the boundary. This information is used in the geological mapping as well as in planning locations for ROV sampling and seismic surveys.

Aeromagnetic surveys were conducted over the Jan Mayen Ridge as early as 1976. Such data were later acquired over the eastern part of the ridge in both 2005 and 2011-12. These two data sets

have been acquired in collaboration with such bodies as the Norwegian Geological Survey (NGU) and Iceland's National Energy Authority. Among other contributions, they help to delineate the prospective area south-east of Jan Mayen. Table 7.1 provides an overview of the relevant data for mapping the Jan Mayen Ridge.

Work on securing the best possible input data for enhancing knowledge of the petroleum geology is still under way. Shallow boreholes are due to be drilled on the Jan Mayen Ridge and the outer parts of the Møre Margin. The intention on the Jan Mayen

Data	
Shallow boreholes	Deep Sea Drilling Project 1974
Bathymetry, multibeam echo sounder	Icelandic vessel, Norwegian sector, 2010
2D seismic	1 200 km, NPD, 1979
2D seismic	3 000 km, NPD/Icelandic authorities, 1985
2D seismic	1 500 km, NPD/Icelandic authorities, 1988
2D seismic	Commercial surveys, ICS, 2001 and 2008
2D seismic	3 060 km, NPD, 2011
2D seismic	9 508 km, NPD, 2012
ROV, <i>G O Sars</i>	Sampling with gripping arm, NPD/University of Bergen, 2011
ROV, <i>G O Sars</i>	Sampling with chain saw, NPD/University of Bergen, 2011
Aeromagnetic survey	NPD, 1976
Aeromagnetic survey	NGU/NPD and others, 2005
Aeromagnetic survey	NGU/NPD/Icelandic authorities, 2011-12

Table 7.1 Overview of the most relevant data for mapping the Jan Mayen Ridge.

Ridge is to complement and improve existing information about the Cenozoic rocks. In addition to improved understanding of the local geology, shallow drilling on the Møre Margin will be relevant for understanding Jan Mayen because these two areas were adjacent to each other until the Eocene.

Main geological features

Jan Mayen is a volcanic island at the northern end of the Jan Mayen Ridge. Running north-south, the latter is a submarine feature extending about 400 kilometres from Jan Mayen towards the Iceland Plateau. At its southern end, the main ridge splits into several smaller ones. Water depths along most of the ridge descend quickly to about 600 metres south of the island, and sink further to roughly 1 000 metres over much of the main ridge. Depths on the Iceland Plateau south and west of Jan Mayen are about 2 000 metres, while they descend eastward towards the Ægir Ridge to a depth of more than 3 500 metres. The ridge is bordered to the north by the Jan Mayen fracture zone, just north of the island, where the water depth drops steeply towards about 2 500 metres.

The opening of the North Atlantic began 55 million years ago. During the Cenozoic, the Jan Mayen Ridge tore free from both Norway and Greenland and was left out in the ocean as a separate "microcontinent". This comprises continental rocks similar to those found in eastern Greenland and on the NCS in the Norwegian Sea. See figure 7.7. The Jan Mayen microcontinent (JMM) was formed by an initial separation from the NCS early in the Cenozoic (Early Eocene) as a result of seafloor spreading along the Ægir Ridge, and a subsequent separation from the Greenland continental shelf through seafloor spreading along the Kolbeinsey Ridge.

The JMM comprises a larger area than the actual Jan Mayen Ridge alone. It is unclear whether it extends beneath Jan Mayen itself, or whether its northern limit runs a little south of the island. The southern boundary is also unclarified. The JMM extends a good way south into the Iceland Plateau and possibly right beneath north-eastern parts of Iceland. Its eastern limit is assumed to lie just east of the boundary of the Jan Mayen Ridge, while its western edge is expected to extend into the Jan Mayen Basin west of the ridge. See figure 7.6.

Rocks and structures in the JMM are little known, particularly at deeper levels. Nevertheless, the location of the microcontinent

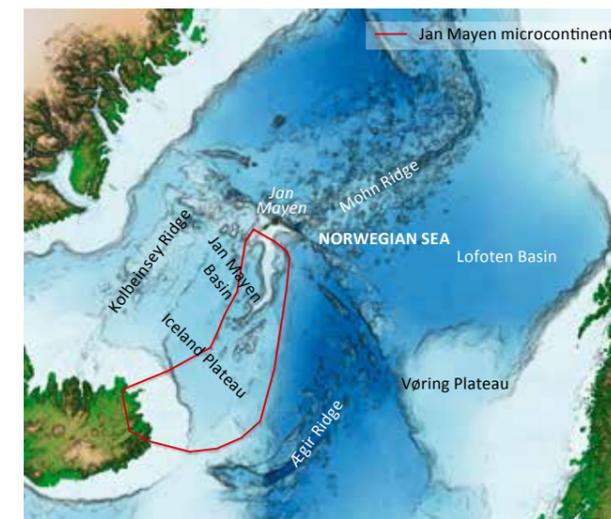


Figure 7.6 Structural elements in the Jan Mayen area and the assumed extent of the JMM.

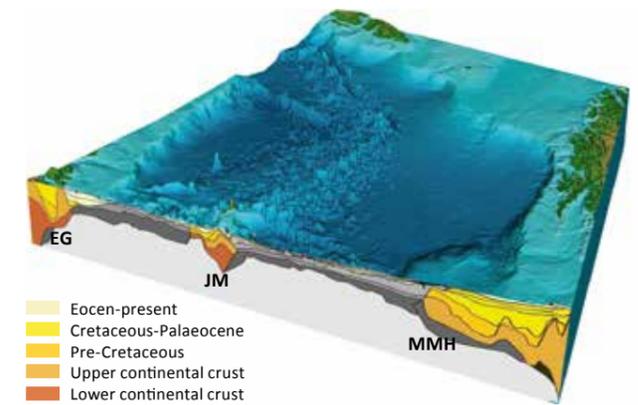


Figure 7.7 A geological cross-section of the Norwegian Sea from eastern Greenland (EG) in the west, across the JMM, to Norway (MMH). The two major continents on either side of the sea are coloured in yellows and browns in the same way as the microcontinent. The grey strata between the continents comprise young seabed crust formed of volcanic rocks without petroleum potential (crustal cross-section taken from Mjelde et al, 2008, Marine Geophysical Researches).

up to its formation in the Cenozoic conveys information about the rocks likely to be found. During the period from the Caledonian orogeny in the Late Silurian to the start of seafloor spreading in the Early Eocene, the area including the JMM lay between eastern Greenland and Norway. These areas then formed a single continent and experienced the same geological development.

The system of rock layers, unconformities, folds and faults making up the crust of the JMM is more complicated than elsewhere on the NCS. While this is demanding to map and interpret, it provides the key to the understanding of tectonic development and geological history which is necessary for evaluating the resources in the area.

Structural geology

Structural geology describes how the Earth's crust is built up and how that process occurs over time. Known as tectonics, from the Ancient Greek word *tektōn* or carpenter, this is the science of how the crust has formed. The building materials are the various rocks, assembled in different ways. First and foremost, they are deposited through time as a succession of rock layers (also called a lithostratigraphic sequence). These layers have then been deformed, carved up, transported and reassembled to a greater or lesser extent by crustal forces and movements. How this has occurred in a given location can be traced in part from the way the strata have been folded and offset along faults. Such structures form when the crust is compressed horizontally (strata are folded) or extended (strata are torn apart and displaced along faults). But the crust can also be subject to forces acting vertically, lifting or lowering the rocks over time. When an old succession is elevated above sea level, the rocks will be eroded by wind and weather to create erosional surfaces. Today's land areas are an erosional surface of this kind. When they then sink below sea level again, they are covered with layers of new sediment which convert into rock in their turn. In that way, the erosional surfaces are preserved in the overall succession as clear breaks or hiatuses in the deposition history, and are termed unconformities or (erosional) discordances.

The main force behind tectonics is the motion over time of the planet's major crustal plates. Tectonic forces are particularly strong along the boundaries of these plates, whether they are colliding and being squeezed together or moving apart to form new plate boundaries. Mountain chains form where two continental plates collide. The Himalayas, for example, are a result of the on-going collision between the Indian and Asian plates. Where a plate is splitting apart, an initial rift valley gradually expands until a new ocean ultimately opens between the two sections of the original continent. The African continent, for example, is breaking apart along east Africa's Great Rift Valley. The Atlantic Ocean represents the next stage, with the continents on either side of the ocean – which were once joined – being steadily driven further apart. These processes are known as plate tectonics.

The JMM crust is tectonically complicated because it has been at the heart of an area where plate boundaries have developed over geological time. Since the start of the Cambrian about 550 million years ago, the continental margins of eastern Greenland and western Scandinavia have experienced two major plate tectonic events – the continental collision which created the Caledonian mountain chain, and the continental separation with the opening of the North Atlantic. These two incidents divide the tectonic history of the area into three main periods.

1. Cambrian to Middle Devonian (about 550 to roughly 400 million years ago). As today, Greenland and Scandinavia lay on separate continents on either side of the Iapetus Ocean. During the last half of the period, the two plates began to move towards each other and the intervening ocean steadily closed. Finally, the two landmasses collided and created the Caledonian mountain chain in the process of joining to form a new continent.
2. Middle Devonian to Eocene (about 400 to roughly 55 million years ago). The area was primarily characterised by crustal extension and rift valley formation. This culminated with the re-separation of the continent between Greenland and Scandinavia at the boundary between the Late Palaeocene and the Early Eocene, which marked the start of today's North Atlantic.
3. Early Eocene to the present, comprising the active opening of the North Atlantic through seafloor spreading between Greenland and Scandinavia. At the beginning of this period, today's JMM was part of Greenland. Later, about 25 million years ago, the JMM separated from Greenland after a period of widespread crustal extension in the area. Since then, seafloor spreading has continued to open the ocean between Greenland and Jan Mayen.

A closer look at the two latest principal periods is relevant for this report.

During the first part of the middle period, from the Middle Devonian to the Eocene, all the continents were assembled into a single large landmass – the supercontinent Pangea (from the Greek word meaning "all earth"). Pangea was formed through a series of plate collisions which raised mountain chains and brought together all the continents during the Devonian, Carboniferous and Permian. Although the supercontinent was primarily experiencing compression as a result of the plate collisions during this period, eastern Greenland and Scandinavia were locally subject to crustal extension. Such extension and rift valley formation occurred in several phases during the Early Carboniferous and at the boundary between the Carboniferous and Permian.

Plate collisions declined around Pangea at the end of the Permian, about 250 million years ago, and the supercontinent began its long global process of breaking up, which is still on-going. Tectonically, the Middle Triassic to the end of the Middle Jurassic was a quiet period throughout the area. The last part of the Middle Jurassic, about 165 million years ago, saw the start of a very active phase with crustal extension across the whole area. This persisted through the Late Jurassic into the Early Cretaceous. During this Kimmeridgian rift phase, a major system of rift valleys formed on the NCS. These were filled with the most important reservoir sandstones and source rocks, deposited from the North Sea to the Barents Sea to form the basis for such fields as Statfjord, Oseberg, Gullfaks, Troll, Heidrun, Åsgard and Snøhvit. That was followed by a phase when areas subject to this crustal extension began to subside because the crust cooled down and became heavier when the extension process had ended.

The areas between Greenland and Norway where the crust was most extended and thinned subsided to become very deep sedimentary basins, which were filled during the Cretaceous with sediments several kilometres thick (including the Møre and Vøring Basins). This subsidence was reinforced by further crustal extension and block faulting, first in a possible phase in the Albian (about 110 million years ago) and then at the boundary of the Turonian and Coniacian (roughly 90 million years ago).

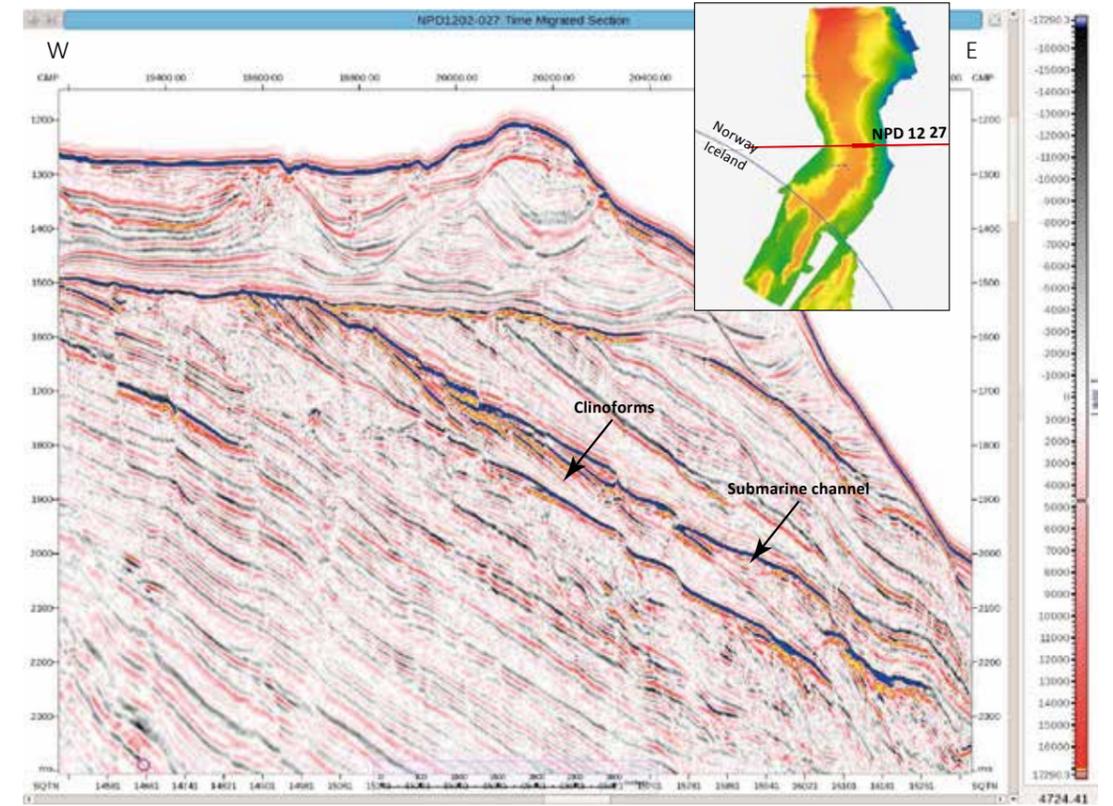


Figure 7.9 Interpretation of Eocene delta progradation, with channels and clear clinoforms showing progradation towards the east.

The crustal extension phase ended in the Palaeocene. It was powerful and rapid, and led to the final separation of Norway from Greenland. At the same time, major volcanic eruptions produced enormous volumes of lava at the transition to the Eocene about 55 million years ago. These lava layers in the Jan Mayen area pose a big problem for mapping because they prevent seismic signals penetrating to the underlying sediments. This means in turn that the seismic data do not show strata from the second main period (Middle Devonian to Eocene). In so far as sedimentary successions from this period are present in the JMM, they will have undergone the tectonic development summarised above.

A good picture of the sedimentary successions and tectonic structures in the final main period, above the lava layers, is provided by the seismic data. The JMM appears on the seabed as a narrow uplifted main ridge in the north, which is split up southwards in the Icelandic sector into a number of lower ridges and blocks. The main ridge comprises a steep fault escarpment to the west, a gentler flank to the east and a flat summit. Internally, the ridge is far more complex. To the south, the eastern sections show a relatively simple picture with the sedimentary successions sloping regularly to the east. See figure 7.3. Westwards and northwards under the top of the ridge, the strata are broken up in a complicated fault pattern. These faults are associated with large and small folds. Farthest to the west, everything is truncated by a large fault escarpment.

The flat top of the ridge reflects an erosional discordance which truncates all internal structures. This surface is overlain by a thin sequence of largely flat sedimentary layers (the discordance surface is about 1 500 milliseconds down on the seismic profile in figure 7.3). In the DSDP 349 borehole shown in figure 7.3, the strata below and above this discordance have been dated to the Late

Eocene/Early Oligocene and the Late Oligocene respectively. This means that faulting activity and folding, with subsequent uplift and erosion, must have occurred during a relatively short period at the transition to the Late Oligocene. This tectonic activity is attributed to the phase of crustal extension and the final separation of the JMM from Greenland. The process has probably comprised an early phase with substantial extension plus the development of normal faults and large fault blocks, which was replaced by a compression and folding phase.

The flat discordance with the deep erosion of the Jan Mayen Ridge shows that it was substantially uplifted and then eroded down to sea level. This means that the sea level must also have been relatively stable at the transition to the Late Oligocene. The big lower-lying fault blocks in the Icelandic sector to the south have also been uplifted but not eroded. They must have lain beneath sea level throughout or been rapidly inundated. During the Late Oligocene, the Jan Mayen Ridge itself subsided beneath sea level. Since then, the region has been more stable.

Rocks

Earlier shallow drilling and sampling in recent years on the Jan Mayen Ridge have secured rock samples from the Triassic, Jurassic, Cretaceous and Cenozoic. Samples collected by an ROV with a chain saw in 2012 (see figures 7.4 and 7.8) show that only those from the Cenozoic are definitely indigenous. All the older samples are probably material carried in icebergs from eastern Greenland and dropped over the ridge when the ice melted.

The Cenozoic samples confirm thick layers of lava from the continental break-up in the Palaeocene-Eocene. Seismic data show that these layers have a regional distribution and almost certainly belong to the big North Atlantic lava province formed at the time

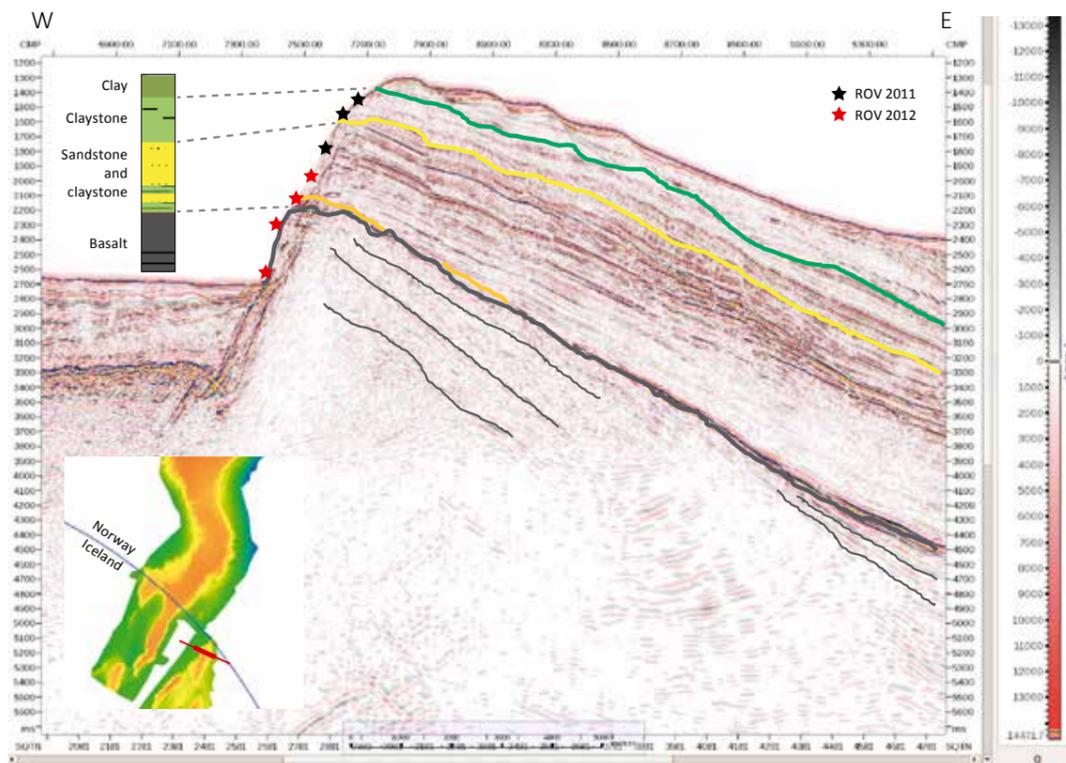


Figure 7.8 Samples acquired by ROV from outcrops on the Icelandic sector of the Jan Mayen Ridge. The column shows rocks which are very probably representative for this part of the ridge complex.

of this continental break-up. In addition, the samples show that the lava layers are overlain by quartz-rich sandstone followed by alternating shales and siltstones. The seismic data also provide details which have been interpreted as possible delta developments of these sediments from west to east, labelled as clinofolds and channel structures in figure 7.9. This means that these sediments were deposited at the end of a river system which then drained the inner regions of eastern Greenland, before the JMM split off. These quartz-rich sandstones could be good reservoir rocks. Fine-grained material under the quartz-rich sandstone is dated to the Eocene, while the overlying fine-grained sediments have been dated to the Eocene/Early Oligocene. Further up the sedimentary succession, the clear regional discordance lies beneath the Upper Oligocene. The latter probably formed immediately after the crust-extension process which ultimately separated the JMM from

eastern Greenland. See figure 7.3. This discordance is not preserved in eastern Greenland, where it would presumably have lain above the level of the Bopladsdalen and Krabbedalen Formations. See figure 7.10.

Seismic data show indications here and there of a sedimentary succession under the lava layers, but no reliable rock samples exist from this succession. However, it is likely to resemble the corresponding successions in eastern Greenland and on the NCS in the Norwegian Sea immediately south of the Jan Mayen fracture zone. Before seafloor spreading became established in the Eocene, the JMM formed an area between Kangarlussuaq-Jameson Land in eastern Greenland and the Møre Margin High on the NCS. See figure 7.11. Palaeogeographic comparisons conducted by the NPD and ocean bottom seismic (OBS) surveys show that the pre-Eocene

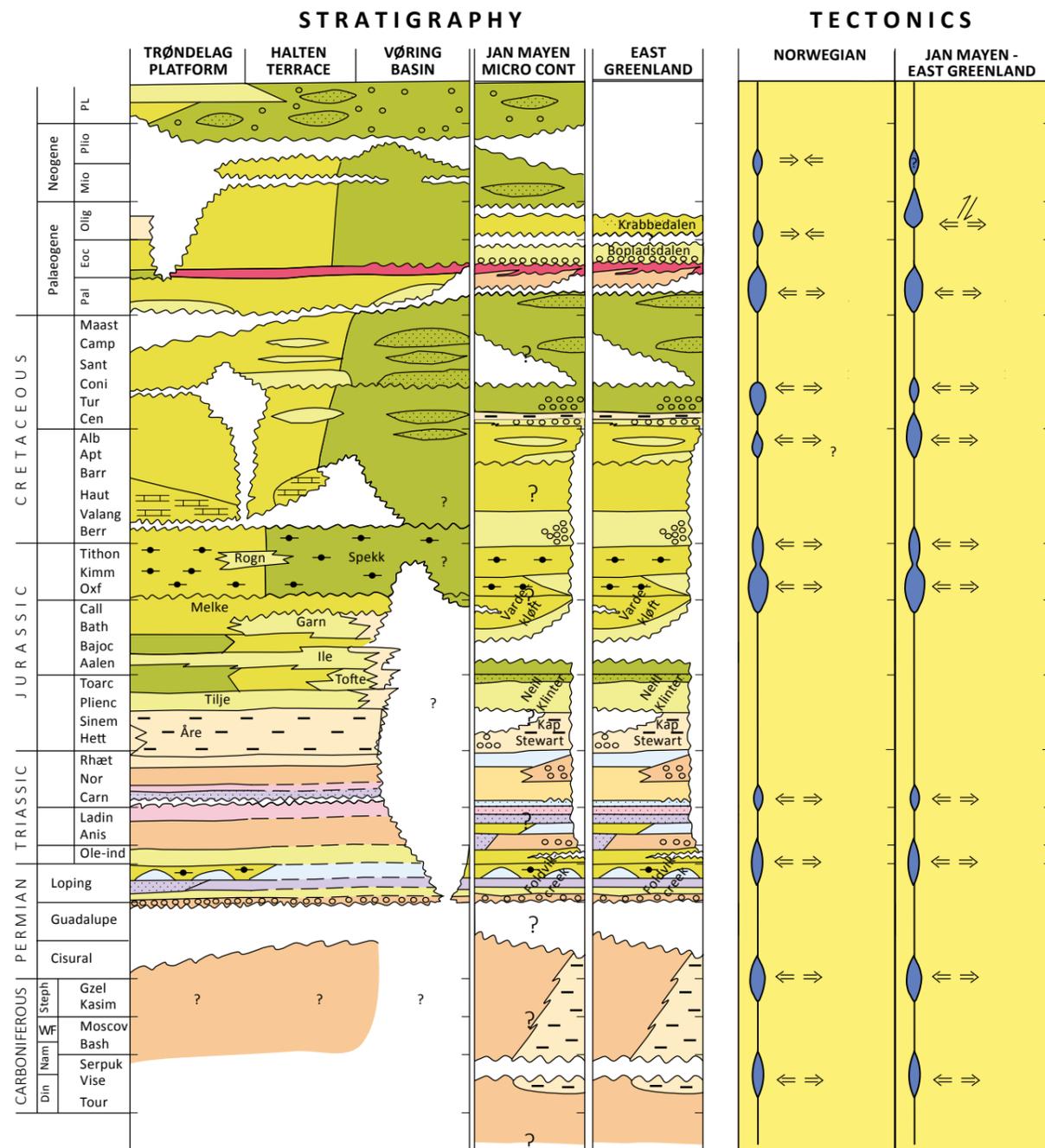


Figure 7.10 Juxtaposed stratigraphic columns for the continental margins in the Norwegian Sea and eastern Greenland, with the stratigraphy assumed for the JMM.

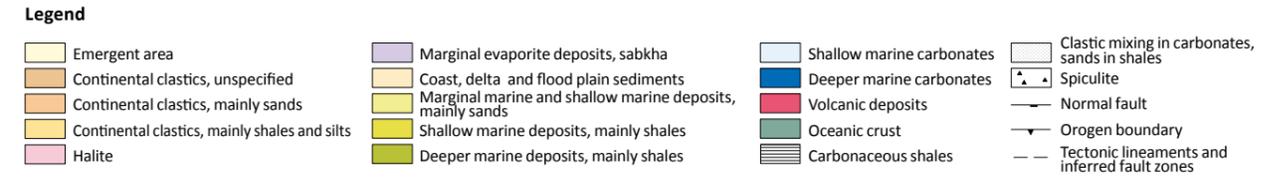
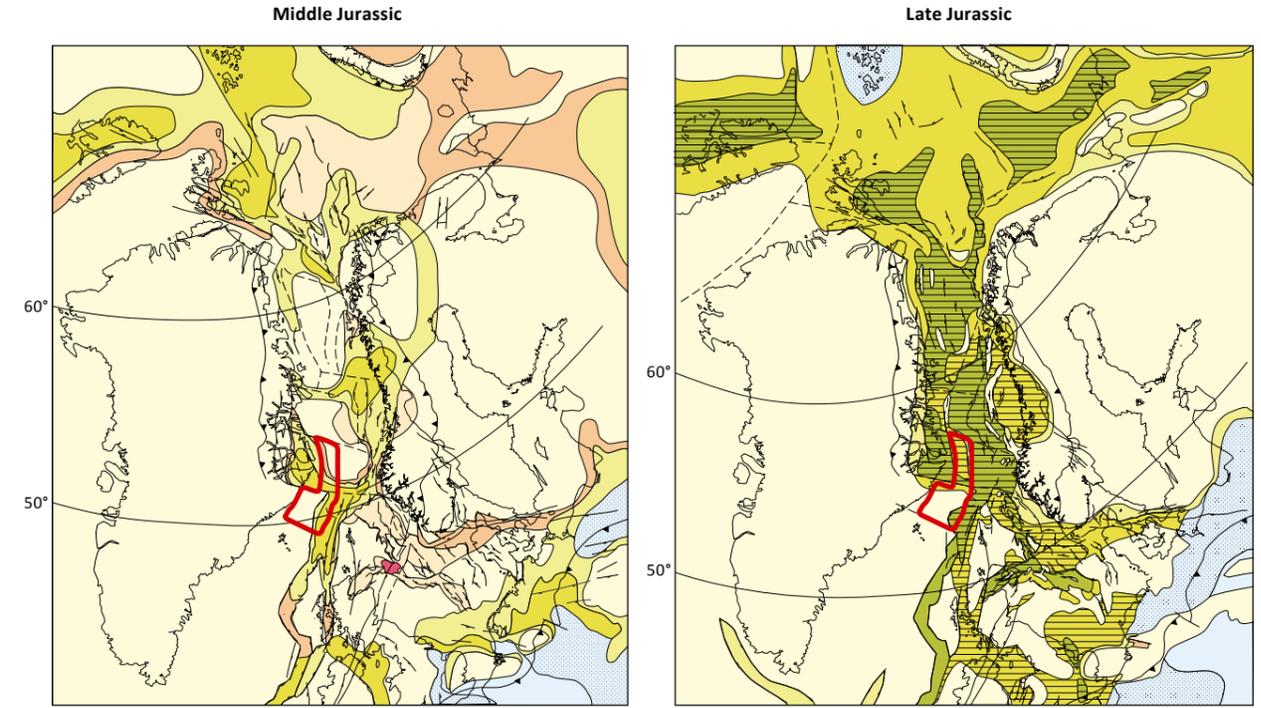


Figure 7.11 Palaeogeographic reconstruction of land areas and sediments in the Middle and Late Jurassic for the North Atlantic and Arctic areas (Brekke et al, 2001, NPF Special Publication 10). The position of the future JMM is outlined in red.

succession is very likely to resemble those on the Trøndelag Platform and Halten Terrace on the NCS and in Jameson Land in eastern Greenland with regard to both rocks and sedimentary thicknesses. See figures 7.10, 7.11 and 7.12.

During the Carboniferous, the JMM appears to have occupied the watershed between two seas – the Boreal to the north and the Tethys to the south. Carboniferous rocks are accordingly likely to comprise fluvial and lake sediments divided by areas with no deposition.

The Lower Permian is expected to comprise fluvial deposits as a continuation of the Carboniferous. At the boundary with the Late Permian, regional uplift and erosion in Greenland produced a marked erosional discordance. The sea level then rose and transgressed from the north, so that the Upper Permian probably comprises a shallow marine conglomerate overlaid by limestone and possibly by evaporites (salt deposits), and a black shale which could be a good source rock (called the Ravnefjell Formation in Greenland).

Continental fluvial deposits dominate the Triassic, with some marine elements – particularly on the Greenland side. A marine environment prevails on both Norwegian and Greenland sides, comprising evaporite deposits in the Middle to Upper Triassic. An older marine element also found on the Greenland side contains a black shale with source rock potential. This could be a southerly equivalent of the source rocks in the Botnheia Formation in Svalbard. The Triassic sedimentary successions in the JMM are expected to be most similar to the corresponding strata in eastern Greenland.

A regional sea-level rise and transgression began over the whole area in the Early Jurassic. That led during the Jurassic to the creation of a permanent link between the Boreal Sea to the north and the Tethys Sea to the south. Most of this period, from the Middle Jurassic and throughout the Upper Jurassic, coincided with the Kimmeridgian rift phase between Scandinavia and Greenland. That produced a landscape with the uplift of regional domes and rift-valley edges during the Middle Jurassic, followed by the collapse and inundation of the whole rift system in the Late Jurassic and Early Cretaceous. In this landscape, large delta systems developed in the Middle Jurassic and associated clastic coastal sediments were deposited to form Norway's most important reservoir rocks.

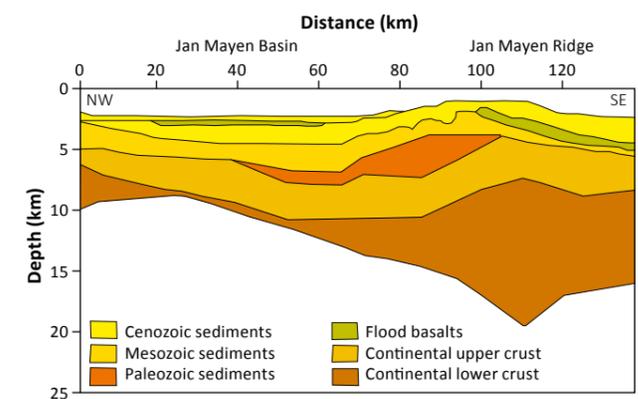


Figure 7.12 Crustal model for the JMM based on seismic (refraction) speeds measured with OBS (from Kuvaas and Kodaira, 1997, First Break 15.7).

A special feature of the Jurassic is that the succession of rock layers in the Lower and Middle Jurassic on the Halten Terrace and Trøndelag Platform are virtually identical with the succession in Greenland's Jameson Land. The Upper Cretaceous and the bottom of the Lower Cretaceous are also virtually identical, with a succession of marine shales which, in their uppermost part, comprise the most important source rocks in the North Atlantic (the Spekk Formation on the Norwegian side and the Hareelv Formation on the Greenland side). This sedimentary succession also contains strata with good reservoir rocks, sandstones alternating with shale layers (the Rogn Formation, for example, which forms the reservoir rock in the Draugen field). More sandy elements of this kind appear to exist on the Greenland side than the Norwegian. The JMM lies midway between, so that the same Jurassic sedimentary succession is expected on both sides. As on both the Norwegian and the Greenland sides, however, parts of the JMM could also have formed small land areas without deposition during the Jurassic.

During the Cretaceous, the big basins between Scandinavia and Greenland (the Møre, Vøring, Harstad and Tromsø Basins) subsided deeply, and several thousand metres of sediment were deposited. The Cretaceous sedimentary succession in the platform and terrace areas along the flanks of these basins varies in thickness from a few hundred to just over a thousand metres. The JMM was probably part of the platform area on the western side of the Møre Basin during the Cretaceous, so that thicknesses and rocks in the sedimentary succession from this period will be similar to those found on the Trøndelag Platform and Halten Terrace and in Jameson Land – in other words, moderate thicknesses of marine shales with elements of thin sandstone strata.

The area was uplifted in the Palaeocene ahead of the last phase of crustal extension and the final continental separation between Greenland and Scandinavia. A considerable amount of sand together with shale was deposited on both Norwegian and Greenland sides during this period. Both sides show a marked hiatus in the mid-Palaeocene, where much of the Palaeocene succession is eroded or not deposited. The hiatus is greatest on the Palaeocene highs. In the lower-lying areas, it narrows into the Selandian (about 60 million years ago), which accordingly appears to be the period when this uplift occurred. Thereafter the area sank again, and shallow marine sands were deposited in a number of areas. It was uplifted again before the major vulcanism which began with the actual continental separation in the early Eocene. The basaltic lavas from this process are the oldest materials so far sampled on the JMM. How much Palaeocene sand has been preserved on the JMM is uncertain. The degree to which such sand has been preserved in eastern Greenland and on the Norwegian side varies a good deal. If present, the sand lies under lava layers.

The sedimentary successions under the lava layers in the Eocene could have a big oil and gas potential, particularly if the Jurassic succession is present at a favourable depth in the sub-surface. But the JMM experienced a powerful tectonic phase in the Oligocene which did not affect the NCS. That may have caused damage to and leaks from pre-existing petroleum traps, but could also have led to the formation of new traps. Mapping this part of the sedimentary succession with the aid of seismic images has been impossible because of the overlying lava layers.

Description of plays

Plays are defined on the basis of stratigraphic levels in the sub-surface, reservoir rocks, petroleum trapping mechanisms and source rocks.

Three plays have been defined at two levels in the sub-surface on the Jan Mayen Ridge – the first two in the Eocene (east and west) and the third at a level of indeterminate age below the thick



Figure 7.13 Overview map showing the extent of the plays: east Eocene (green), west Eocene (red) and sub-basalt (green and red).

layers of basaltic lava beneath the Eocene (sub-basalt). While the strata under the lava are difficult to map, those in the Eocene show up well on the seismic images. This makes mapping much more assured. The two Eocene plays are distributed geographically on either side of the Jan Mayen Ridge, while the sub-basalt play covers the whole ridge.

Source rocks and migration

All three plays assume the migration of oil and/or gas from the same source rocks – shales in the Upper Jurassic, Middle Triassic and Middle Permian. It is uncertain how deeply these source rocks are buried or whether they are all present in the Jan Mayen Ridge. Maturation models show that, providing source rocks are available at a favourable burial depth, considerable opportunities exist for at least one to be still forming oil and/or gas. In that event, the petroleum traps in the sub-basalt play will be favourably placed for inward migration of petroleum because this level is closest to the source rock(s). Petroleum in the two Eocene plays has further to migrate because the Eocene lies higher up the succession and because the thick lava layers may act as a barrier to its ascent.

Reservoir rocks

Reservoir rocks in the Eocene plays are expected to comprise a clean, quartz-rich sandstone with good reservoir properties – in other words, high porosity and permeability. Samples of this sandstone show that it is indistinguishable from a corresponding Eocene sandstone in eastern Greenland, the Bopladsdalen Formation. It is accordingly reasonable to assume that the sandstone sampled on the Jan Mayen Ridge belongs to the same formation and is found across a wide area.

The sub-basalt play could contain sandstone reservoirs at several levels. The most probable are sandstones deposited in shallow water during the Triassic and/or Jurassic. These are expected to be

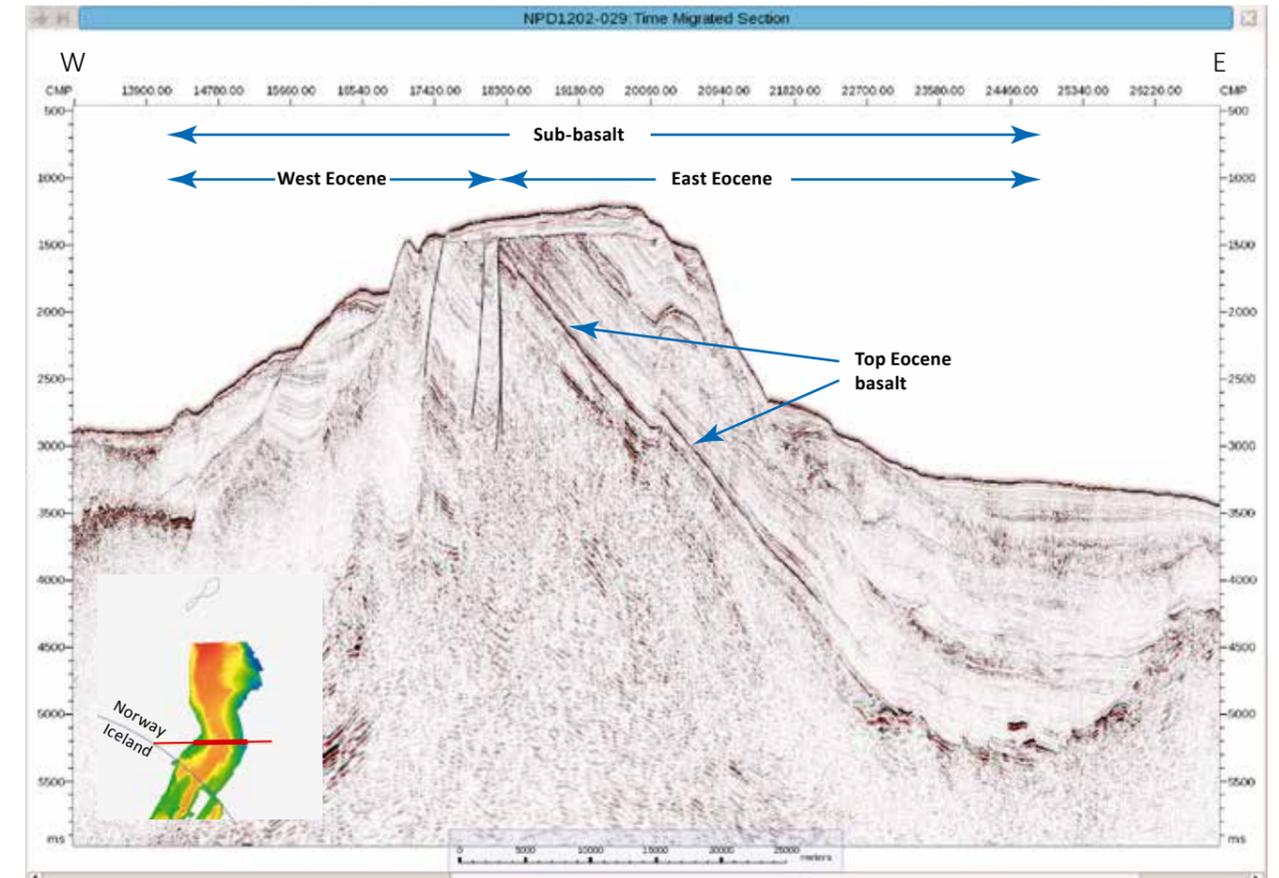


Figure 7.14 A seismic cross-section across the Jan Mayen Ridge, with the location of the plays discussed in the text marked. The location is indicated by the red line on the inset map. This also shows the water depth (red = shallow, blue = deep) and the play outlines.

equivalent to the very good reservoir rocks found at corresponding levels in Jameson Land in eastern Greenland and on the Halten Bank on the NCS.

Trap mechanisms

The two Eocene plays are distinguished from each other first and foremost by the type of trap mechanism. The traps in the west Eocene play comprise fault blocks which have been rotated and buried in tight shale. The sandstone strata are accordingly tilted and effectively sealed at the tips of the fault blocks, which provides good traps for petroleum migrating vertically. See figure 7.14. Faults forming such traps are generally distributed over the western parts of the Jan Mayen Ridge.

The eastern flank of the ridge, containing the east Eocene play, has few faults and strata slope evenly down towards the deepwater Ægir Basin to the east. Petroleum traps in this play are assumed to consist primarily of stratigraphic traps – in other words, places where the sandstone wedges out, surrounded by shale. Since the strata are sloping, such uptilted sandstone wedges will form traps sealed by the surrounding shale.

Because of the hard basalt layers, no detailed seismic image exists so far of the types of petroleum traps in the sub-basalt play. However, the faults in the strata above the lavas also run through the underlying strata and create rotated fault blocks there. Jurassic and older strata in eastern Greenland and on the Halten Bank were subject to tectonic faulting for a time before the lava layers were laid down. Rotated fault blocks are therefore likely to have formed petroleum traps throughout this play.

Resource evaluation

Methodology

Whether petroleum exists in an area is always uncertain. Calculating resources in plays takes account of this uncertainty by risk-assessing the various parameters which are significant for the presence and retention of petroleum. Plays are also defined with uncertainty distributions for different reservoir and liquid parameters.

Defining plays is a method for systematising and grouping the geological parameters which characterise the play and which distinguish it from other plays.

Results of the resource evaluation

Three plays have been defined in the Jan Mayen area. Two are in Eocene rocks (about 55-35 million years old), and one in older rocks lying beneath volcanic layers (the sub-basalt play). The two Eocene plays are distributed geographically on either side of the Jan Mayen Ridge, while the sub-basalt model covers the whole ridge (figure 7.14). The probability that all three plays have migration of oil and/or gas from the same source rock is high. An interdependence has accordingly been incorporated between the plays for the presence of source rock. In addition, an interdependence has been incorporated between the Eocene plays with regard to petroleum retention.

Expected recoverable resources from Jan Mayen are estimated at 90 million scm oe. Since mapping the strata beneath the basalt is difficult, it is very uncertain – particularly for the sub-basalt play –

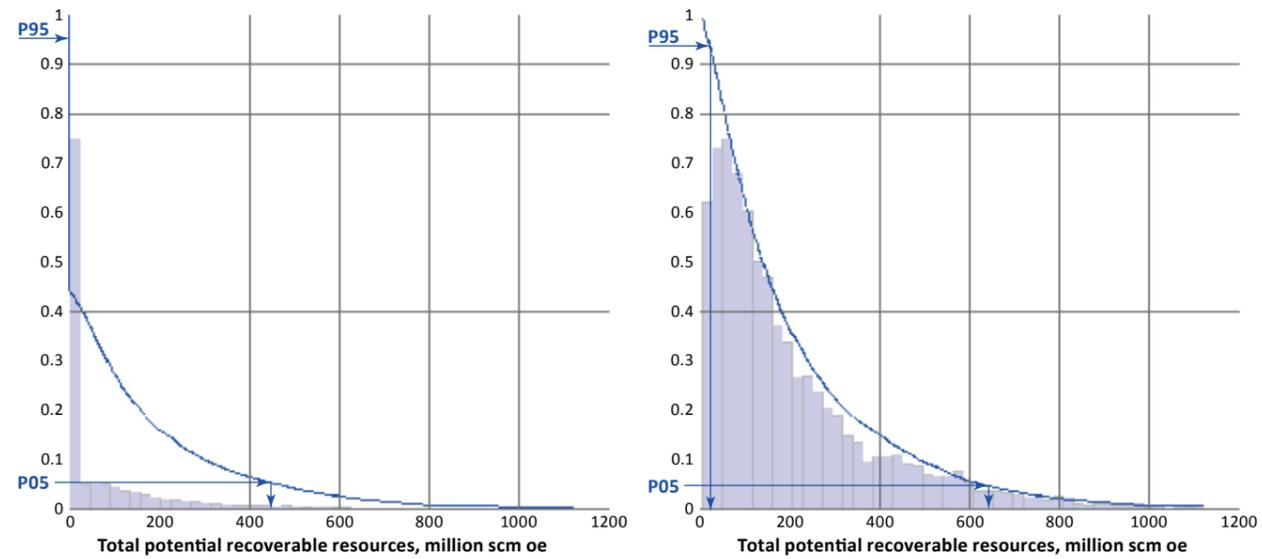


Figure 7.15 Distribution of total recoverable resources in the Jan Mayen area. The right-hand graph shows the resource distribution if at least one discovery is made which confirms at least one play.

whether petroleum is present under these plays. This uncertainty is reflected in the resource distribution, with a downside of no discoveries (0 scm oe) and an upside (P05) of 460 million scm oe (five per cent probability that the resources are equal to or greater than 460 million scm oe). See figure 7.15. The probability of making one or more discoveries is 44 per cent.

The large uncertainty range reflects the fact that none of the plays in the Jan Mayen area has been confirmed. If at least one of the plays is confirmed through drilling, expected resources in the area would rise to about 200 million scm oe (see figure 7.15), with a downside (P95) of roughly 20 million scm oe and an upside (P05) of approximately 650 million scm oe.

Figure 7.16 presents the cumulative distribution of recoverable resources for the Jan Mayen area should at least one discovery

be made which confirms at least one play. The figure shows the contributions from the various plays. It is the sub-basalt play which contributes to the high resource estimates.

Expected recoverable resources break down into about 70 million scm of liquids and roughly 20 billion scm of gas. Should at least one discovery be made which confirms at least one play, the resources break down into some 150 million scm oe of liquids and 50 billion scm of gas. See figure 7.17.

Estimates of undiscovered resources in the Jan Mayen area are very uncertain. A potential exists for oil and gas discoveries. The distribution between oil and gas is estimated to be 75 and 25 per cent respectively. A better understanding of how the plays function and a confirmation through discoveries could provide a substantial resource upside.

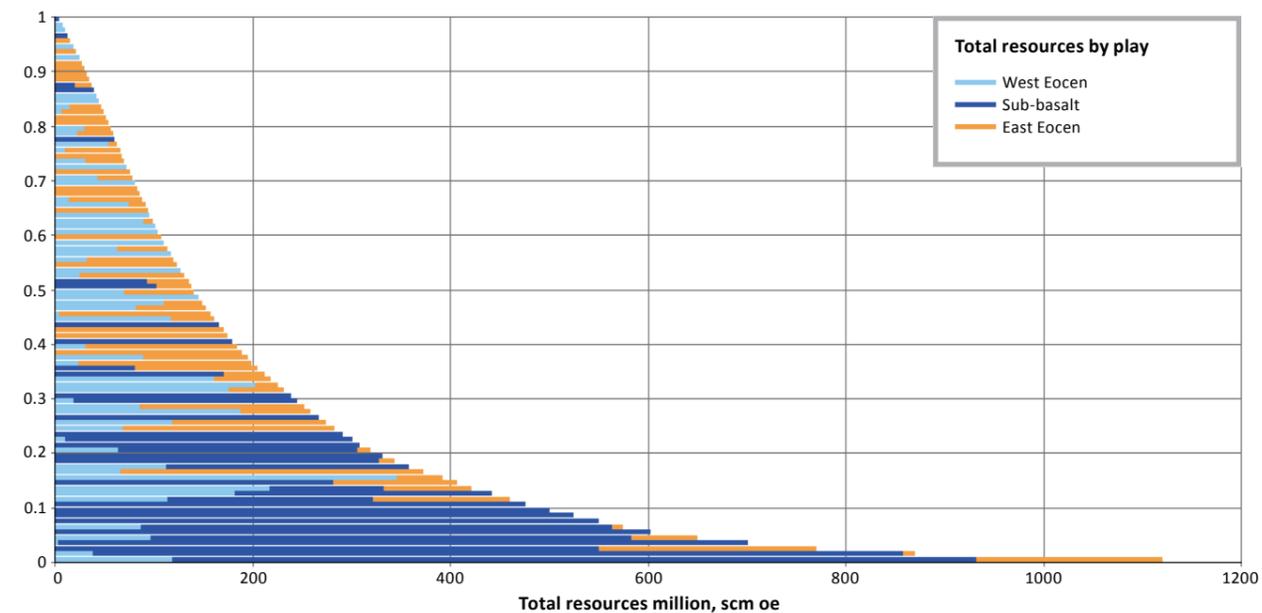


Figure 7.16 Cumulative distribution of total recoverable resources in the Jan Mayen area, showing the contributions of the various plays, assuming that at least one discovery is made which confirms at least one play.

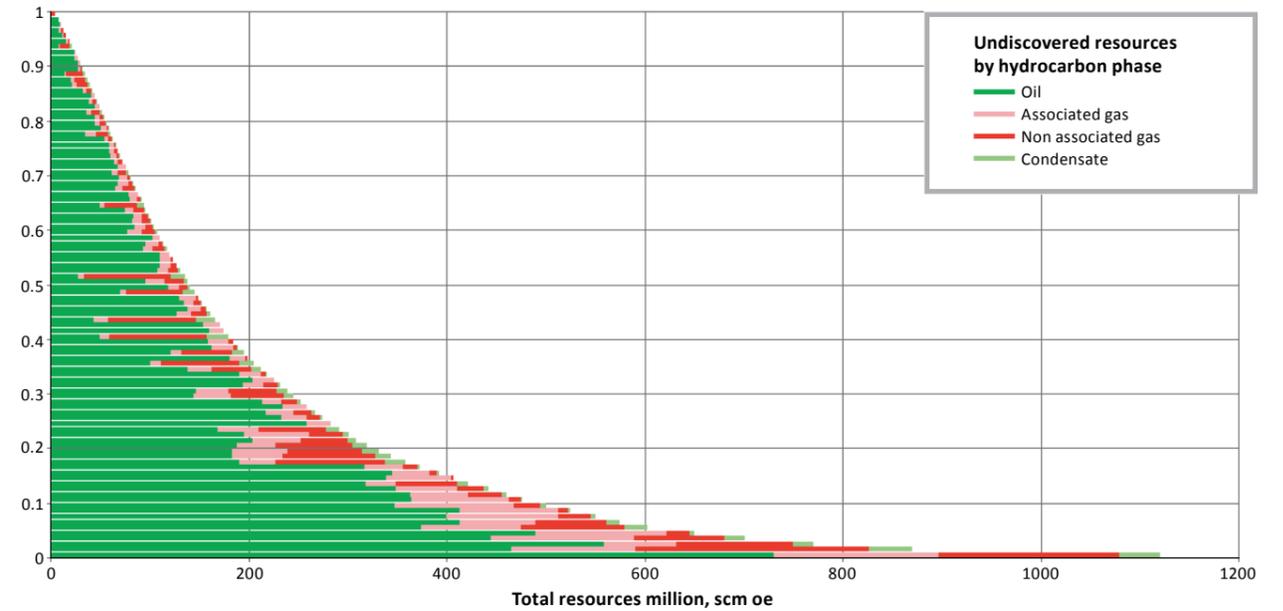


Figure 7.17 Cumulative distribution of total recoverable oil and gas resources in the Jan Mayen area, assuming that at least one discovery is made which confirms at least one play.

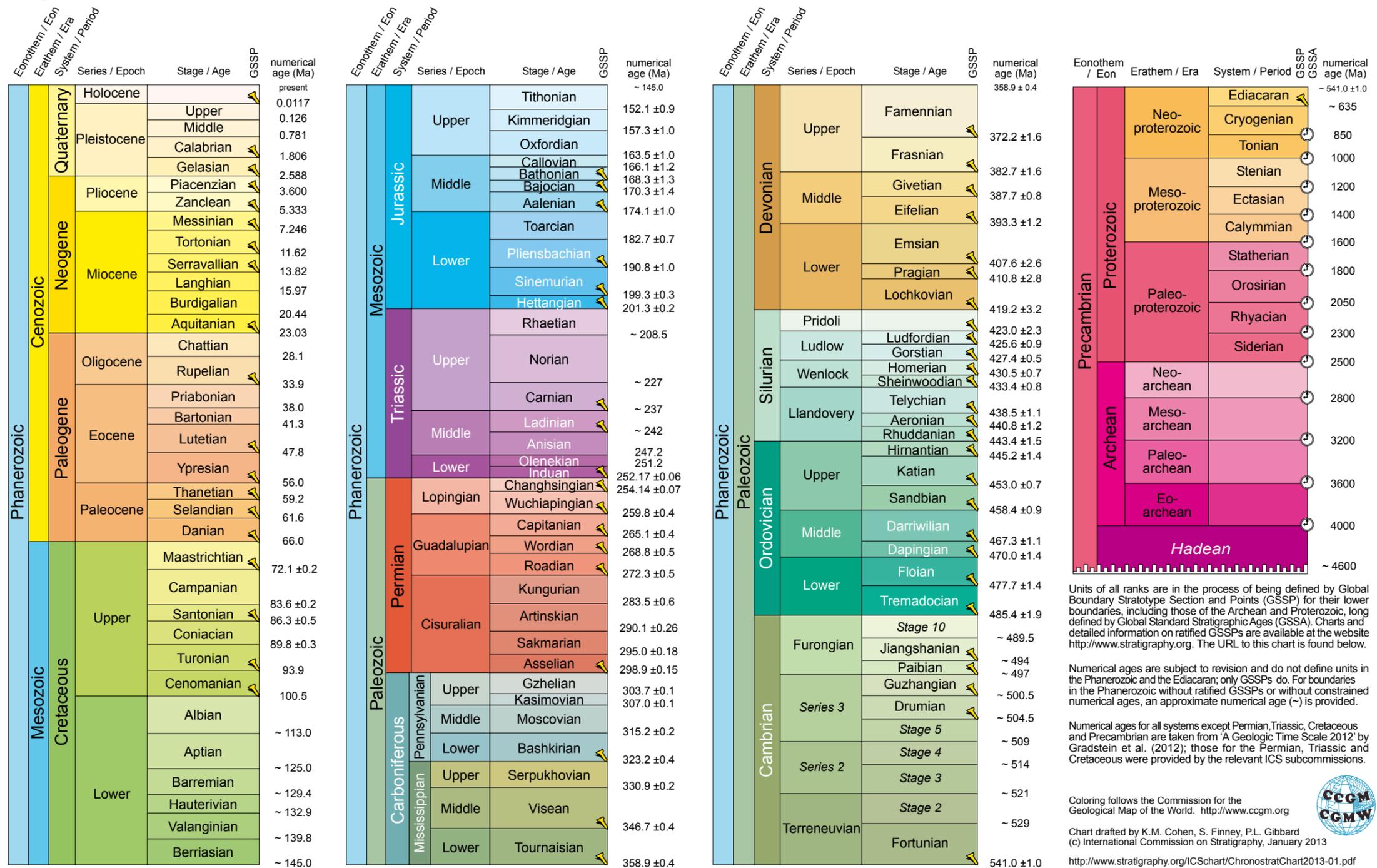


INTERNATIONAL CHRONOSTRATIGRAPHIC CHART

www.stratigraphy.org

International Commission on Stratigraphy

v 2013/01



Units of all ranks are in the process of being defined by Global Boundary Stratotype Section and Points (GSSP) for their lower boundaries, including those of the Archean and Proterozoic, long defined by Global Standard Stratigraphic Ages (GSSA). Charts and detailed information on ratified GSSPs are available at the website <http://www.stratigraphy.org>. The URL to this chart is found below.

Numerical ages are subject to revision and do not define units in the Phanerozoic and the Ediacaran; only GSSPs do. For boundaries in the Phanerozoic without ratified GSSPs or without constrained numerical ages, an approximate numerical age (~) is provided.

Numerical ages for all systems except Permian, Triassic, Cretaceous and Precambrian are taken from 'A Geologic Time Scale 2012' by Gradstein et al. (2012); those for the Permian, Triassic and Cretaceous were provided by the relevant ICS subcommissions.

Coloring follows the Commission for the Geological Map of the World. <http://www.ccgw.org>

Chart drafted by K.M. Cohen, S. Finney, P.L. Gibbard (c) International Commission on Stratigraphy, January 2013 <http://www.stratigraphy.org/ICSchart/ChronostratChart2013-01.pdf>



Conversion tables

	1 scm of oil	=	1 scm oe
	1 scm of condensate	=	1 scm oe
	1 000 scm of gas	=	1 scm oe
	1 tonne of NGL	=	1.9 scm of NGL = 1.9 scm oe
Gas	1 cubic foot		1 000 British thermal unit (Btu)
	1 cubic metre		9 000 kcal
	1 cubic metre		35.3 cubic feet
Crude oil	1 scm		6.29 barrels
	1 scm		0.84 tonnes oe (toe)
	1 tonne		7.49 barrels
	1 barrel		159 litres
	1 barrel/day		48.8 tonnes/year
	1 barrel/day		58 scm /year

	MJ	kWh	TCE	TOE	Scm natural gas	Barrel crude oil
1 MJ, megajoule	1	0.278	0.0000341	0.0000236	0.0281	0.000176
1 kWh, kilowatt hour	3.60	1	0.000123	0.000085	0.0927	0.000635
1 TCE, tonne coal equivalent	29 300	8 140	1	0.69	825	5.18
1 TOE, tonne oil equivalent	42 300	11 788	1.44	1	1 190	7.49
1 scm natural gas	40.00	9.87	0.00121	0.00084	1	0.00629
1 barrel crude oil (159 litres)	5 650	1 569	0.193	0.134	159	1

See also the dictionary on the NPD website at <http://www.npd.no/en/About-us/Information-services/Dictionary/>



Design of the resource report

The design elements in this report are based on microscope photos of such microorganisms as dinoflagellates and bolboforma from the NPD's collections.

Basically yellow and white in colour, these organisms are 95-10 million years old.

They have been adapted by architects Liv-Kristine Ruud and Agnes Selheim in connection with a decorative assignment for the NPD.