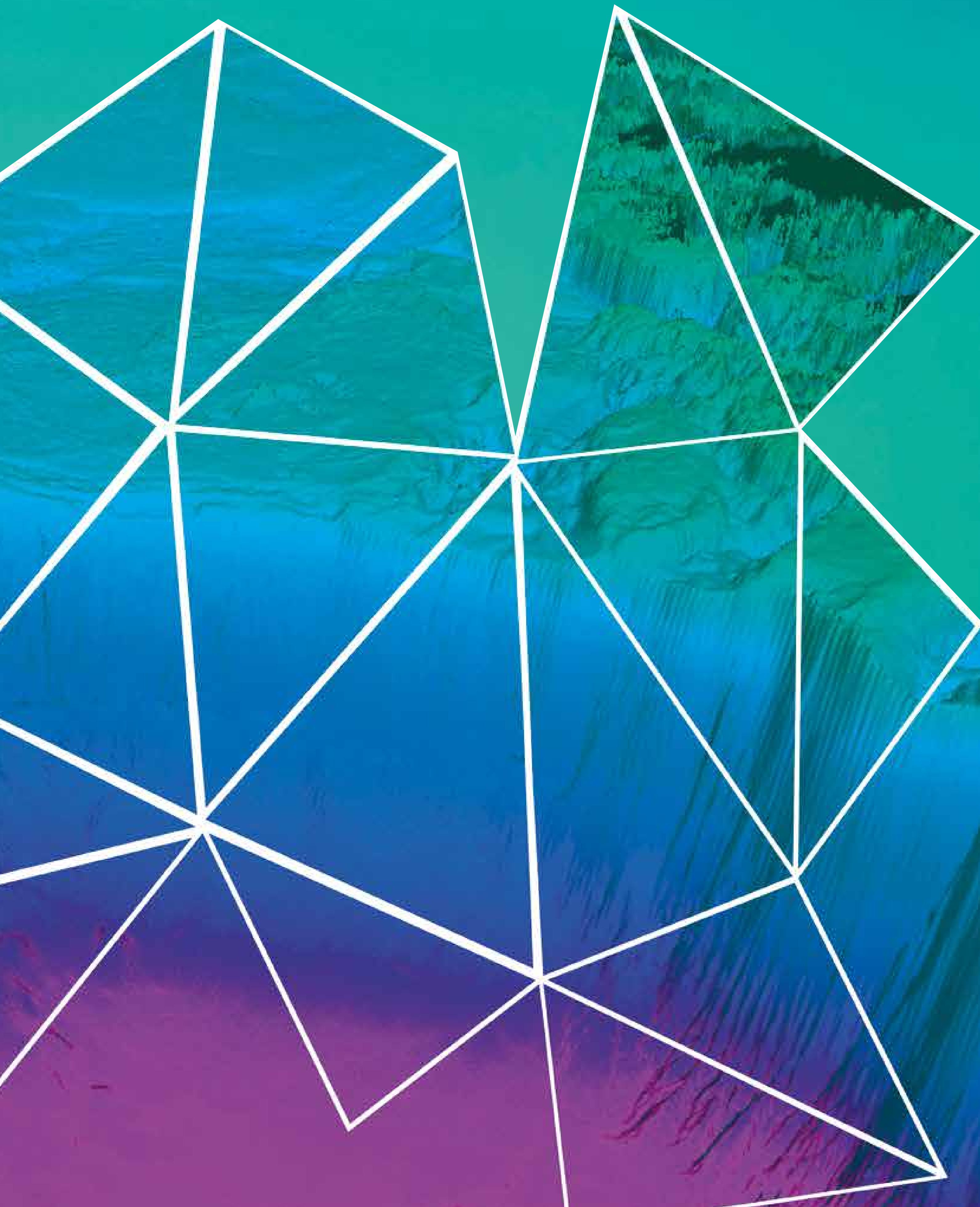
NORWEGIAN PETROLEUM
DIRECTORATE

RESOURCE REPORT
EXPLORATION 2018



CONTENTS

FOREWORD

Production of oil and gas from the Norwegian continental shelf (NCS) is expected to rise over the next few years. This increase reflects contributions from discoveries under development as well as output growth from fields already on stream. Production from these sources will begin to decline from the mid-2020s, and resources which have still to be discovered will start making their mark. Several years pass between a discovery and bringing it on stream, so making new and large discoveries quickly is necessary for maintaining production at the same level from the mid-2020s.

The main job of the Norwegian Petroleum Directorate (NPD) is to contribute to securing the greatest possible value for society from oil and gas operations through efficient and prudent resource management, which takes account of health, safety, the environment and other users of the sea. A good factual and knowledge basis is a prerequisite for the government to play a decisive role in resource management.

In this report, the NPD presents an updated overview of the undiscovered petroleum resources on the NCS. It shows that roughly 55 per cent of expected oil and gas resources remain to be produced after more than 50 years of activity, and that just under half of these are still to be discovered.

The NPD's updated estimate for undiscovered resources is 4 000 million standard cubic metres of oil equivalent (scm oe). That represents an increase of almost 40 per cent from the previous figure in 2016. The big growth results from the NPD's mapping of resources northwards in the Barents Sea close to the boundary with the Russian sector. Estimated undiscovered resources in the open part of the Barents Sea, the North Sea and the Norwegian Sea are more or less unchanged. Almost two-thirds of the undiscovered resources lie in the Barents Sea, with the rest shared between the Norwegian and North Seas. The upside potential is greatest in the Barents Sea, where large areas remain to be explored.

These figures reveal that opportunities on the NCS are still substantial and can provide the basis for oil and gas production over many decades. The government provides a steady supply of exploration acreage through regular licensing rounds, contributing to important predictability for the sector. Significant interest has been shown by the industry in the latest licensing rounds and, after a couple of years with lower exploration drilling, activity has started rising again. This is important for ensuring that the resource potential gets proven and produced.

Discoveries in recent years have been smaller than before. In areas with existing infrastructure, even very small finds can be tied back to existing fields and contribute to substantial value creation. The NPD's analyses show that exploration has been profitable in all parts of the NCS. Continuing to explore actively in both known and less familiar areas will therefore be important. A diverse range of players contributes to this.

Finding oil and gas deposits is becoming increasingly difficult. Technological advances have provided better data and improved tools, contributing to new understanding and making it possible to identify new play and prospect concepts. This trend will continue in coming years. Integration of broad and deep geoscientific expertise and digital technology will probably be the key to identifying new resources in coming years.

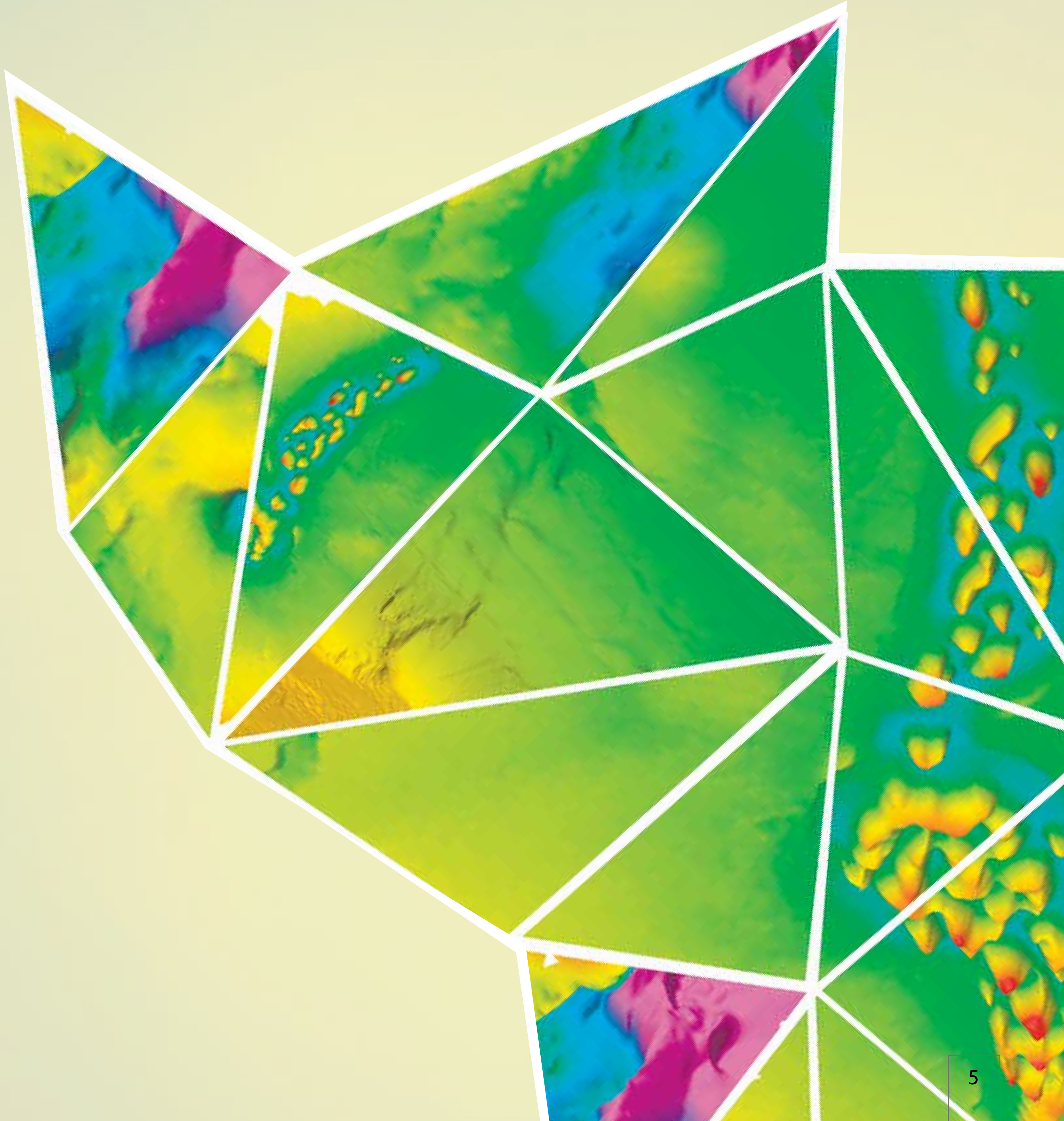
This report collates information and presents a number of analyses which will form part of the knowledge base for both government and industry. These analyses are intended to provide the basis for learning and for good exploration decisions, which can help to maintain exploration and the level of production in the future.

Deposits of minerals with rare earth elements are found on the seabed in many parts of the world, and interest in the commercial exploitation of such resources is dawning. On the NCS, seabed minerals are known to exist in the deep parts of the Norwegian Sea. The NPD is due to launch its own investigations in the summer of 2018. This might become a new chapter in the history of Norway's marine resources.

Stavanger, June 2018

Torgeir Stordal
Director exploration

CHAPTER 1
INTRODUCTION AND SUMMARY



Substantial remaining resources on the Norwegian continental shelf (NCS) continue to offer big opportunities in both mature and less-explored areas. Increased knowledge, better data coverage, new working methods and innovative technology open new exploration opportunities and can yield a number of commercial discoveries. The companies must explore and discover more in order to maintain activity and production over time.

Next year will be the 50th anniversary of the Ekofisk discovery in the southern part of the NCS. This event generated great interest in exploring off Norway, and a number of substantial discoveries were made over the next 20 years. About 70 per cent of proven resources were found in the period up to 1990 (figure 1.1).

Since the first commercial oil discoveries were made, Norway has established itself as an important player in international oil and gas markets.

SUBSTANTIAL VALUE

Oil and gas from the NCS have generated massive revenues to help make Norway a very wealthy country today. The petroleum sector is the country's largest industry measured by value creation, government revenues, investment and export value.

Petroleum operations accounted in 2017 for about 14 per cent of Norway's gross domestic product (figure 1.2). They were responsible for 19 per cent of total investment and 17 per cent of government revenues. Sales of oil and natural gas provided some 40 per cent of total Norwegian export value in 2017.

PURPOSEFUL MEASURES

Exploration activity measured by annual exploration wells has fluctuated partly in line with oil price trends (figure 1.3). It declined from the 1990s to bottom out in 2005 at 12 wells. That prompted the government to adopt purposeful measures aimed at stimulating activity while increasing diversity and competition on the NCS. Combined with rising oil prices, these measures led to a sharp increase in exploration wells. New companies entered and a number of commercial discoveries were made, with 16/2-6 Johan Sverdrup as the largest.

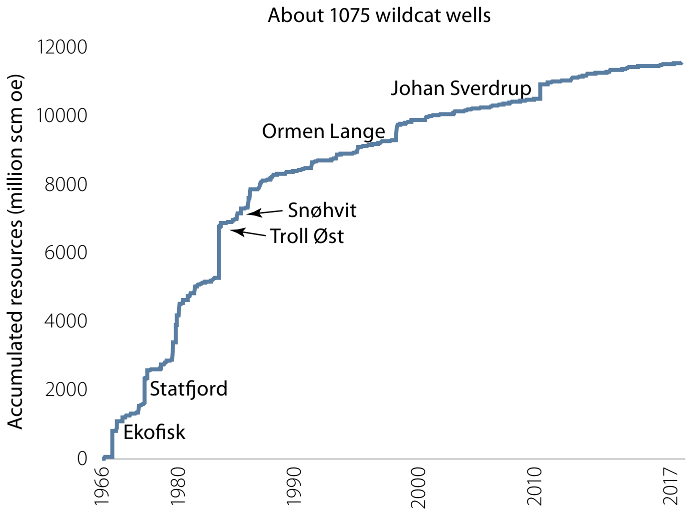


Figure 1.1 *Resource growth on the NCS 1966-2017.*

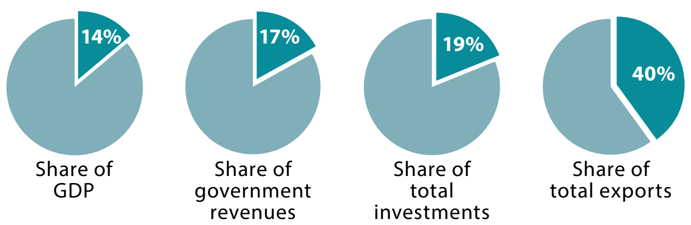


Figure 1.2 *Macroeconomic indicators for the petroleum sector 2017.*

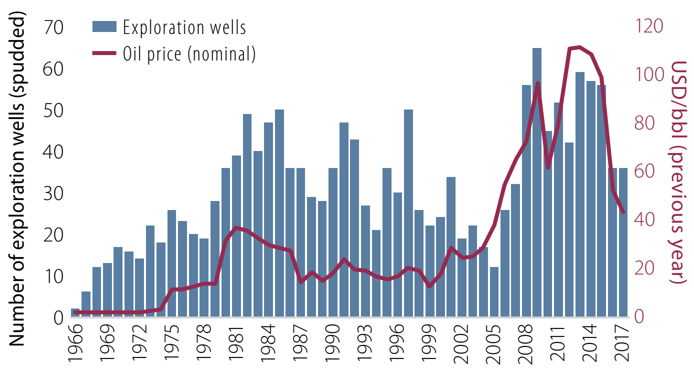


Figure 1.3 *Developments in exploration wells spudded.*

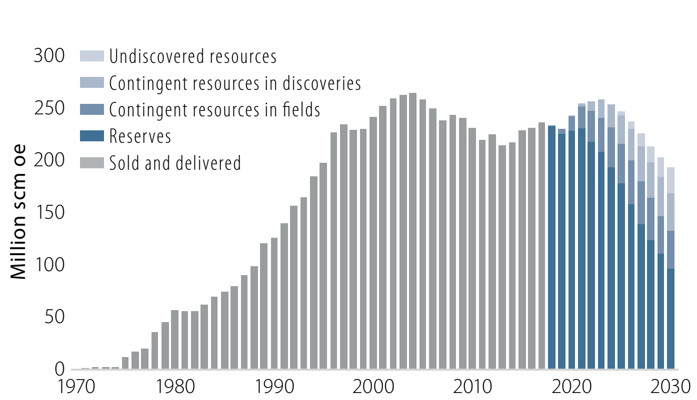


Figure 1.4 *Historical and expected future production from the NCS to 2030.*

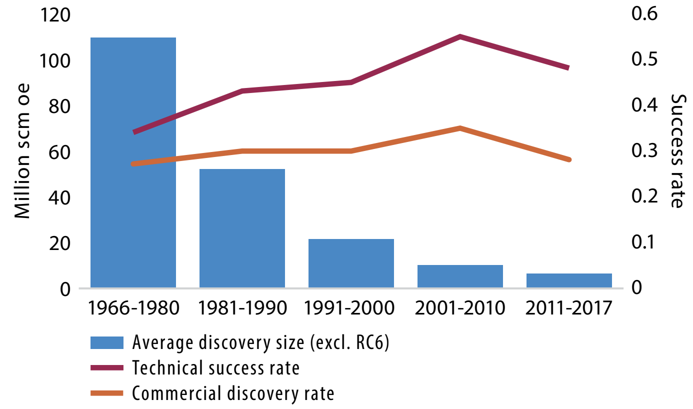


Figure 1.5 *Development of average discovery size and average technical and commercial success rates.*[1] *Discovery size is based on today's estimate, not that reported at the time of discovery.*

SOFT LANDING

After a sharp growth in wells and spending during 2005-14, the level of costs and the oil price slump in the late autumn of 2014 led to cuts in exploration budgets, postponed investment and fewer exploration wells. Their number declined from 57 in 2014 to 36 in 2016. Measures were also adopted by the industry to enhance productivity and efficiency while cutting costs. The decline flattened out in 2017, and exploration in 2018 is expected to be higher than in the two preceding years. Activity remains relatively high in a historical perspective.

SUBSTANTIAL RESOURCE POTENTIAL

Despite more than 50 years of exploration, the NPD's assessment is that big opportunities still exist on the NCS. The resource accounts indicate that about half of Norway's total petroleum resources are left to produce. Roughly 53 per cent of the expected remaining resources lie in fields and discoveries, while 47 per cent remain to be found.

The NPD's updated mapping has led it to raise its estimate of undiscovered resources from around 2 900 standard cubic metres of oil equivalent (scm oe) to 4 000 million. Considerable uncertainty attaches to this estimate, particularly for the little-explored areas in the Barents Sea and around Jan Mayen.

Total remaining resources provide the basis for petroleum production over many decades to come. Today's forecast for future oil and gas output shows an increase until the mid-2020s, followed by a gradual decline. From around 2025, a steadily larger proportion of production must come from as yet undiscovered resources (figure 1.4). If production and the level of activity are to be maintained at current levels, therefore, more exploration is needed and new resources must be proven.

DEVELOPMENT FEATURES

Discoveries are smaller. On average, discoveries in recent years have been smaller than before (figure 1.5) – a natural development in a mature petroleum province. Mature areas are characterised by known geology, normally fewer and smaller technical challenges, and well-developed or planned infrastructure. The bulk of the acreage opened for petroleum operations is now mature. Big undiscovered resources remain in mature areas, which could provide the basis for new finds. These resources could represent substantial value.

The trend for the technical success rate shows that increased knowledge, more and better data, and technological progress have helped to make exploration more efficient since the first well in 1966. Despite some decline for the average success rate in recent years, it has remained at a high level from the 1990s. The commercial success rate has remained more or less unchanged since petroleum operations began, even though the average discovery size has been declining. Exploration on the NCS remains profitable.

[1] Discoveries not very likely to be recovered – resource class 6 (RC6) – are not included when calculating average discovery size. All discoveries are included in calculating the technical discovery rate. The commercial discovery rate excludes discoveries in RC6. An estimated assessment has also been made for new discoveries in resource class 7 (RC7) – in other words, those which have not been evaluated. See figure 1.10 for the NPD's resource classification system.

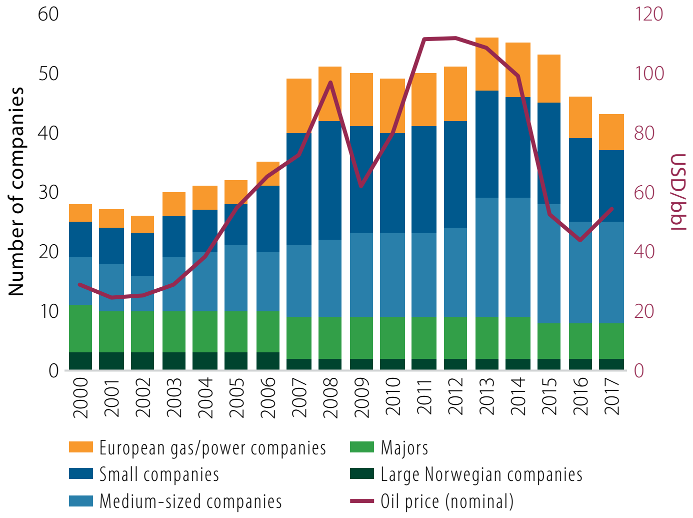


Figure 1.6 *Players on the NCS by size, 2000-17.*

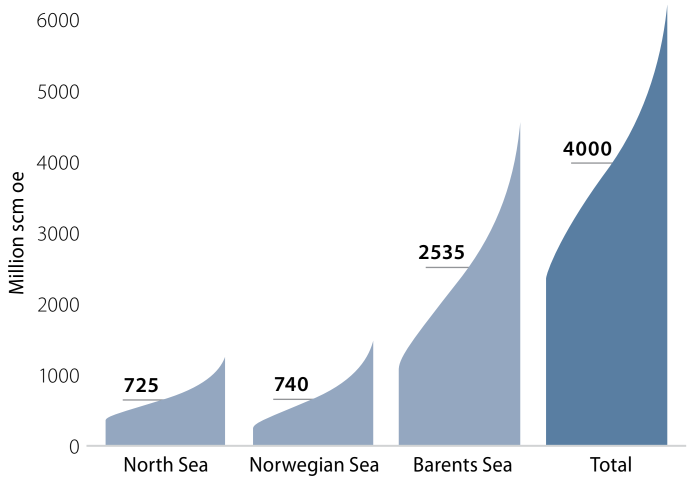


Figure 1.7 *Estimated undiscovered resources by area.*

Even very small discoveries can become commercial when they are phased in to existing fields or developed in coordination with other finds. Coordinated development of several discoveries normally reduces unit costs and lowers the threshold for exploration and development. Achieving commercial production from smaller finds located far from existing infrastructure is more demanding.

Diversity creates competition. A broad variety of companies, both large and small, creates competition which encourages efficiency and a diversity of ideas in the exploration phase.[2] The number of players on the NCS has increased from the mid-2000s, partly as a result of measures to create greater diversity. Although the total has declined somewhat since 2013, variety remains high (figure 1.6).

A trend in recent years has been that the majors are exploring less actively and cutting back on or withdrawing from the NCS. This can be viewed in relation to such factors as the fall in oil prices and a decline in expected discovery size. When the large companies reduce their exploration activity, the medium-sized and small players become increasingly important. Maintaining a positive combination of active and experienced large and medium-sized companies, more focused exploration companies and new company creations for both exploration and production is important for continued efficient exploration of the NCS.

Most and biggest in the far north. Most of the undiscovered resources are expected to lie in the Barents Sea (figure 1.7). Opportunities for making big discoveries are greatest in little-explored areas. New discoveries in the Barents Sea will be increasingly important as production further south on the NCS begins to decline from around 2025.

Half the undiscovered resources in the Barents Sea lie in unopened areas of the far north. The NPD's mapping of parts of these areas has identified big structures which could contain large quantities of oil and gas (figure 1.8).

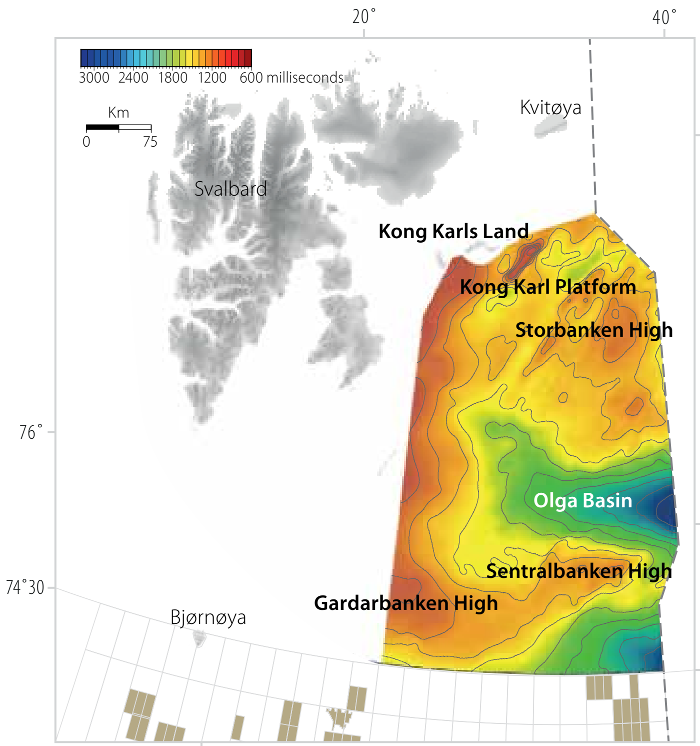


Figure 1.8 *Large structures and the extent of the mapped area in Barents Sea North (time contour map for the top of the Permian).*[3]

Resources are harder to find – calls for technology and expertise. Finding new petroleum resources is becoming increasingly difficult in areas with a long exploration history. Exploration takes place to a great extent in areas which have been open to oil and gas activities for many years, so additional data must be acquired or existing information reanalysed to obtain new understanding. Seismic surveys and data from exploration wells are the geologists' most important basis for establishing new plays. Technological advances have provided new and better tools which contribute to steady improvements in understanding the sub-surface.

Collating and integrating all available data are also very important for making new discoveries. Expertise and experience are crucial here. In a long-term perspective, therefore, it is a matter of concern that applications to study traditional petroleum subjects have declined substantially in recent years in line with cost cuts and downsizing by the companies.

Gas calls for collaboration and a joint effort. Gas accounts for roughly half the undiscovered resources. Since the average discovery size is declining, many small gas finds are likely in the opened areas. The infrastructure in the North and Norwegian Seas is well developed (figure 1.9). As more spare capacity becomes available, interest among the companies in also exploring for small gas deposits could increase.

Almost two-thirds of the undiscovered gas is expected to lie in the Barents Sea. That emphasises the significance of this area for long-term output. Current gas transport capacity from the Barents Sea is limited to the liquefaction plant at Melkøya. Under existing plans, capacity there will be fully utilised until the early 2040s. Lack of infrastructure and spare gas transport capacity affects exploration. Where the companies are concerned, finding gas which does not

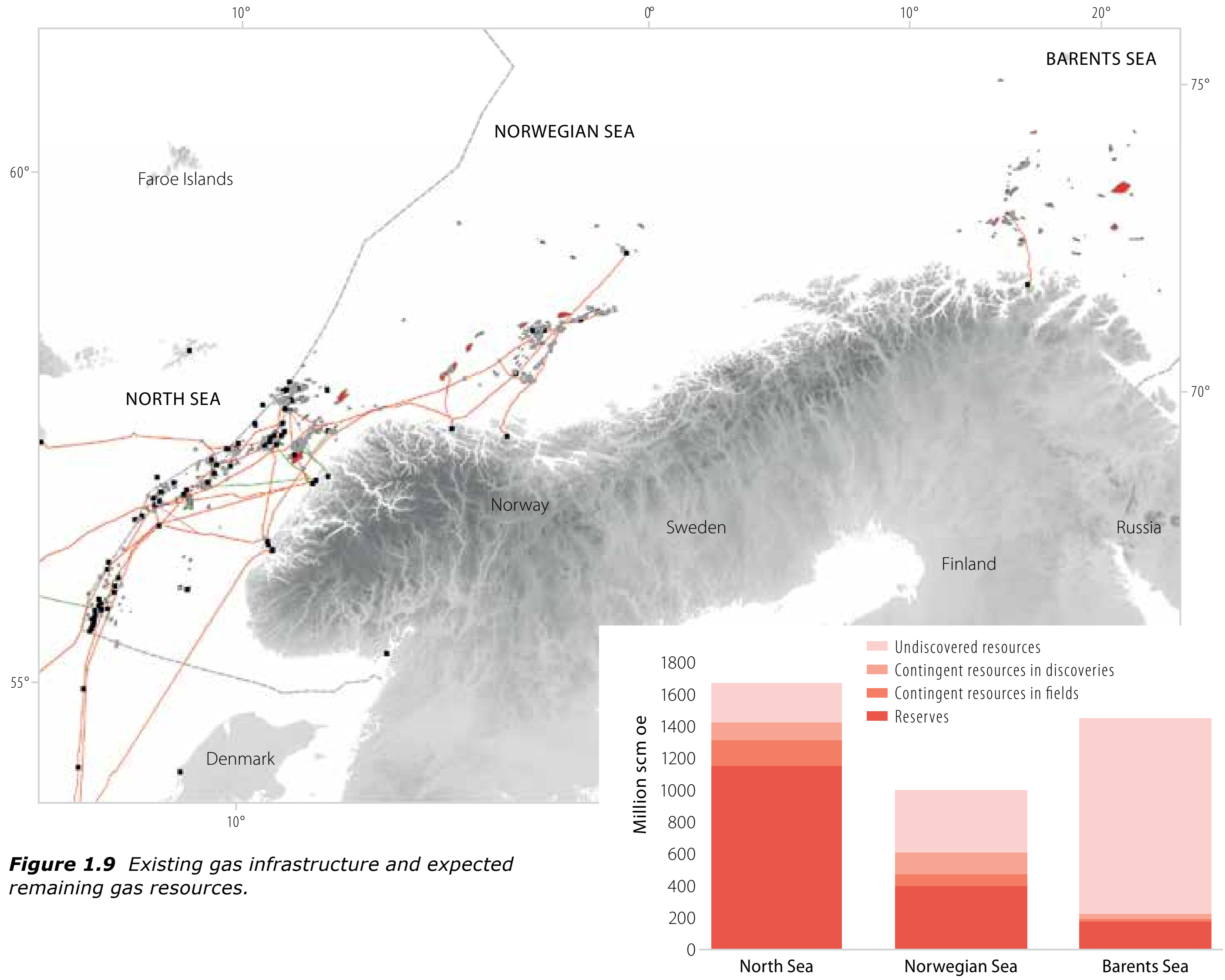


Figure 1.9 *Existing gas infrastructure and expected remaining gas resources.*

[2] See the resource report for 2017 at *www.npd.no* for analyses of the player picture in the development and operation phases.

[3] The NPD's report on *Geological assessment of petroleum resources in eastern parts of Barents Sea North 2017.*

justify an independent export solution is of little value. Gas discoveries in the Barents Sea therefore depend to a greater extent on unitisation and coordinated development. At the same time, it will be more difficult to discover sufficient gas resources which can support new infrastructure unless the companies explore for them.

HARD WORK AND INTELLIGENT CHOICES
Substantial opportunities remain on the NCS. More than half the expected resources are still in the ground, and half of these are yet to be discovered. Innovative technology and better-quality data open new opportunities, including in mature areas. Spare capacity in existing infrastructure as well as cuts in exploration and development costs have lowered the threshold with regard to exploring for and producing small discoveries.

Bigger finds are also needed if production is to be sustained. Relatively large discoveries are still possible in known and mature areas. However, the potential for making large finds which can support new infrastructure and contribute to a high level of production is greatest in little-explored areas – and particularly areas which have still to be opened.

But resource opportunities will not just happen. Hard work and intelligent choices are needed to ensure that resources in both mature and less-explored areas contribute to maintaining production and creating value.

SUMMARY

CHAPTER 2: **EXPLORATION ON THE NCS**
Trends for exploration on the NCS and in its various sea areas are presented. After a number of years with a high level of activity, exploration declined from 56 wells in 2015 to 36 in 2016 and 2017. However, 40-50 exploration wells are expected in 2018.

Substantial interest has been shown in new exploration acreage during the latest licensing rounds. This probably partly reflects new understanding based on better seismic data and well results which have led to new play and prospect concepts. Cost cuts and access to infrastructure capacity are other important factors.

On average, discoveries in recent years are smaller than before. Smaller finds and fewer wells will make it demanding to maintain production over time. The number of wells drilled and the size of discoveries made must be above the average for the past decade if production is to be sustained at a high level. Opportunities for making larger finds are probably greatest in less-explored areas.

CHAPTER 3: **UNDISCOVERED RESOURCES**
Total undiscovered resources are estimated to lie between 2 330 (P95) and 6 200 (P05) million scm oe. The expected value is 4 000 million scm oe, up by 37 per cent from 2 920 million scm oe in 2015. This increase primarily reflects a new estimate for Barents Sea North in 2017. The NPD's mapping there has identified large structures which could yield substantial oil and gas discoveries. The updated estimate for undiscovered resources shows that the total amount remaining could provide the basis for oil and gas production over many decades to come.

CHAPTER 4: **PROFITABILITY OF EXPLORATION**
Exploration in the past decade has contributed substantial value to society. The net present value of this activity over these 10 years, at discount rates of four and seven per cent, was about NOK 930 billion and NOK 560 billion respectively. Exploration has been profitable in all areas.

CHAPTER 5: **PLAYER PICTURE IN THE EXPLORATION PHASE**
A broad variety of companies creates competition, which promotes efficiency and value creation in the exploration phase. That contributes to greater diversity of ideas and interest in different plays, technologies, and play and prospect concepts. The number of players on the NCS has increased from the mid-2000s, partly as a result of measures to create greater diversity. Although their total has declined somewhat since 2013, variety remains high.

CHAPTER 6: **NEW EXPLORATION TECHNOLOGY AND WORK PROCESSES**
In order to understand better how progress with technology and geological methods has contributed to efficient exploration, the NPD carried out a study in collaboration with consultant Westwood Global Energy Group. This identified a number of areas within a wider exploration technology concept, such as data acquisition, geosciences and working methods, which have either been or are expected to become important for exploration on the NCS.

CHAPTER 7: **EXPLORATION LOOK-BACK ANALYSES**
Earlier NPD analyses have shown that the companies exaggerate resource expectations and understate the probability of success in drilling. This means their exploration portfolios systematically deliver below expectations.

The industry has long worked purposefully to avoid biases in the decision basis, but a number of analyses show that an improvement potential still exists. That finding is underlined by the NPD analyses presented in this chapter.

CHAPTER 8: **RESOURCES FOR THE FUTURE: SEABED MINERALS AND GAS HYDRATES**
The greater attention being paid to producing energy with a low carbon footprint is expected to mean an increased need for natural gas and a growing demand for metals and rare-earth elements (REEs).

On the NCS, seabed minerals are known to exist in the deep parts of the Norwegian Sea. Mapping has identified both manganese crusts and sulphides.

Gas hydrates could become a future energy source. These are found in large quantities immediately beneath the seabed in some parts of the Norwegian and Barents Seas. No solution currently exists for profitable production of such deposits, but research on recovery methods is under way internationally.

RESOURCE CLASSIFICATION AND RESOURCE ACCOUNTS AT 31 DECEMBER 2017

THE NPD'S RESOURCE CLASSIFICATION SYSTEM
Petroleum resources are divided into classes which reflect the level of knowledge about the quantities involved and the maturity of development projects. These classes correspond to a great extent with those used in internationally recognised classification systems.

The resource classes are:
- reserves
- contingent resources
- undiscovered resources.

Reserves and contingent resources represent total discovered recoverable resources. They are broken down in turn into sub-classes which reflect their status before and after important decision gates in the process of maturing projects up to development and recovery (production).

Undiscovered resources are broken down into estimated but unproven petroleum resources in mapped prospects and estimated but unproven recoverable petroleum resources related to plays (fact box 3.2).

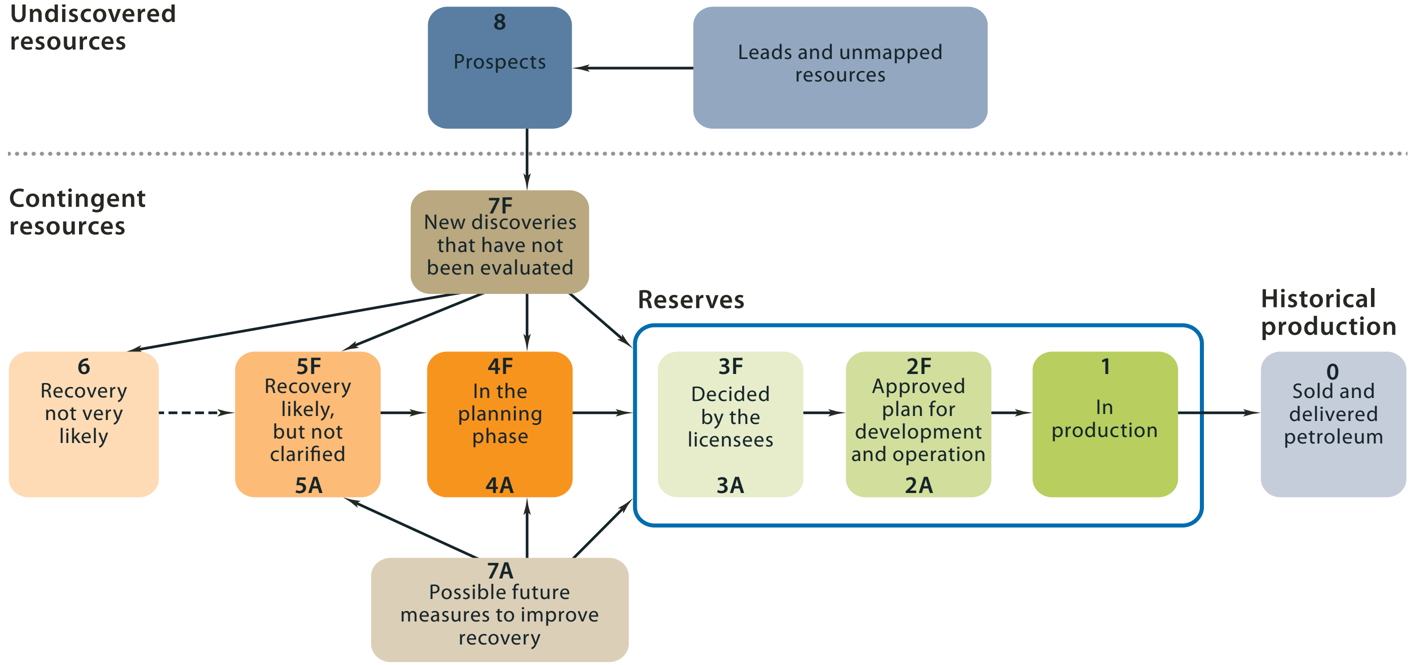


Figure 1.10 *The NPD's resource classification system (www.npd.no).*

RESOURCE ACCOUNTS AT 31 DECEMBER 2017

The NPD's estimate for total proven and unproven petroleum resources on the NCS is about 15.6 billion scm oe. Of this, 7.1 billion or 45 per cent have been sold and delivered (table 1.1).

The amount remaining to be produced is estimated at 8.5 billion scm oe. Proven resources account for 4.5 billion of this. Estimated unproven resources come to four billion scm oe, or about 47 per cent of remaining resources.

Total petroleum resources on the Norwegian continental shelf at 31 December 2017

	Oil mill scm	Gas bn scm	NGL mill tonnes	Condensate mill scm	Total mill scm oe
Produced	4 261.4	2 341.1	200.3	117.3	7 100.3
Reserves*	1 131.1	1 729.1	109.5	20.7	3 088.9
Contingent resources in fields	338.2	241.3	20.8	2.4	621.5
Contingent resources in discoveries	275.0	293.4	15.2	1.9	599.2
Production not evaluated (RC7A)	130.0	70.0			200.0
Undiscovered resources	1 995.0	1 870.0		135.0	4 000.0
Total	**8 130.7**	**6 544.9**	**345.8**	**277.4**	**15 610.0**

* Includes resource classes 1, 2 and 3

Table 1.1 *Total petroleum resources on the NCS at 31 December 2017.*[4]

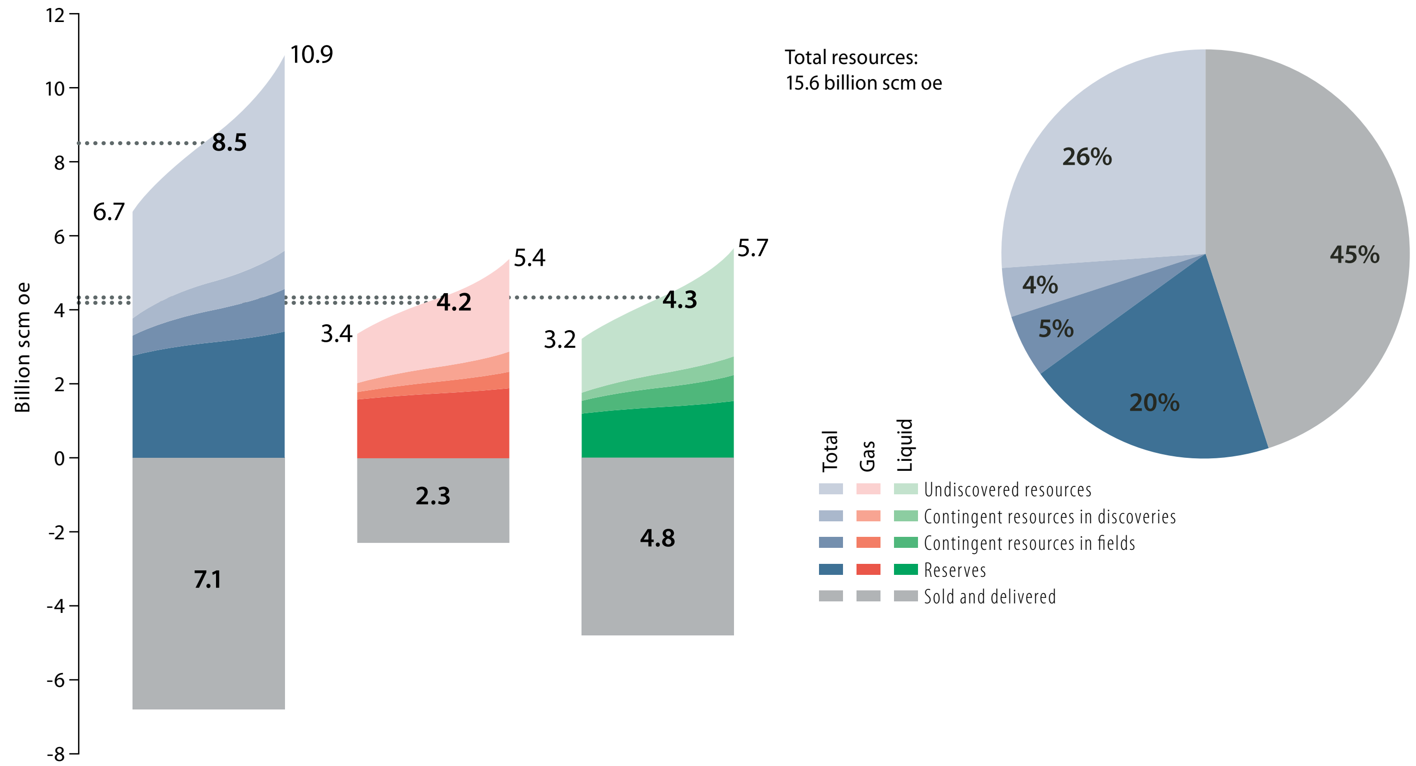
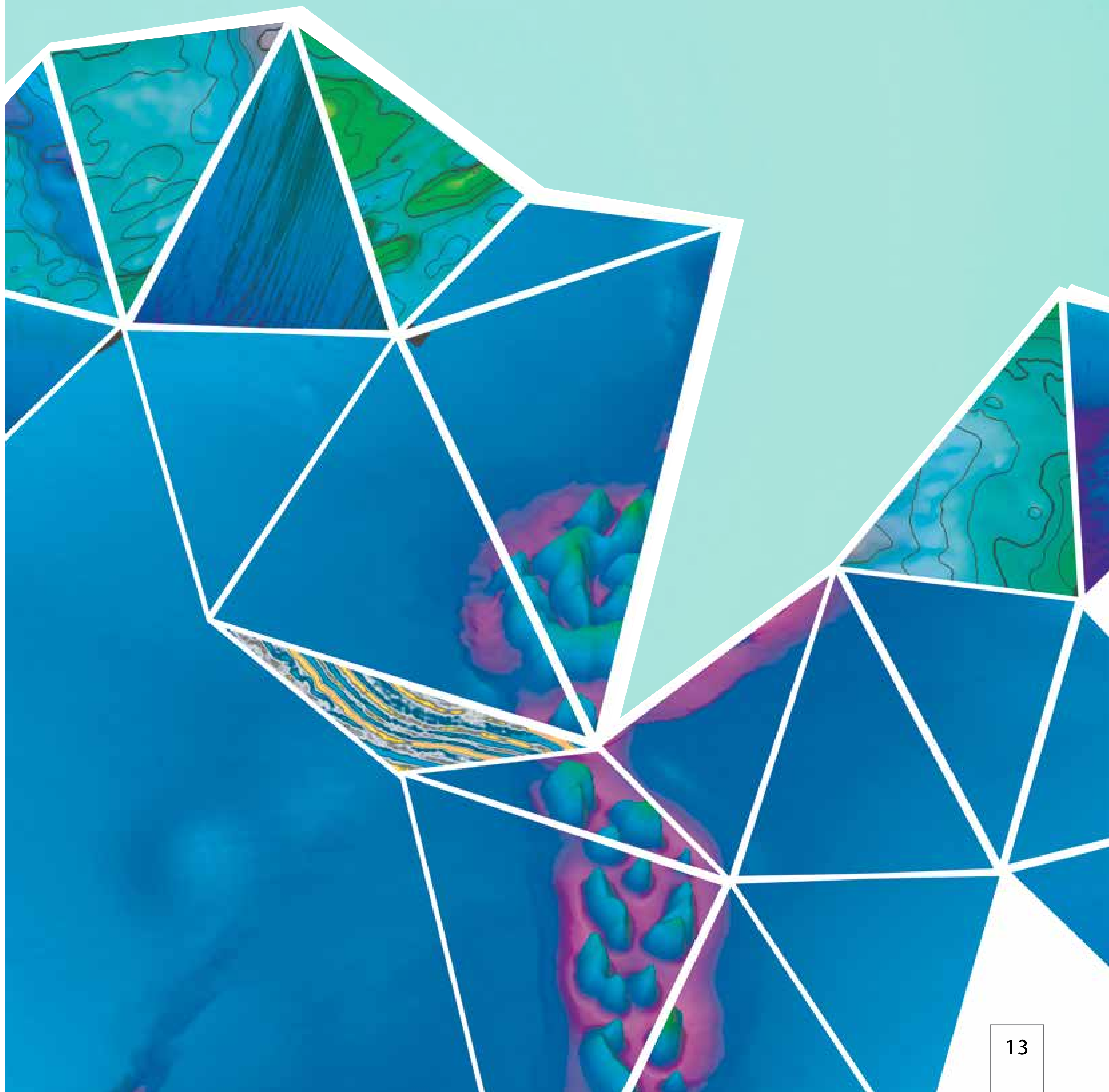


Figure 1.11 *Petroleum resources and uncertainty in the estimates at 31 December 2017.*

[4] Oil and condensate are specified in million scm, natural gas liquids (NGL) in million tonnes, and gas in billion scm. The conversion factor from tonnes to scm for NGL is 1.9. Total oil equivalent is specified in million scm oe.

CHAPTER 2
EXPLORATION ON THE NCS

The companies must explore and make larger discoveries in order to maintain production on the Norwegian continental shelf at a high level.



The government provides a steady supply of exploration acreage through regular licensing rounds. Great interest has been shown by the industry in the most recent of these. After a couple of years with reduced activity, the number of exploration wells is rising again. It is important that the industry maintains a high level of exploration.

Exploration is influenced by such factors as expected prospectivity, available acreage, the regulatory framework, costs and the level of oil and gas prices. A long-running increase in activity which began in 2006 ended in 2016 after a substantial drop in oil prices. While 56 exploration wells were drilled in 2015, the annual figure for 2016 and 2017 was 36. However, 40-50 are expected in 2018.

Substantial interest has been shown in new exploration acreage during the most recent licensing rounds. This partly reflects new understanding based on better seismic data and well results, which have led to new play and prospect concepts. Cost cuts and access to infrastructure capacity are other important factors.

Discoveries above the average size for the past decade must be made if production is to be sustained at a high level. Opportunities for making larger finds are greatest in little-explored areas.

DEVELOPMENTS IN EXPLORATION ACTIVITY FROM 1965 TO 2017

The first exploration well on the NCS was drilled in 1966 (see fact box 2.1). A total of 1 654 such wells had been spudded by 31 December 2017 (table 2.1).

Exploration has varied substantially over this 50-year period (figure 2.1). The first peak was reached in the mid-1980s, with up to 50 wells per year. From the end of the 1990s, activity declined to a low point of 12 wells in 2005. It then began to recover, and 65 wells were spudded in 2009. The post-2006 increase reflected changes to exploration policy combined with rising prices. Activity remained by and large high until 2015, but the steep slump in oil prices led to a substantial fall over the past two years. Nevertheless, the level is still high compared with 1998-2005.

Historically, the largest annual number of exploration wells has been drilled in the North Sea. In 2017, however, the level was highest in the Barents Sea for the first time (figure 2.2) with a record 17 wells drilled there. While a decline has been forecast in the Barents Sea for 2018, drilling in the North and Norwegian Seas is expected to rise.

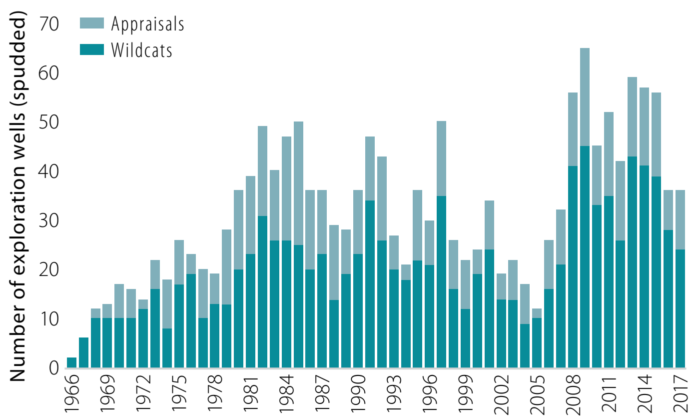


Figure 2.1 *Exploration wells spudded.*

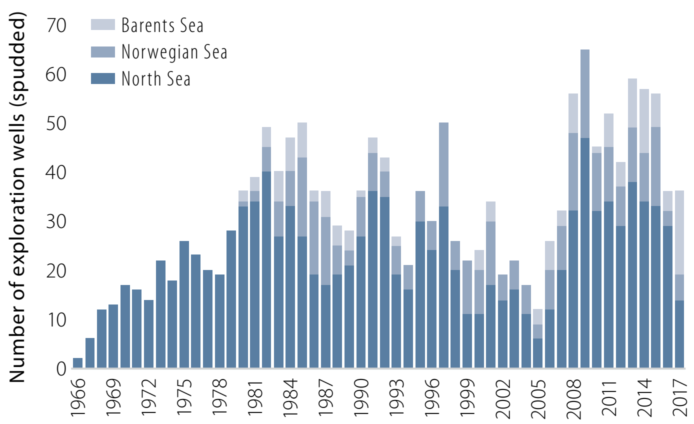


Figure 2.2 *Exploration wells spudded by area.*

Well type	Purpose		Area		
			North Sea	Norwegian Sea	Barents Sea
Exploration wells 1 654	Appraisal	1 092	733	242	117
	Wildcats	562	453	81	28
Total		1 654	1 186	323	145

Table 2.1 *Number of exploration wells spudded by category and area (at 31 December 2017).*

FACT BOX 2.1: *Exploration wells*

- **Exploration well.** Drilled to prove a possible petroleum deposit or to secure information for delineating a possible deposit. A collective term for wildcats and appraisal wells.
- **Wildcat.** Drilled to investigate whether a possible deposit contains petroleum.
- **Appraisal well.** Drilled to determine the size and extent of a petroleum deposit already proven by a wildcat.

DISCOVERIES ARE SMALLER

A high level of exploration in recent years has resulted in many discoveries (figure 2.3). On average, these are smaller than before.

International experience shows that the biggest finds are made early in the exploration phase of a new petroleum province, and that discovery size declines as the latter matures. This also applies to the NCS (figure 2.4). With the exception of Ormen Lange in 1997 and Johan Sverdrup in 2010, the largest finds were made in the first 20 years and discovery size has declined from the mid-1980s. The average discovery size (excluding resource class 6 (RC6) – see chapter 1 for a definition) over the past seven years has been about seven million standard cubic metres of oil equivalent (scm oe). Discovery size in figures 2.4 and 2.5 is based on the current estimate, not that reported when the discovery was made. The original estimate can differ from the current figure. Discovery size can increase or decrease over time in line with new knowledge about the reservoir.

The decline in average discovery size reflects the fact that the NCS has become more mature (figure 2.5). However, even very small finds can show good profitability if existing infrastructure is used effectively (see more in chapter 4). Maintaining a high level of exploration is important for identifying and developing small discoveries while the big installations are still on stream.

RESOURCE GROWTH AND PRODUCTION

The reduction in average discovery size has also meant a decline in resource growth over time. It has been substantially smaller from discoveries over the past 30 years than in the first two decades of Norwegian oil history. Figure 2.4, showing resource growth from discoveries by size, illustrates the trend. Resource growth in the various sea areas is presented in fact box 2.5.

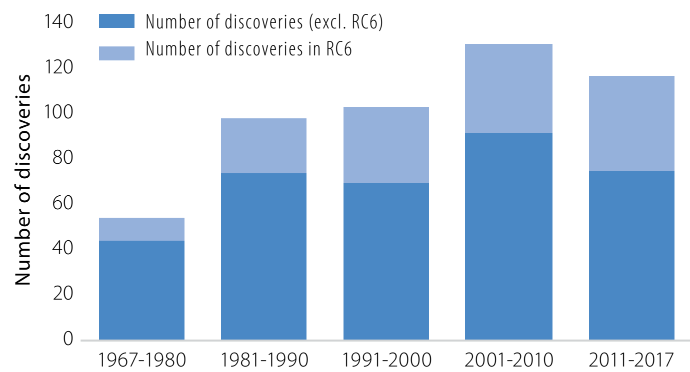


Figure 2.3 *Discoveries.*

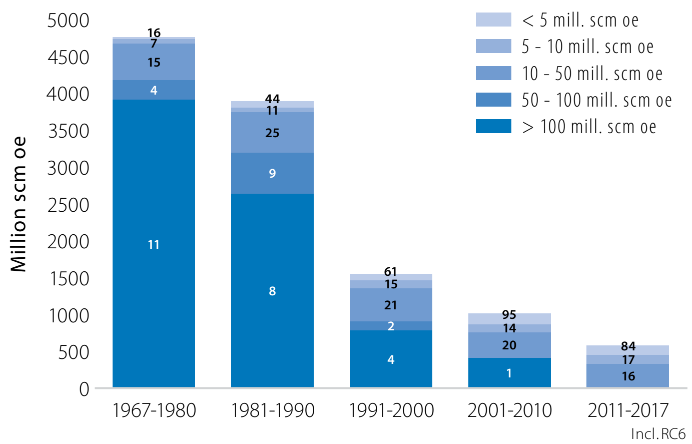


Figure 2.4 *Resource growth by discovery size. The number of discoveries is shown in the bars.*

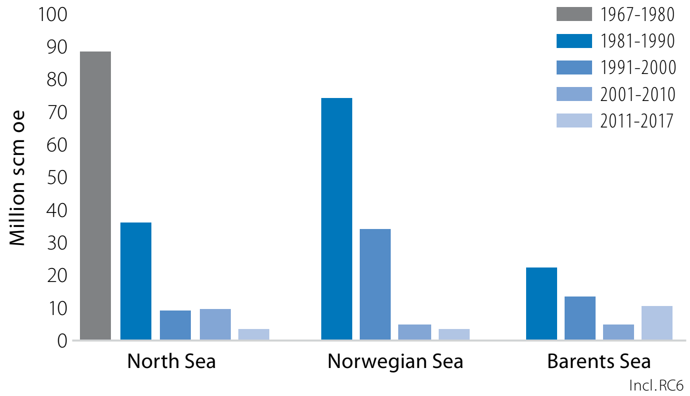


Figure 2.5 *Average discovery size by area.*

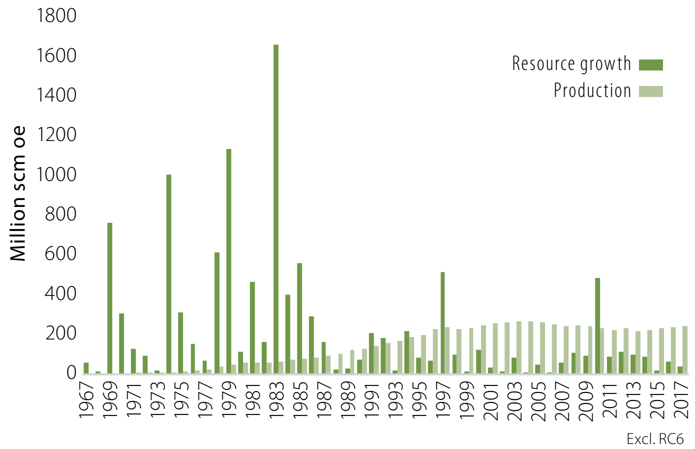


Figure 2.6 *Annual resource growth and production.*

During the first decade after Ekofisk was found in 1969, the big Statfjord, Sleipner Vest, Gullfaks and Oseberg fields were discovered and are still on stream. Most of the other largest fields followed in 1979-84 (figure 2.6). Almost 65 per cent of all proven resources were found in this period. The figure shows that, with the exception of Ormen Lange and Johan Sverdrup, resource growth from exploration has been low for the past 30 years. By and large, the annual figure has been smaller than production over the past two decades. Output has largely come from fields discovered in production licences awarded from 1965 to the early 1990s.

Figure 2.7 presents resource growth by decade of licence award. Almost half the total resource growth from exploration (by decade of licence award) has come from discoveries in licences awarded in the first to fifth licensing rounds (before 1980). Many of the exploration wells drilled over the past decade were located in pre-1980 acreage. That partly reflects the further development of new and known plays based on additional seismic surveys and continuous exploration drilling, combined with improved interpretation tools and methods (see chapter 6). Infrastructure expansion, further progress with new development concepts and innovative drilling technology have also made it financially interesting to explore ever-smaller prospects.

ACCESS TO ACREAGE

The government gives great emphasis to making acreage regularly available, which is important for maintaining interest in exploration and ensuring the development of commercial discoveries. Companies primarily gain access to acreage through licensing rounds, but can also buy or swop licence interests.

In line with the growth in the number of companies and licences, and with oil price trends, the secondary market (acquisition, swop and sale) for interests has expanded substantially since 2007. It peaked in 2013 (figure 2.8).

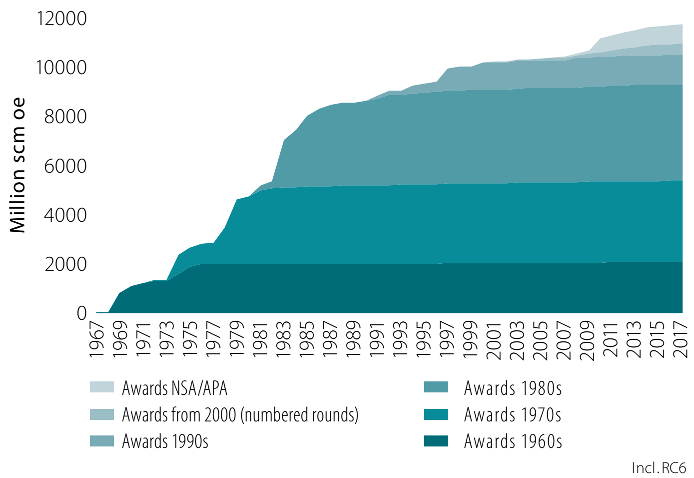


Figure 2.7 *Resource growth by decade of licence award.*

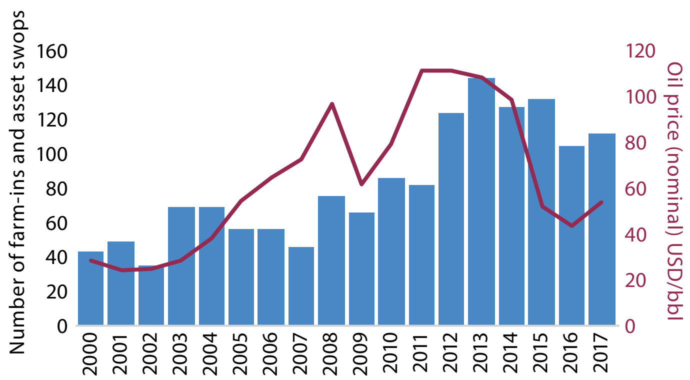


Figure 2.8 *Farm-ins and swops of licence interests.*

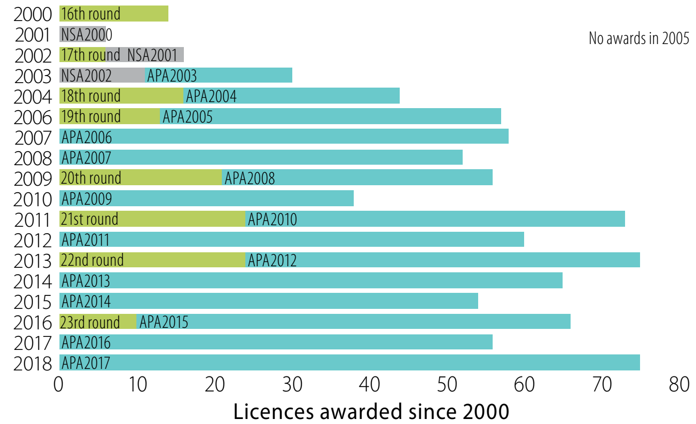


Figure 2.9 *Annual licence awards since 2000.*

LICENSING ROUNDS

Two types of licensing rounds with equal status are conducted on the NCS – numbered, and awards in predefined areas (APA).[5] APA rounds have taken place annually since 1999, while the numbered rounds in less-explored exploration areas are generally staged every other year. These regular rounds contribute to important predictability for the industry. The scope of awards is presented in figures 2.9 and 2.10.

The first licensing round in 1965 was clearly the most extensive in terms of acreage on offer. While the first four rounds were confined to the North Sea, parts of the Norwegian and Barents Sea were opened for exploration from the fifth round held in 1980-82.

Introduced in 2003, the APA scheme is intended to ensure efficient exploration of mature areas and to prove time-critical resources close to planned and existing infrastructure (fact box 2.3). It is important that acreage awarded gets explored quickly and efficiently so that existing infrastructure can be utilised in the best possible way and small discoveries are phased in swiftly if spare capacity is available. As new areas become mature, the APA coverage has been expanded on the basis of established criteria. See report no 28 (2010-2011) to the Storting on the petroleum sector as an industry for the future. One of the following criteria must be met: the area is close to infrastructure, has an exploration history, or borders on existing prede-

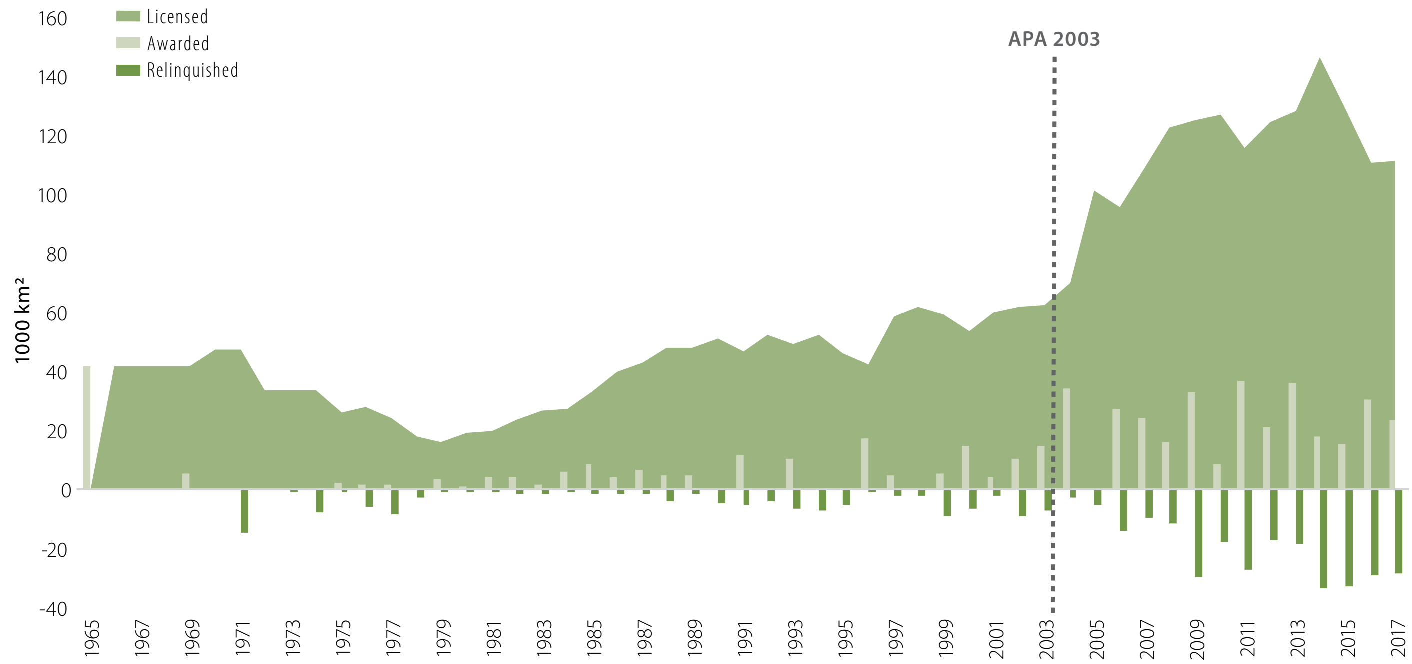


Figure 2.10 *Acreage awarded, licensed and relinquished.*

[5] They were called North Sea awards (NSA) from 1999 to 2002.

FACT BOX 2.2: *Work programme*

The government attaches obligations (a work programme) to production licences. Changes have occurred with these programmes as the NCS has matured. In the early rounds, when the NCS ranked as a frontier area and information was lacking, requirements often involved acquiring seismic data and drilling a specific number of firm wells. In the APA rounds covering mature areas, a licence is often required to acquire seismic data, through either purchases or surveys. A "drill or drop" obligation is also imposed. This means that the licensees have one-three years to decide whether to spud a wildcat. If they decided to drill, the licence is retained. If not, it lapses. Should a commercial discovery be made, the licensees must decide whether a plan for development and operation (PDO) is to be submitted. This process, with average figures from 2000, is illustrated in figure 2.11.

Licences which require a fixed number of wells to be drilled are still awarded in APA rounds, but on a smaller scale than before. This is because the largest and best-defined structures have already been drilled. Mapping remaining prospects is harder, and more extensive geoscientific analyses are often needed before a drilling decision can be taken.

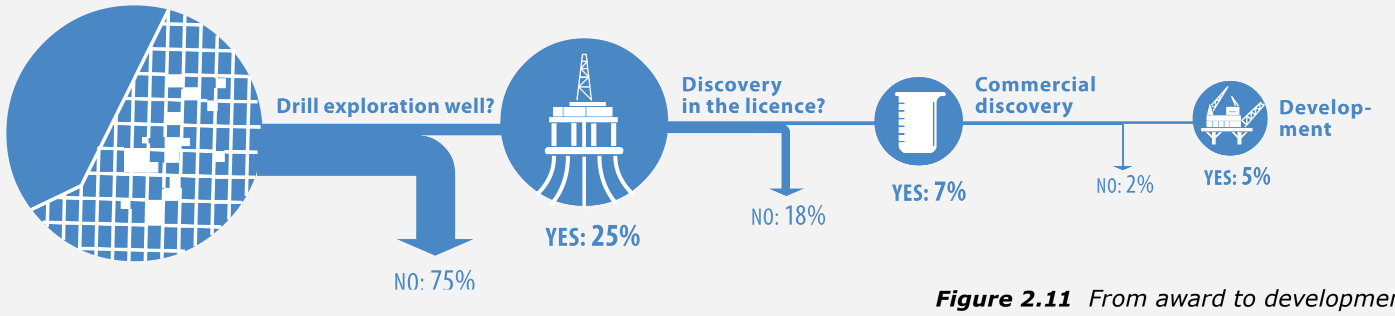


Figure 2.11 *From award to development.*

fined areas but has not been applied for in numbered rounds. Predictability about the areas which can be applied for, with a steady addition of new acreage, is important for the effectiveness of the scheme. Since the APA rounds were introduced, the number of licences and the amount of acreage awarded have increased considerably (figures 2.9 and 2.10).

More acreage has been relinquished over the past decade than before. Faster circulation of acreage was precisely one of the goals of the APA scheme. Stricter work programmes (fact box 2.2) and an increased area fee mean that licensees must work faster to evaluate prospectivity and relinquish holdings they find uninteresting. That means this acreage becomes available more quickly for other players with new eyes and ideas.

24TH LICENSING ROUND

Ahead of the announcement of a numbered licensing round, the companies are invited to nominate blocks they believe should be included. The NPD then prepares a recommendation to the Ministry of Petroleum and Energy (MPE) on the acreage which should be put on offer.

The 24th round was announced on 21 June 2017 with a deadline of 30 November 2017 for applications. It included 102 full or partial blocks – nine in the Norwegian Sea and 93 in the Barents Sea (figure 2.12).

APA 2017 AND 2018

Mature areas of the NCS remain attractive. A new record for the number of applications was set by the 2017 APA round, with 39 companies applying. This big interest partly reflected access to new and improved seismic data. Large parts of the NCS, particularly the mature areas of the North and Norwegian Seas, are now covered by broadband surveys. Combined with increased computing power and innovative interpretation and visualisation tools, that has made it possible to identify new exploration opportunities – including in previously explored acreage.

Figure 2.13 shows the extent of the expansion for the 2018 APA round. Since the 2017 round, the predefined areas have been expanded by 47 blocks in the Norwegian Sea and 56 in the Barents Sea. Applications can be submitted for all unallocated full or part blocks in these areas.

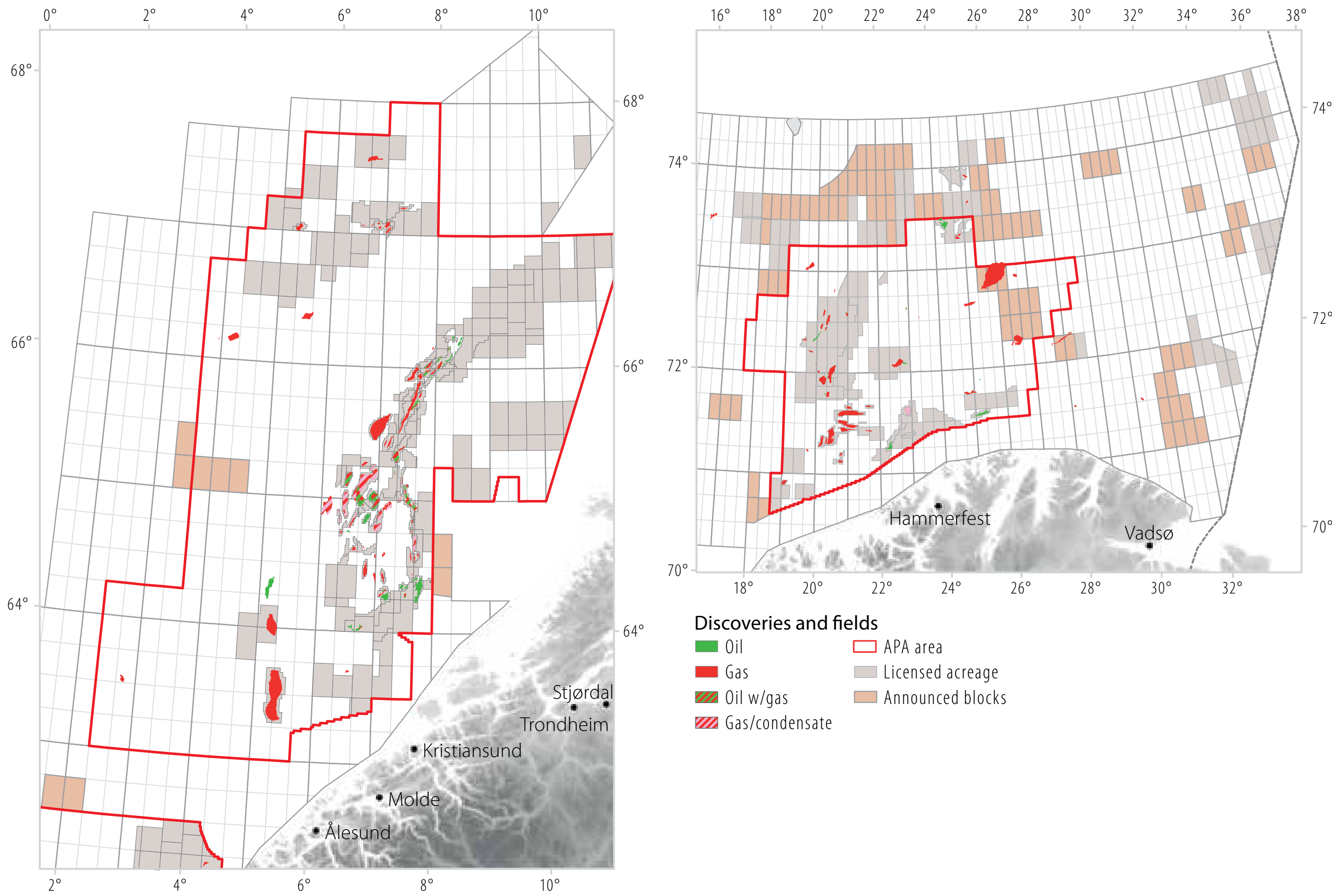


Figure 2.12 *Blocks put on offer in the 24th round.*

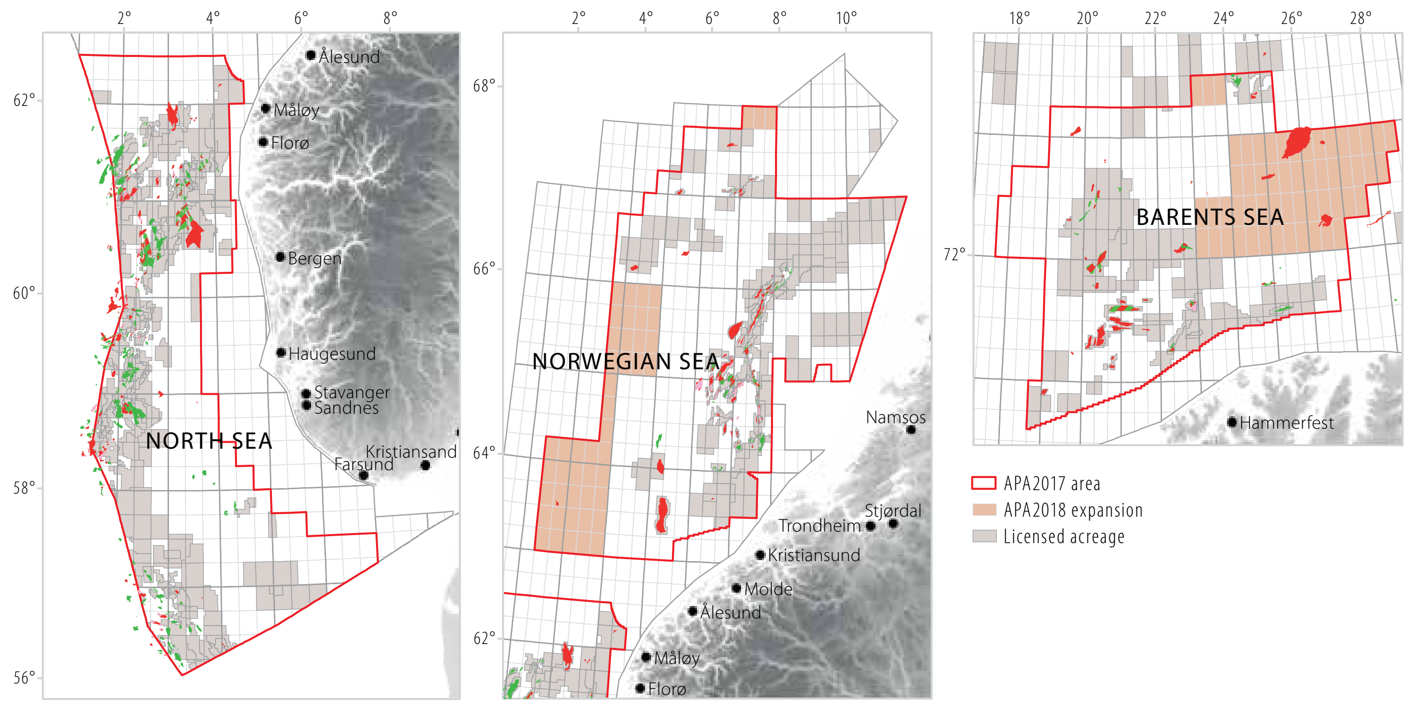


Figure 2.13 *APA 2018 expansion.*

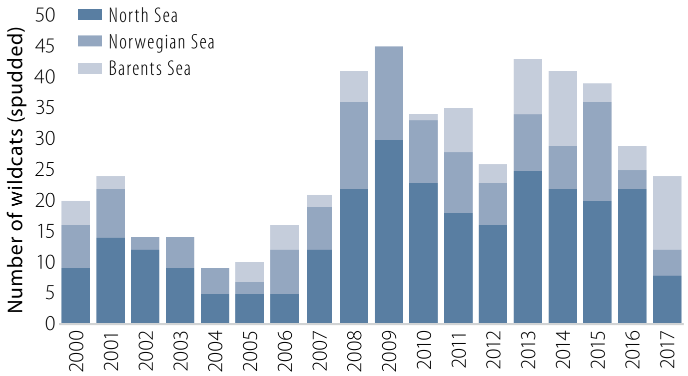


Figure 2.14 Wildcats by area.

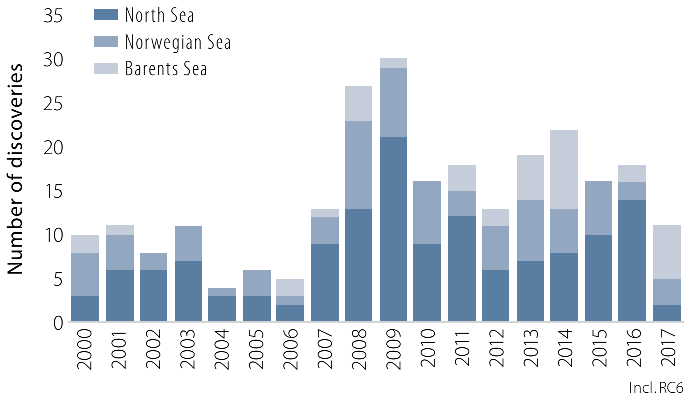


Figure 2.15 Discoveries by area.

EXPLORATION TRENDS ON THE NCS, 2000-17

WILDCATS

Developments in the number of wildcats by sea area in 2000-17 are illustrated in figure 2.14.

Relatively few wildcats were drilled in the North Sea during 2000-05, but the number increased substantially from 2007. Exploration remained high until 2016, with an average of 21 wildcats per year. Only eight wildcats were drilled in the North Sea during 2017.

Exploration in the Norwegian Sea has varied rather more than in the North Sea. Activity there was also high from 2008, but fell to three wildcats spudded in 2016.

In the Barents Sea, exploration has varied throughout the period. Since 2009, the number of wildcats has fluctuated between one and 12. Activity increased in 2017, and 17 wildcats were drilled.

DISCOVERIES

Developments in the number of discoveries after 2000 by area are presented in figure 2.15. The high level of exploration after 2006 resulted in a big increase in finds. Most were made in the North Sea with the exception of 2013, when the Norwegian Sea accounted for the majority, and 2014 and 2017, when the Barents Sea topped the list.

SUCCESS RATES

The average technical success rate (discoveries as a proportion of wildcats) has varied over time and between the different areas (figures 2.16 and 2.17). It has lain around 50 per cent in recent years (see chapter 6).

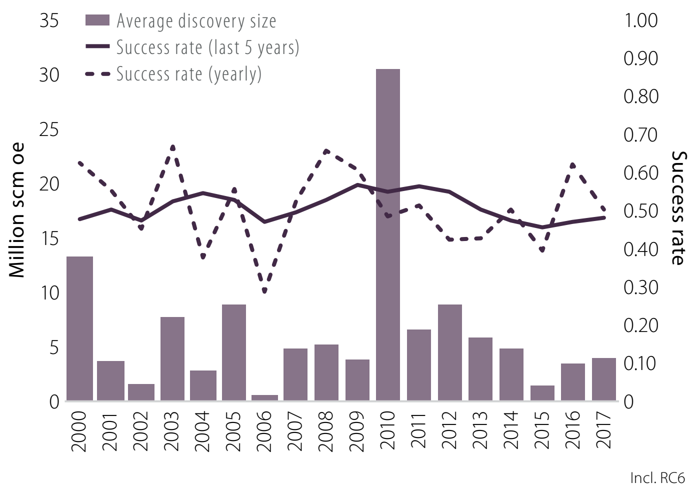


Figure 2.16 Technical success rate and average discovery size.

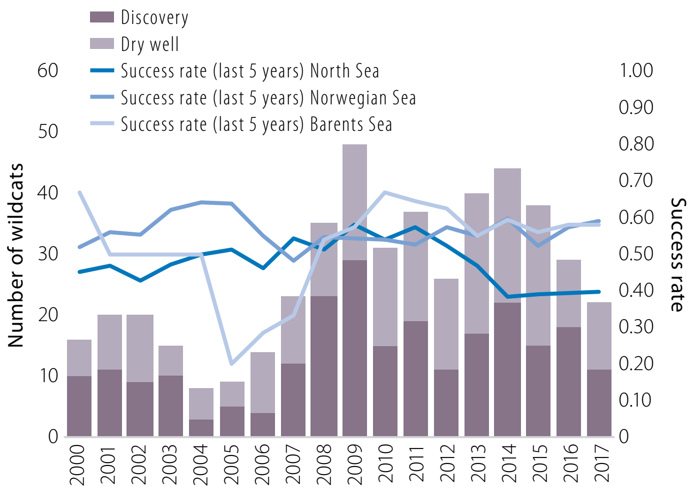


Figure 2.17 Technical success rate and wildcats by area.

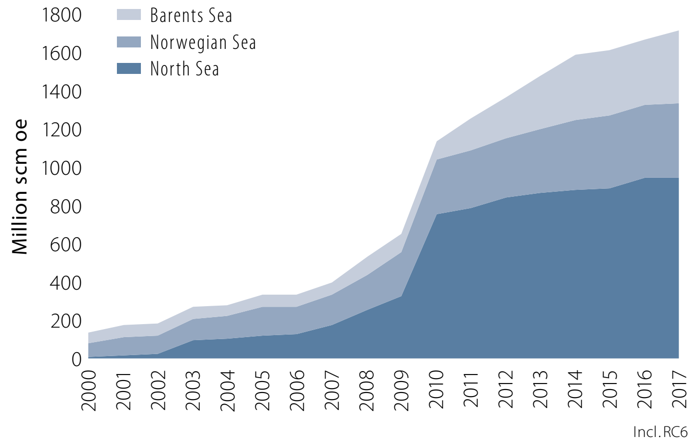


Figure 2.18 Accumulated resource growth by area.

ACCUMULATED RESOURCE GROWTH BY AREA

Overall resource growth in the Norwegian and Barents Seas during the past 18 years has been somewhat lower than in the North Sea (figure 2.18). A total of 257 discoveries were made in 2000-17, of which 36 were larger than 10 million scm oe. One really large find (Johan Sverdrup) was made in this period, and accounted for 24 per cent of total resource growth.[6] The biggest contributions to resource growth in the Barents Sea have come from 7324/8-1 (Wisting), 7220/7-1 (Havis) and 7220/8-1 (Skrugard). Contributors in the Norwegian Sea include 6507/5-3 (Ærfugl) and 6406/3-8 Maria. Of the 257, 175 are below five million scm oe. Such smaller discoveries account for 14 per cent of resource growth. Fact box 2.5 presents resource growth in the various areas of the NCS.

FACT BOX 2.3: *Changes to the regulatory framework and licensing policy*

Licensing policy in mature areas was revised in 1999 by establishing the annual NSA rounds, which were further developed in 2003 into the APA. The aim was to prove and recover commercial resources in mature areas before the infrastructure closed down. Another important objective was to contribute to efficient exploration at the companies by providing greater predictability for the industry through a regular supply of new acreage.

The government also made provision in 2000 for admitting new companies, and the offer to prequalify as operators and licensees was established. This scheme aimed to help improve predictability for new companies seeking to become established on the NCS, either through awards or by farming into licences.

A reimbursement system for exploration costs introduced with effect from 1 January 2005 put companies without taxable earnings on an equal footing with those which have such revenues in terms of the tax treatment of exploration expenses. The scheme gives companies with a tax-deductible loss the right to have the tax value (78 per cent) of their exploration costs reimbursed rather than carrying them forward with a supplement for interest. These alternatives have the same financial outcome for the government. The goal of the reimbursement scheme was to reduce entry barriers by putting new companies in the exploration phase on an equal footing with established players who had taxable earnings

FACT BOX 2.4: *Relicensing acreage*

Much of the acreage being explored today has been awarded and relinquished several times (figure 2.19). Improved seismic data, information from more wells, innovative technology, and new thinking and ideas mean that petroleum resources are being proven in areas which have been explored many times before. A number of areas covered by the APA scheme and around the big North and Norwegian Sea fields have been awarded four or five times. Although acreage is awarded several times, substantial discoveries can still be made. 16/2-6 Johan Sverdrup, the Johan Castberg discoveries 7220/8-1 (Skrugard) and 7220/7-1 (Havis), and 7220/11-1 (Alta) are good examples.

[6] The resource estimate for Johan Sverdrup is about 400 million scm oe, including phase two of the development project. Source: Equinor

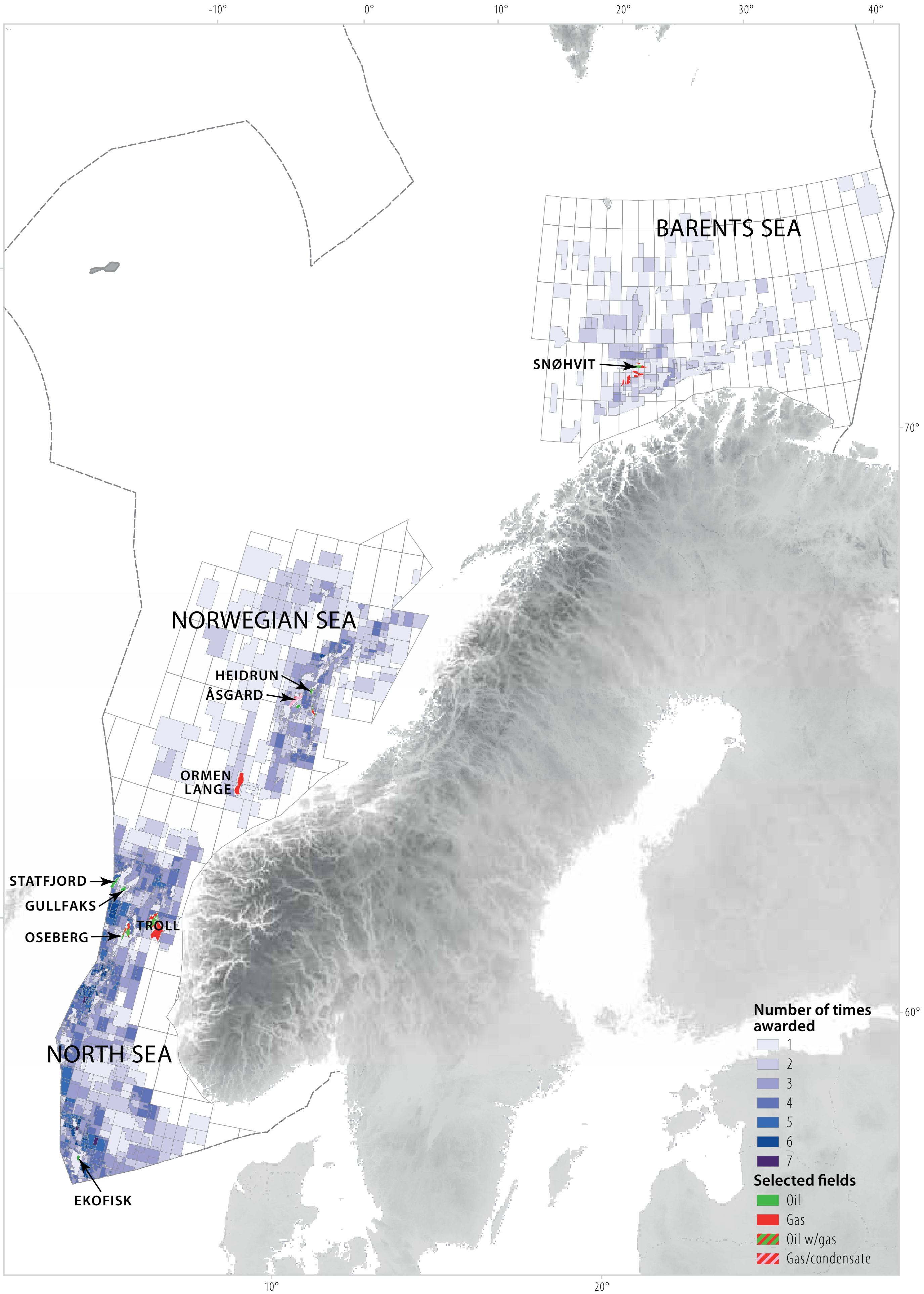


Figure 2.19 *Number of times acreage has been awarded.*

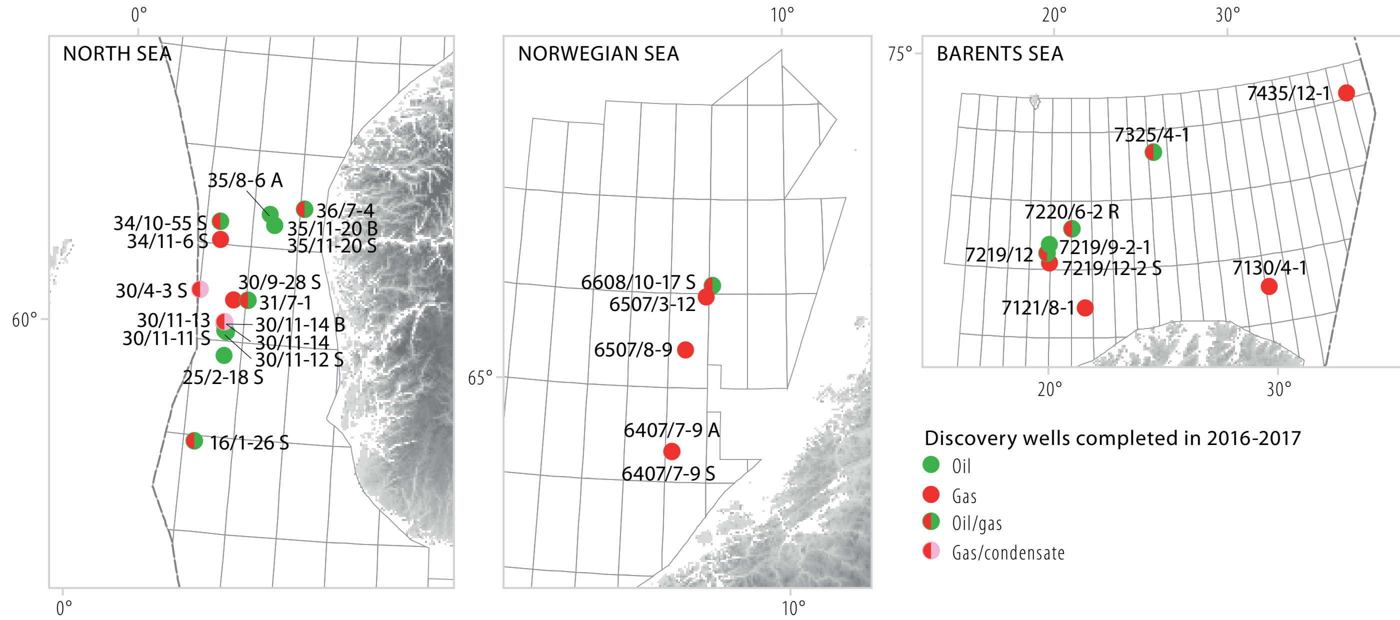


Figure 2.20 *Discoveries on the NCS in 2016-17.*

EXPLORATION RESULTS 2016-17

Seventy-one exploration wells were completed on the NCS in 2016-17, of which 52 were wildcats. A total of 29 discoveries were made, giving a success rate of 62 per cent in 2016 and 50 per cent in 2017. The biggest finds in this period were 36/7-4 (Cara) and 31/7-1 (Brasse) in the North Sea, and 7219/12-1 (Filicudi) and 7435/12-1 (Korpfjell) in the Barents Sea. Figure 2.20 shows all the finds made in the period, while fact box 2.5 presents resource growth in the various sea areas.

Thirty exploration wells were completed in the North Sea during 2016 and 12 in 2017. Twelve were appraisals. Sixteen of the wildcats encountered hydrocarbons.

While exploration activity in the Norwegian Sea was low during 2016, with only three wildcats, there was a slight increase in 2017 to five wells (four of them wildcats). Five discoveries were made in 2016-17.

Four exploration wells were drilled in the Barents Sea during 2016 – three wildcats and one appraisal. Activity increased in 2017, when a new exploration record was set with 17 completed wells. Five were appraisals. A total of seven discoveries were made in 2016-17.

Expectations were high for Statoil's 7435/12-1 (Korpfjell) wildcat, the very first to be spudded in Barents Sea South-East after the area was opened for exploration in 2013. It was drilled on the Haapet Dome, a large structure close to the boundary with the Russian sector. Many had hoped for a big oil discovery, but instead the well encountered small quantities of gas. Although the result was disappointing, it lay within the NPD's expected uncertainty range. Preliminary estimates put the size of the discovery at eight to 11.5 million scm oe. Although the find is not commercial at present, the well has contributed important new geological knowledge about the area.

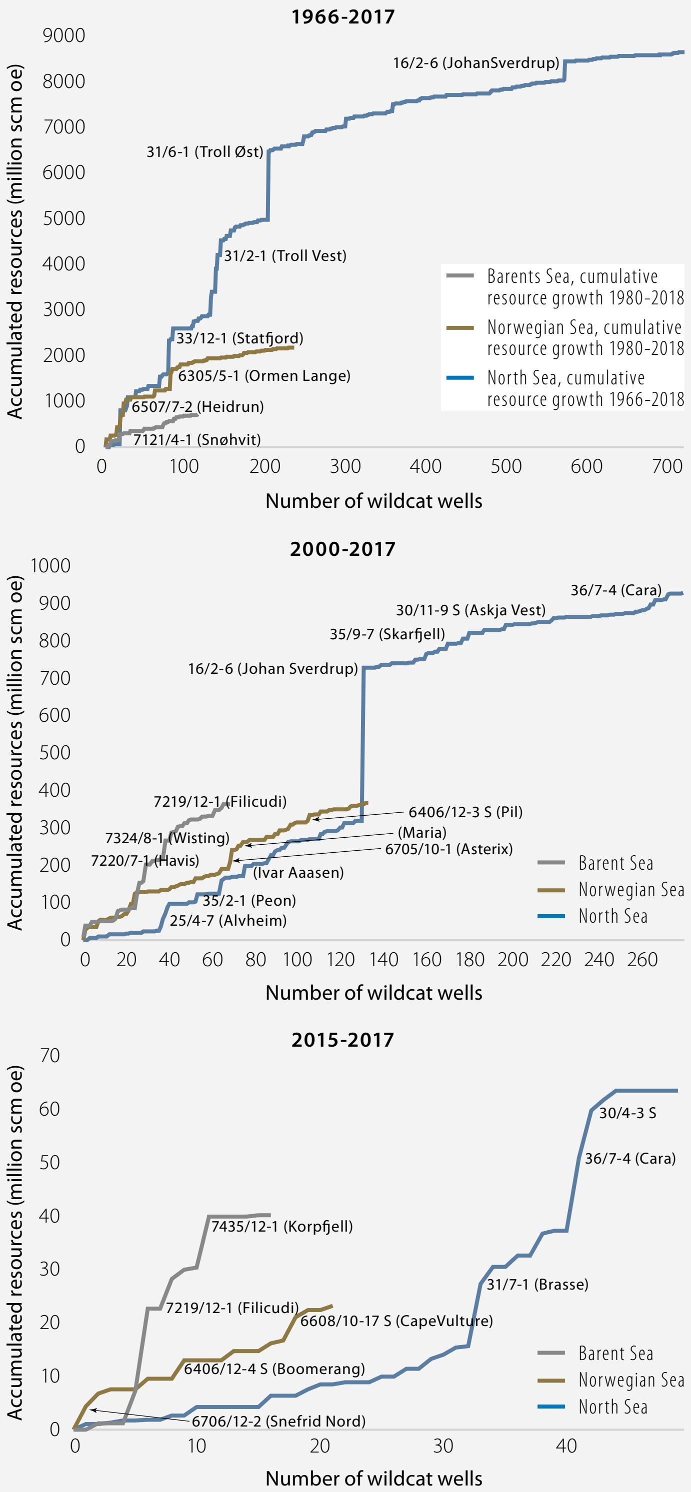


Figure 2.21 *Accumulated resource growth in the North, Norwegian and Barents Seas for 1966-2017, 2000-17 and 2015-17.*

Fact box 2.5: *Exploration curves*

The exploration curve for 1965-2017 shows that the largest number of wells drilled and the biggest resources found were in the North Sea. The Norwegian and Barents Sea were opened for exploration in 1980. More wells were drilled and resources found in the Norwegian Sea than in the Barents Sea.

In 2000-17, the largest number of wells drilled and the biggest resources were again found in the North Sea. Resource growth was about the same in the Norwegian and Barents Seas, but with almost twice as many wells drilled in the former area as in the latter.

The largest number of wells and the highest resource growth in 2015-17 were in the North Sea. Resource growth in the Barents Sea was roughly 60 per cent of the level in the North Sea, but fewer wildcats were drilled there. The Norwegian Sea accounted for the smallest resource growth, even though a few more wells were drilled there than in the Barents Sea.

The horizontal axes show the number of wildcats in the order they were drilled. When a new discovery is made, the resources involved are represented as accumulated values along the vertical axis. A steep curve shows that a lot of resources were found with relatively few wells, while a shallow curve indicates that proven discoveries were small.

CHAPTER 3
UNDISCOVERED RESOURCES

Updating the estimate for undiscovered resources shows that the amount remaining provides the basis for exploration and oil and gas production over several decades to come.

The NPD's updated estimate for undiscovered resources is 4 000 million standard cubic metres of oil equivalent (scm oe), up by almost 40 per cent from the previous figure. This big growth reflects the NPD's mapping of resources in the northern part of Barents Sea East. The new estimate shows that remaining resources can provide the basis for oil and gas production over many decades.

The NPD regularly updates its estimate for undiscovered resources on the Norwegian continental shelf (NCS) (see the section on resource classification and resource accounts at 31 December 2017 in chapter 1). Its previous assessment was made in 2015 (see the NPD's resource report for 2016). The calculation method has remained unchanged since the mid-1990s, which provides a good basis for comparing estimates over time.

UPDATED ESTIMATES FOR UNDISCOVERED RESOURCES

Total undiscovered resources are estimated to lie between 2 330 (P95) and 6 200 (P05) million scm oe (fact box 3.1 and figure 3.1). The expected value is 4 000 million scm oe, up by 37 per cent from 2 920 million in 2015. This big increase primarily reflects the new estimate for Barents Sea North in 2017.

DISTRIBUTION BY AREA

Estimates for undiscovered resources in the North and Norwegian Seas and in Barents Sea South at 31 December 2017 (figure 3.2) are virtually the same as in 2015.

Uncertainty in these estimates is greatest in areas with little information and a short exploration history, such as much of the Barents Sea. That applies particularly to Barents Sea South-East and North. Uncertainty is considerably smaller in the North Sea and the well-explored part of the Norwegian Sea.

The estimate for undiscovered resources shows that the amount remaining could provide the basis for exploration and oil and gas production over several decades to come.

More than 60 per cent of undiscovered resources are expected to lie in the Barents Sea, with the remainder divided more or less equally between the North and Norwegian Seas (figure 3.3).

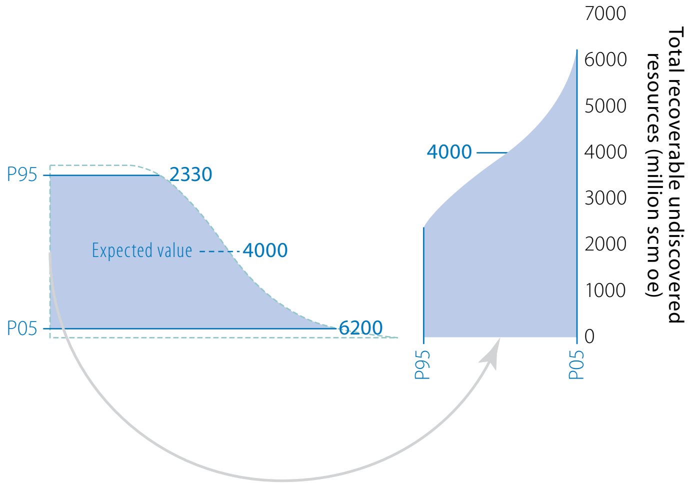


Figure 3.1 *Estimated undiscovered resources – expected value and uncertainty range.*

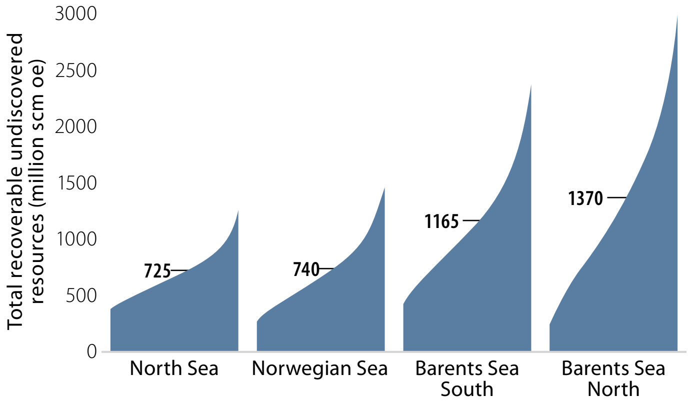


Figure 3.2 *Undiscovered resources by area within the spread from P95 to P05. The numbers shown are the expected values.*

Fact box 3.1: *Expected value*

The estimate for undiscovered resources is uncertain. Great uncertainty prevails about the mapped prospects, and even more over the number and size of those which have yet to be identified. The method used by the NPD to estimate undiscovered resources (fact box 3.2) quantifies the uncertainty. Estimates are expressed as probability distributions, not single figures. When this report cites the estimate as a single figure, the expected value of the probability distribution is used. The example shows that the probability of finding more than 2 330 million scm oe is 95 per cent, and of finding more than 6 200 million scm oe is five per cent (figure 3.1).

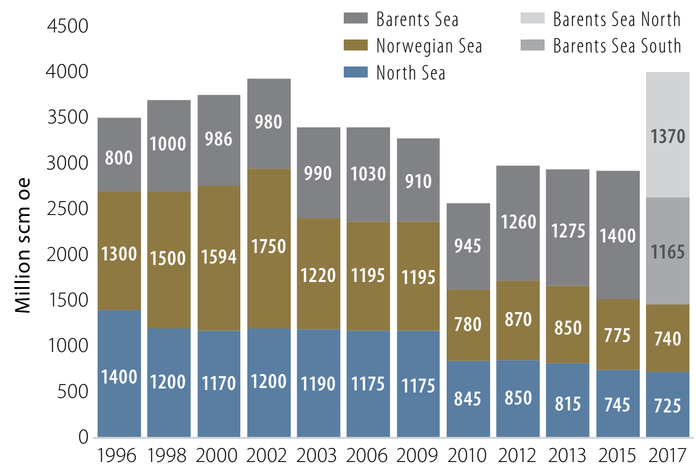


Figure 3.5 *Development in estimates for undiscovered resources over time. The 2017 estimate includes the eastern part of the Norwegian sector in Barents Sea North.*

Liquids are expected to account for just over half the undiscovered resources. As figures 3.3 and 3.4 show, the distribution between liquid and gas varies from one sea area to another.

HISTORICAL CHANGES

The estimate for total undiscovered resources has varied over time (figure 3.5). New knowledge from mapping and exploration wells may lead to substantial revisions of the figures, both positive and negative. Over time, however, estimates will reduce naturally as prospects are drilled.

After rising from 1996 to 2002, the estimates declined up to 2017. The discovery of Ormen Lange in 1997 raised great expectations for a number of large structures in the deepwater areas of the Norwegian Sea. However, disappointing wildcats prompted a downgrading of the estimates in 2003. That related particularly to the gas potential in the deepwater areas.

While the estimate for the Barents Sea increased in 2010, those for the North and Norwegian Seas were reduced. These reductions primarily reflected lower expectations for gas. The main reason in the Norwegian Sea was further disappointing exploration results with large structures in the deepwater areas. Changed expectations of the potential off Lofoten, Vesterålen and Senja, based on seismic data acquisition and mapping by the NPD, also affected the results. See the NPD's 2010 reports on *Petroleum resources in the sea areas off Lofoten, Vesterålen and Senja and Geofaglig vurdering av petroleumsressursene i havområdene utenfor Lofoten, Vesterålen og Senja* (in Norwegian only).

The background for the 2012 increase in the Barents Sea was the NPD's mapping and inclusion of Barents Sea South-East. This area was incorporated in the Norwegian sector after the boundary treaty with Russia came into force in 2011. In the same year, the sea areas around Jan Mayen were included in the estimate for the Norwegian Sea. That increased the total estimate for undiscovered resources.

Before 2017, the resource estimate for the Barents Sea primarily covered undiscovered resources in Barents Sea South – including those in plays which extend into Barents Sea North. The NPD's mapping of the latter area in 2016-17 led to the eastern part being separated out with its own estimate. See the NPD report on *Geological assessment of petroleum resources in eastern parts of Barents Sea North 2017.* This area accounts for about 35 per cent of the undiscovered re-

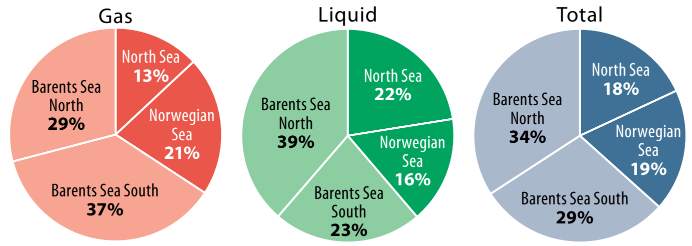


Figure 3.3 *Distribution of undiscovered resources in each area: gas, liquids and total.*

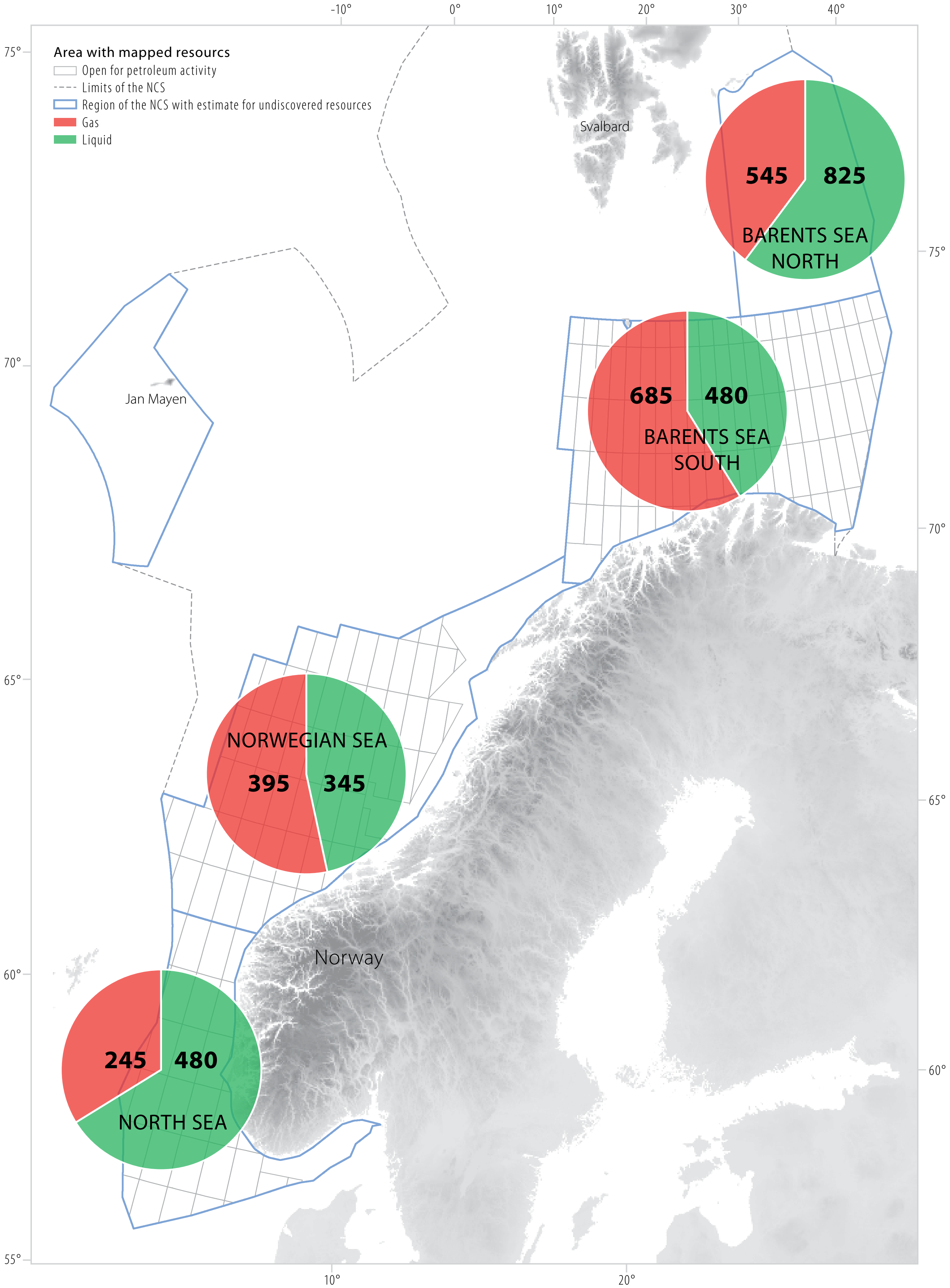


Figure 3.4 *Expected relationship between undiscovered liquid and gas in the various areas. Figures in million scm oe.*

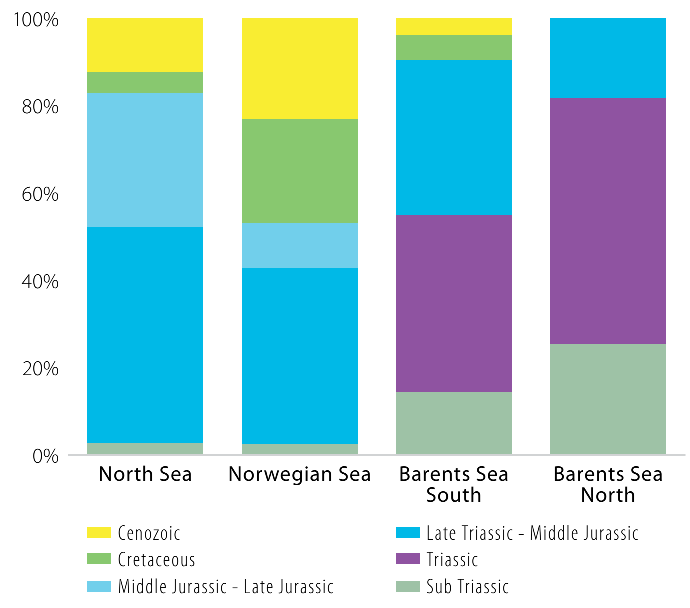


Figure 3.6 *Recoverable undiscovered resources in each area by stratigraphic level. The percentage distribution reflects the geological development in each area.*

sources, and thereby contains the largest proportion of these on the NCS. No similar mapping has been carried out in the other parts of Barents Sea North.

ESTIMATES BY STRATIGRAPHIC LEVEL

How contributions to resources break down by geological time period varies between the areas. That reflects their geological development.

Figure 3.6 shows that about 80 per cent of the undiscovered resources in the North Sea are expected to lie in Jurassic plays, while the corresponding figures for the Norwegian Sea, Barents Sea South and Barents Sea North are about 50 per cent,[7] 35 per cent and 18 per cent respectively. The Norwegian Sea contains a larger proportion of younger rocks, while these (Late Jurassic, Cretaceous and Palaeocene) have been eroded away in parts of the Barents Sea. That means older rocks, primarily Triassic, lie at depths favourable for petroleum generation.

Fifty-five per cent of undiscovered resources in Barents Sea South are expected to lie in Triassic or older plays, while the corresponding estimate for Barents Sea North is about 80 per cent.

Fact box 3.2: *Undiscovered resources are estimated for each play*

The estimate for undiscovered resources is based on the NPD's analyses of available data from the NCS. These assessments cover company and NPD interpretations of seismic data, mapping, studies and evaluations of prospectivity in areas both open and closed for petroleum operations. Data from wells, discoveries, fields and mapped prospects occupy a key place in this work. The NPD uses this information to define plays and then to develop a resource estimate for each of these.

A **play** is a geographically delineated area where several geological factors interact so that producible petroleum can be proven. These are as follows. 1) A permeable/porous reservoir rock, where petroleum can accumulate. Reservoir rocks in a specific play will be at specified lithostratigraphic levels. 2) A trap, which is a tight rock or geological structure encasing the reservoir rock so that petroleum is retained and accumulated. The trap must have formed before petroleum has ceased to migrate. 3) A source rock, such as shale, limestone or coal, containing organic material which can be converted to petroleum. This rock must also be mature – in other words, temperature and pressure must be such that petroleum actually forms. A migration route has to exist so that petroleum can move from source to reservoir rock. A play is confirmed when it yields producible petroleum. Production does not have to be commercial. If producible petroleum has yet to be proven, a play is unconfirmed.

A **prospect** is a possible petroleum trap with a mappable, delineated rock volume.

For a more extensive description of the methodology, see the resource report for 2016.

[7] The upper part of the Triassic is included in Early to Middle Jurassic plays in the North and Norwegian Seas, but makes a limited contribution to resources in these plays.

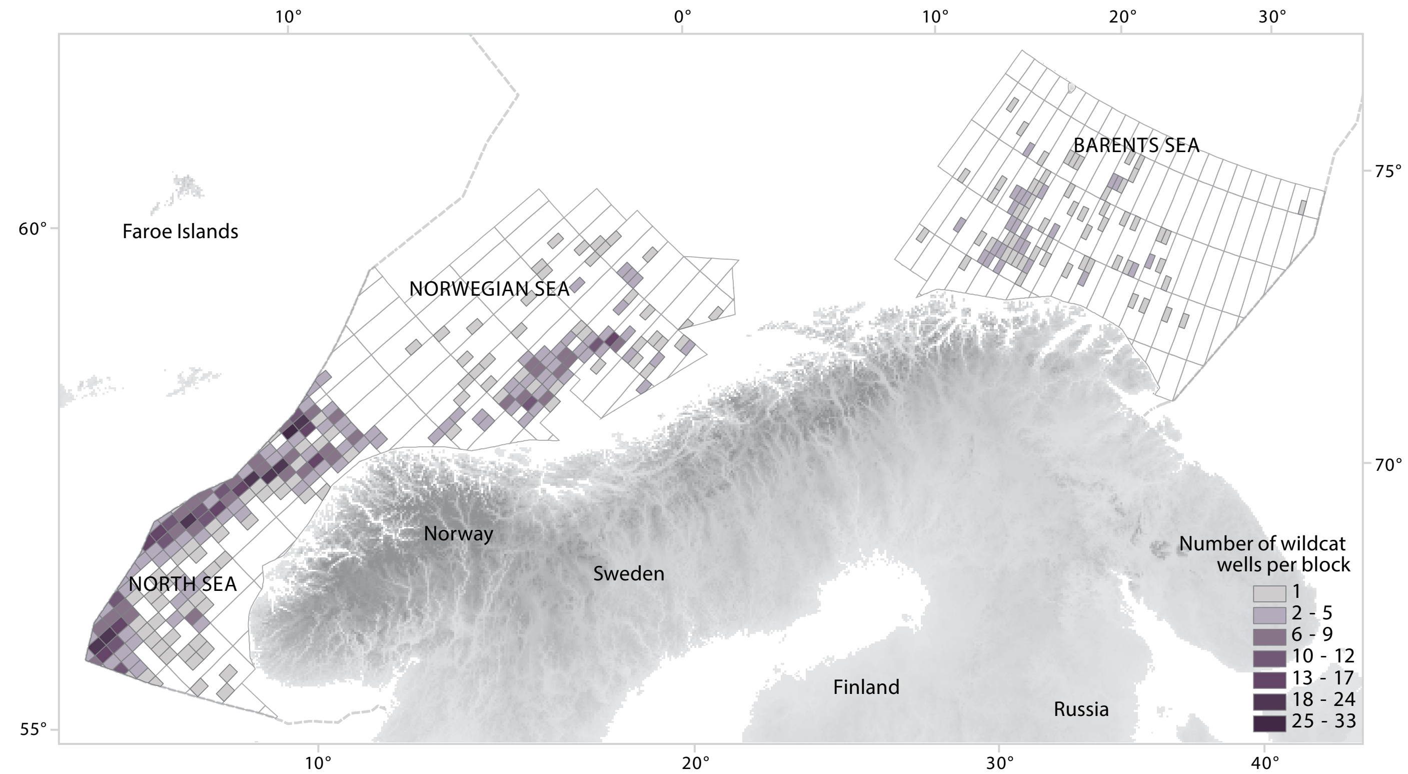


Figure 3.7 *Wildcats per block.*

WELL AND RESOURCE DENSITY

With some exceptions, the North and Norwegian Seas and Barents Sea South have been opened for petroleum operations. These areas total about 579 000 km^2. By comparison, mainland Norway covers some 324 000 km^2.

Wildcats completed at 31 December 2017 totalled 731 in the North Sea, 241 in the Norwegian Sea and 116 in Barents Sea South. Figure 3.7 shows the number of wildcats per block as an illustration of the degree of exploration.

Total resource density (proven and undiscovered) in Norway's North Sea sector is very high, at 66 million scm oe per 1 000 km^2. This is very high, also in a global context, and comparable with the best petroleum provinces in the Middle East.

The Norwegian and Barents Seas cannot be compared with the North Sea, which represents a unique petroleum province (figure 3.8). Total resource density in the Norwegian Sea and Barents Sea South averages 10 million and 5.5 million scm oe per 1 000 km^2 respectively. The estimate for undiscovered resources in the mapped part of Barents Sea North gives a relatively high average resource density of about 10 million scm oe per 1 000 km^2.

The North Sea ranks as a unique petroleum province because of its combination of a very extensive and productive source rock and good reservoir formations of varying geological age. The most important source of oil and gas is organically rich Late Jurassic shales. These rocks extend across much of the North Sea at a favourable depth for generating hydrocarbons. Moreover, the traps formed at a favourable time in relation to hydrocarbon migration. Similar conditions are found on the Halten and Dønna Terraces in the Norwegian Sea. However, traditional plays with Jurassic source and reservoir rocks do not function in the deepwater areas to the west. These sediments lie too deep. On the other hand, a potential exists in younger Cretaceous and Palaeocene rocks.

Geological developments in the Barents Sea have differed greatly from those in the North Sea, and were strongly influenced by several phases of burial, uplift and subsequent erosion. As a result, Jurassic rocks only lie at a favourable depth for generating hydrocarbons in certain areas. Uplift and erosion have also meant that petroleum is not always retained in the traps, primarily because of leakage. In areas where Jurassic rocks are absent or too shallow, Triassic or older sources could generate hydrocarbons. These source rocks do not appear to be as rich as their Jurassic equivalents in the North Sea.

The Barents Sea is a very large area, and extensive parts of it are relatively little explored. Its geological history is more complicated than in the other sea areas. Every well, whether dry or proving a discovery, provides new information about the geology and petroleum systems. Most of the prospects to be drilled in 2018 are geologically independent of those explored in 2017, and will extend knowledge of the various parts of the Barents Sea.

Fact box 3.3: *Seismic surveying on the Gardarbank High*

The NPD's acquisition of geological information and mapping of unopened and little-explored parts of the NCS helps to enhance understanding of the geology and increase data coverage of these areas. A good data and knowledge base is a prerequisite for the government to play a decisive role in resource management. The NPD's mapping work is funded over the central government budget.

In the autumn of 2017, the NPD acquired some 4 500 kilometres of two-dimensional seismic data on the Gardarbank High east and north-east of Bjørnøya in the Barents Sea. This geological ridge lies between the Spitsbergen Bank and the Hopen Deep.

Seismic surveys were conducted by the NPD in the eastern part of Barents Sea North in 2012-16. Results from this work were presented in the spring of 2017 in the report *Geological assessment of petroleum resources in eastern parts of Barents Sea North 2017.*

The survey on the Gardarbank High represented an extension of this work towards the west, and provided substantially better data coverage of the area. Plans call for work on processing the new seismic information to be completed in the third quarter of 2018, and the data will then be included in the NPD's evaluation projects.

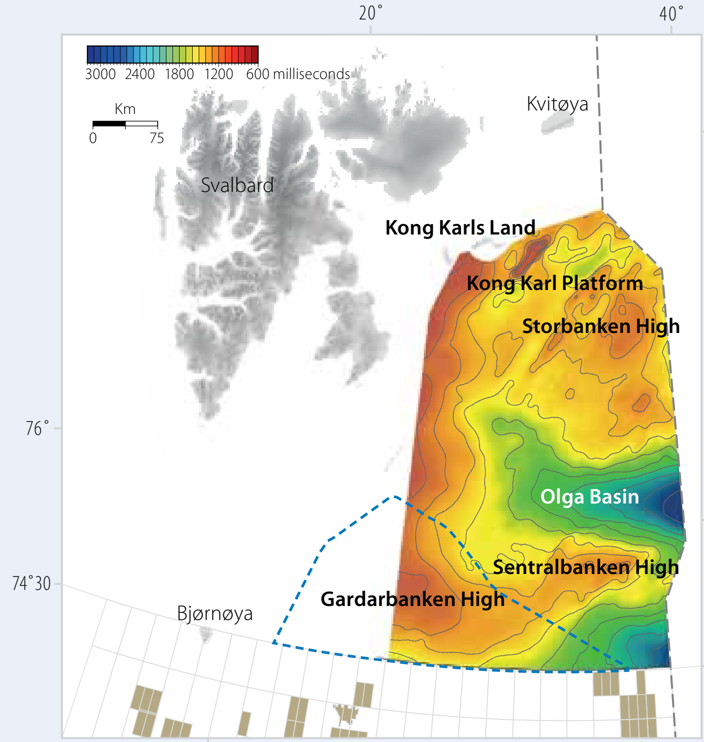


Figure 3.9 *Time contour map for the top of the Permian which shows the extent of the mapped area. Source:* Geological assessment of petroleum resources in eastern parts of Barents Sea North 2017. *The dotted line shows the survey area around the Gardarbank. High in the autumn of 2017.*

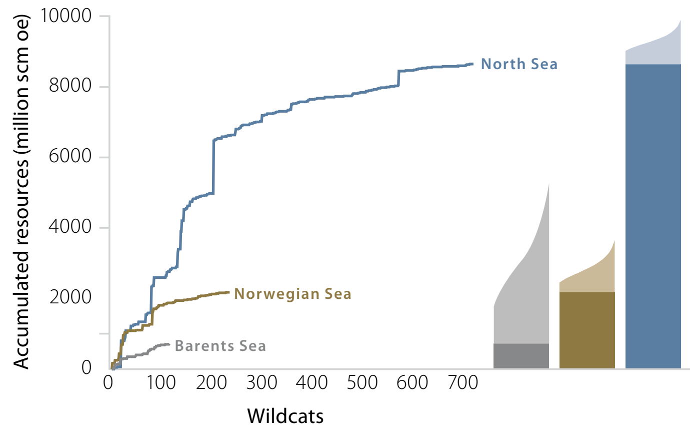


Figure 3.8 *Accumulated resources by area. Resources already discovered are shown in dark colours. Undiscovered resources are shown with their uncertainty range in lighter colours on top.*[8]

[8] The figure does not show the uncertainty in proven resources.

Fact box 3.4: *Shallow drilling in Barents Sea North*

Shallow drilling is used to acquire data on the sedimentary strata. Measuring five-seven centimetres in diameter, the cores acquired provide information on rocks types and sedimentary structures. They can also provide the basis for indicating the potential of the formations to act as source, reservoir or cap rock. These cores provide a good foundation for regional correlations and increased understanding of geological developments. The drilling depth of this type of well is limited to 200 metres beneath the seabed.

Geological investigation of Barents Sea North began with the acquisition of 2D seismic data in the mid-1970s. A need eventually arose to acquire geological samples to understand which rocks (reflectors) were giving the signals which appeared on the seismic maps. Knowledge about the age of the rocks was also important for understanding geological developments in Barents Sea North over time. A number of scientific shallow wells were drilled in the late 1980s to learn more about the geology of the area.

Funds were appropriated over the government budget in 2015 for shallow drilling, and geological material was obtained from cores up to 200 metres long. The primary area for this acquisition was south and north of Kvitøya. The NPD drilled seven wells at locations chosen on the basis of 2D seismic data (figure 3.10). The aim was to take cores from lithostratigraphic boundaries which occur mainly at deep levels in the Barents Sea but which, for various geological reasons, are shallower in the area investigated. A total of 1 048 metres of geological material were recovered, and these cores have increased understanding of the geology in northern parts of the Barents Sea.

Results from the six shallow wells south of Kvitøya showed that the oldest rocks are Carboniferous and Permian carbonates and shales. The boundary between Permian and Triassic is well preserved in the cores. Cores were taken from a dark Middle Triassic

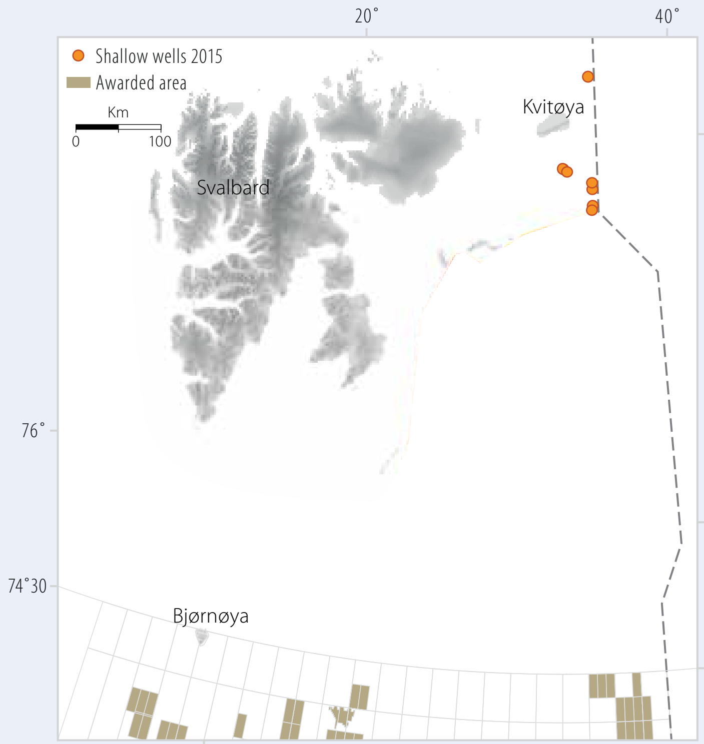


Figure 3.10 *Shallow drilling off Kvitøya in 2015.*

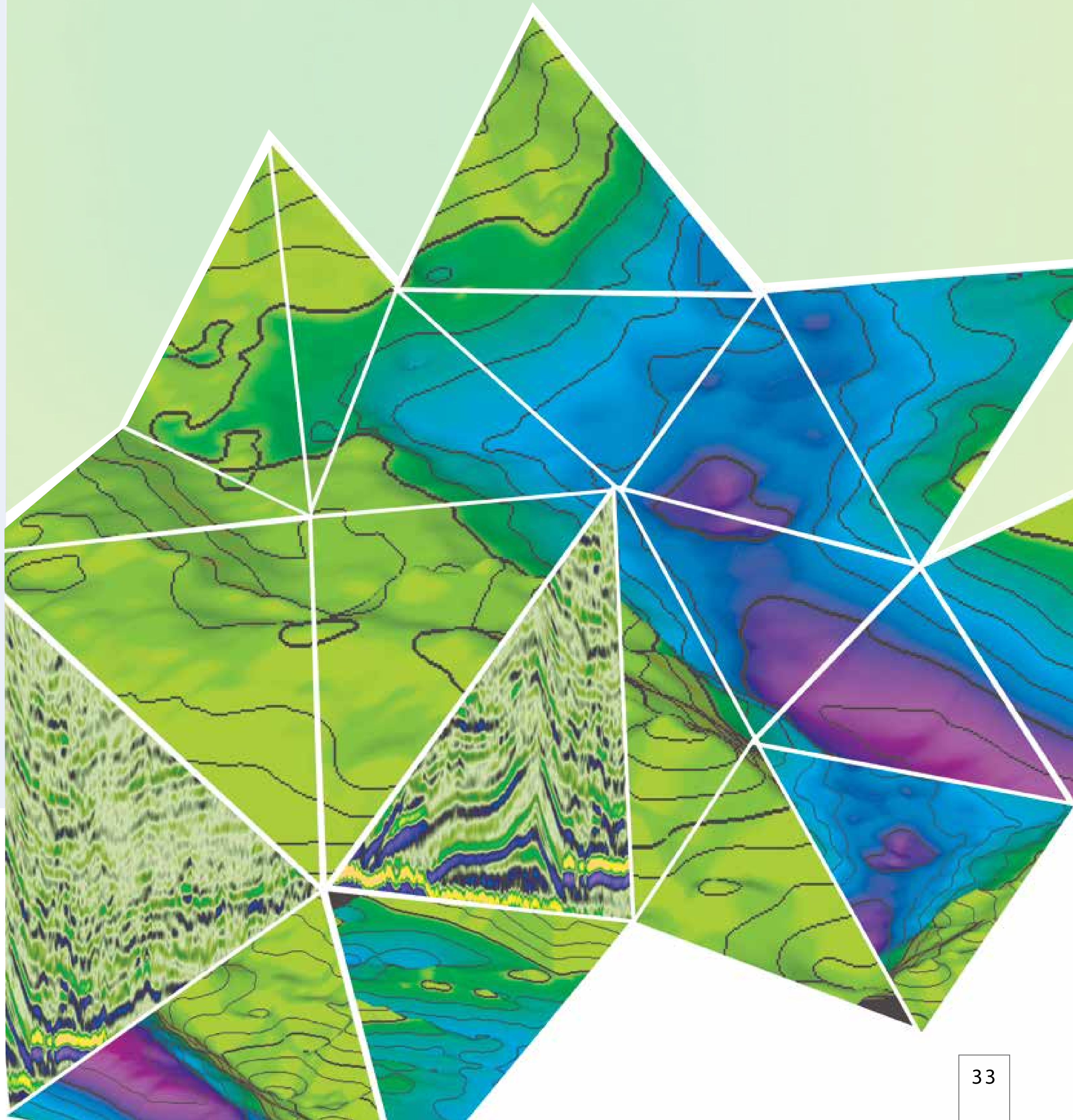
shale. A well north of Kvitøya found dolomites, which are likely to have been deposited in the Carboniferous.

Cores from the seven wells have been subjected to detailed geochemical analyses. Rocks with a good to very good source potential are found in the six southernmost wells. Gas analyses also show that the area has a functioning source rock. Oil samples from well 7933/4-U-3 show a marine source rock, probably from the Triassic.

See the 2016 resource report and *Geological assessment of petroleum resources in eastern parts of Barents Sea North 2017* (NPD) for more information on the NPD's acquisition of geological data and mapping in unopened areas of the NCS.

CHAPTER **4**
PROFITABILITY OF EXPLORATION

Exploration has contributed substantial value to Norwegian society over the past decade, and has been profitable in all sea areas.



The NPD has calculated the profitability of exploration on the Norwegian continental shelf (NCS) over the past decade. The analysis shows that this activity has been profitable in all areas and has contributed substantial value to Norwegian society. Even very small discoveries can be profitable when tied back to existing infrastructure.

Exploration over the past decade has contributed substantial value to Norwegian society. That emerges from the NPD analysis, which presents the direct financial value creation from these activities in 2008-17. All profitability analyses are pre-tax calculations. The calculations do not take account of indirect economic effects such as the consequences of extending field production and spin-offs for the rest of the economy. Nor has the value of geological information acquired by exploration been quantified in this analysis. Its methodology and assumptions are described in fact box 4.1.

EXPLORATION AND COSTS DURING THE PERIOD

Exploration activity measured by number of wells spudded was high during the decade, with an annual average of 51 wells. It was at its highest in 2009, with 65 wells spudded, and lowest in 2017 with 36 (figure 4.2). The largest number of wildcats was drilled in the North Sea during the period.

Combined with strong oil and gas prices, the high level of activity during the period to 2015 contributed to a substantial growth in costs. The companies therefore initiated measures to reduce expenses, enhance operational efficiency and limit capital spending. The fall in oil prices reinforced the need for cost cuts.

The oil price decline and consequent capital rationalisation led to a sharp drop in exploration investment from 2016 (figure 4.3). Exploration expenses are outgoings incurred from the award of a production licence until a possible discovery is developed, and comprise spending on seismic surveys, wells, field evaluation and administration. Drilling represents the largest individual factor in total exploration costs. Rig hire is the largest component in expenditure.

Figure 4.4 shows the decline in drilling cost per well over the period.

This figure shows that costs per well are lowest in the North Sea and highest in the Barents Sea, al-

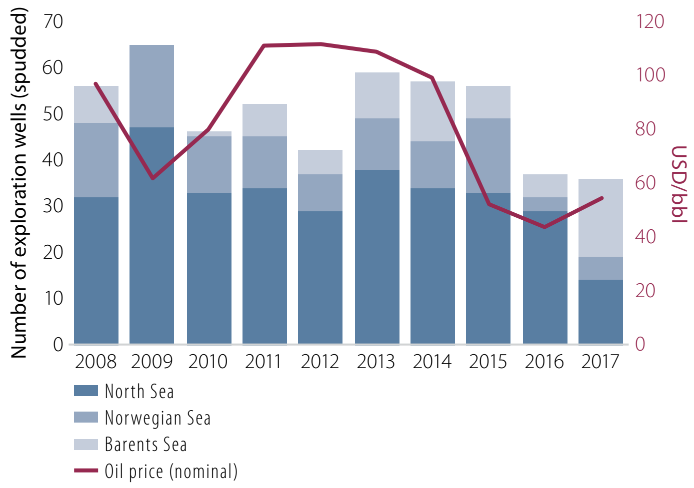


Figure 4.2 *Exploration wells spudded by area, 2008-17.*

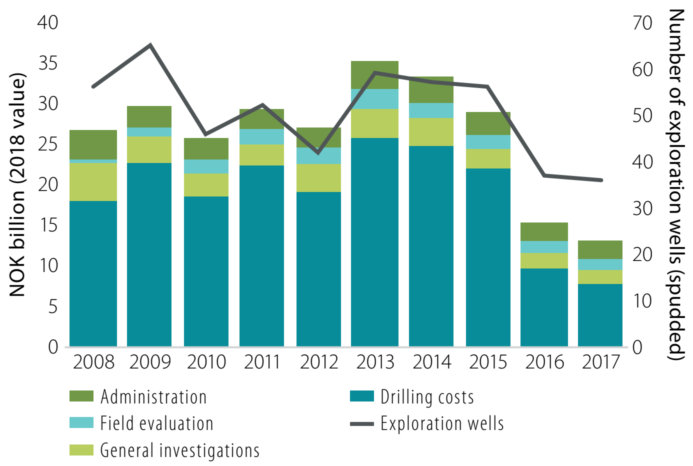


Figure 4.3 *Exploration costs and wells drilled, 2008-17.*

Fact box 4.1: *Methodology and assumptions*

This analysis covers all phases of the industry, from exploration to cessation and removal (figure 4.1).

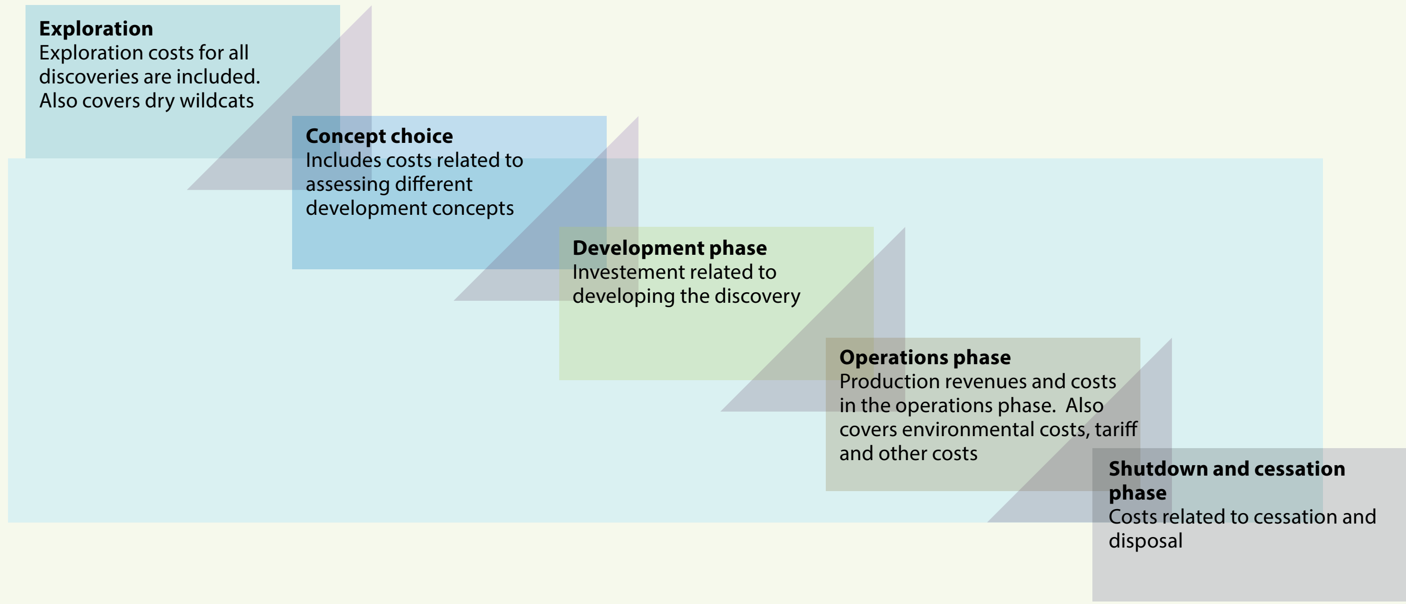


Figure 4.1 *Illustration of the various elements included in the analysis.*

The profitability of exploration is defined as calculated revenues from discoveries in the period less all expenses, including exploration and cessation costs. Exploration costs include both successful exploration and exploration which has failed to prove resources. Income and cost flows are discounted to the same year.

A total of 190 discoveries were made during the decade, of which 73 are categorised in resource class (RC) 6 – in other words, finds where recovery is not very likely (figure 1.10). The 7319/12-1 (Pingvin) and 7435/12-1 (Korpfjell) discoveries from 2014 and 2017 respectively are examples of finds placed in RC6 and thereby excluded from this analysis, which covers the remaining 117 discoveries.

Forty-eight of these are already in production (RC0-RC1), in the planning phase (RC2-RC4) or at a stage where recovery is likely but not clarified (RC5). Production and cost profiles reported by operators in connection with the revised national budget (RNB) have been applied in these cases. Examples include 16/1-9 Ivar Aasen from 2008, a field already on stream (RC0-RC1), 16/2-6 Johan Sverdrup from 2010, which has been clarified and is in the planning phase (RC2-RC4), and 7220/11-1 (Alta) from 2014, where production is likely but not clarified (RC5).

Thirty-nine of the discoveries in the analysis are either being or expected to be developed with other finds in coordinated developments (RC0-RC5). These discoveries are not reported separately, but form part of other overall profiles. To establish production and cost profiles per discovery, they are treated as a share of the overall profile reported by the operator for the RNB. The base estimate for calculated resources per discovery is used to compute this proportion. An example is provided by the discoveries in the Noaka area (north of Alvheim, Krafla and Askja).

The NPD has prepared separate production and cost profiles for 30 of the discoveries. Eleven of these are being or will be phased into coordinated developments initiated before the analysis period began, such as the 15/9-B-1 find from 2009 which is already on stream as part of the Sleipner Vest field. The remaining 19 discoveries had not been evaluated (RC7F) at 31 December 2017 and therefore lacked their own reporting, such as the 6707/10-3 (Ivory) find made in 2014 north-east of Aasta Hansteen.

NOK 523 per barrel has been assumed as the future oil price (in fixed 2018 value). At today's exchange rate with the US dollar, this corresponds to just under USD 65 per barrel. NOK 1.90 per scm has been assumed as the gas price. These figures accord with the RNB for 2018 (Report no 2 (2017-2018) to the Storting from the Ministry of Finance). Historical prices for oil, gas and natural gas liquids (NGL) are used for the period before 2018. Real discount rates of four and seven per cent are applied. Estimated spending for 2018 and beyond reflects the cost level in 2017 with a total uplift of 17.5 per cent up to 2029 (in accordance with the 2018 RNB).

The estimates for the profitability of exploration are uncertain. This reflects the inherent uncertainty of resource and cost estimates as well as of forward-looking price trends for oil and gas. No development decision has yet been taken for a significant proportion of the discoveries made in 2008-17. How far plans for these finds have advanced varies, so production and cost estimates are of differing maturity. Uncertainty about the start of production also has a substantial effect on present value. That applies particularly to discoveries in the Barents Sea, where little infrastructure is in place.

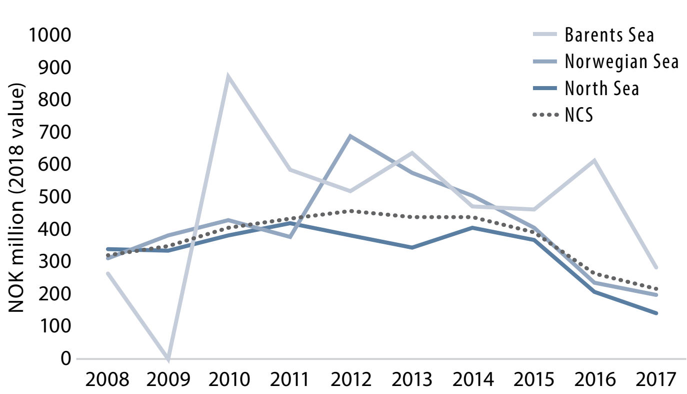


Figure 4.4 *Average exploration well cost (drilling expense per well) by area, 2008-17.*

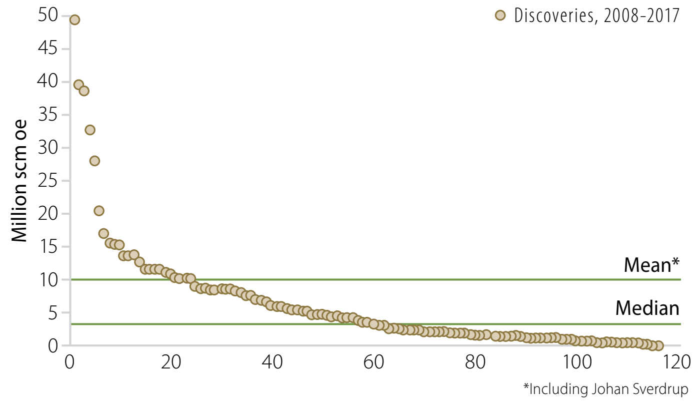


Figure 4.5 *Discovery size per find, 2008-17. The Johan Sverdrup discovery of about 400 million scm oe falls outside the scale used in the figure.*

though that varies somewhat over time.

The most important reason for the high cost of drilling in the Barents Sea over the past three years is several complicated wells.

It is important to emphasise that a significantly larger number of wells were drilled in the North Sea during the period than in the Barents Sea. This means that extreme values have a bigger effect on average cost in the latter area than in the former.

DISCOVERIES AND RESOURCE GROWTH DURING THE PERIOD

The 117 discoveries forming the basis for this analysis represent a total resource growth of about 1 150 million scm of oil equivalent (oe). Their size varies from the biggest (16/2-6 Johan Sverdrup) at roughly 400 million scm oe to the smallest with less than a million scm oe.

Figure 4.5 shows the size of the discoveries in the analysis. The mean discovery size (including 16/2-6 Johan Sverdrup) was about 10 million scm oe, with a median size of just under four million scm oe. A mean significantly higher than the median indicates that the biggest finds greatly exceeded the typical discovery size. In other words, they accounted for a high proportion of resource growth. That emerges clearly from figure 4.6.

VALUE CREATION IN THE PERIOD

The profitability of exploration is calculated with discount rates of four and seven per cent. Net present value at these rates is about NOK 930 billion and NOK 560 billion respectively. The overall net cash flow is estimated at almost NOK 1 600 billion. These estimates show that exploration has been profitable in all parts of the NCS (figure 4.7).

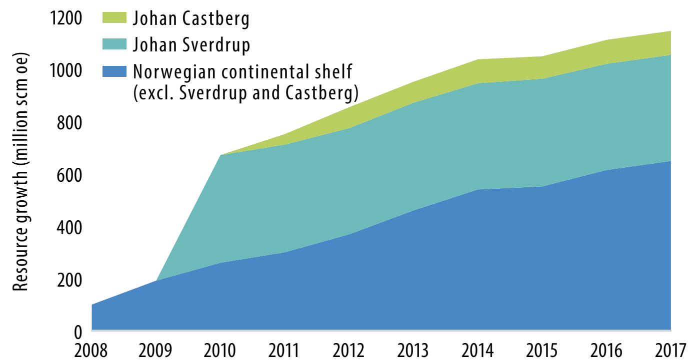


Figure 4.6 *Resource growth on the NCS in the 2008-17 analysis period.*

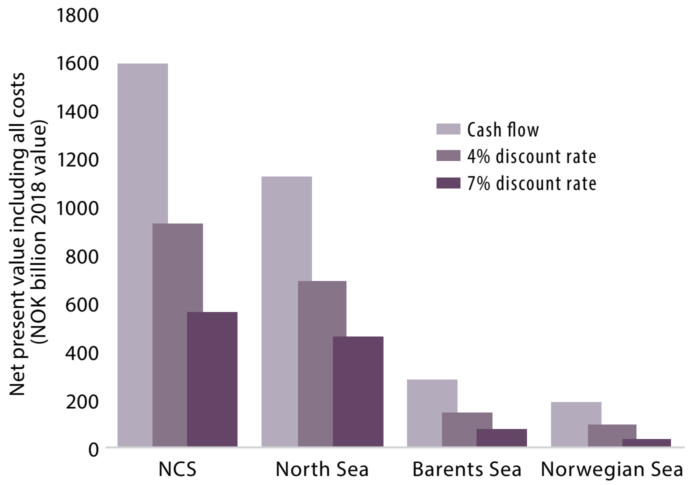


Figure 4.7 *Net present value of exploration in 2008-17 at various discount rates).*

VALUE CREATION FROM THE VARIOUS SEA AREAS

Figure 4.8 shows that the present value per krone spent on exploration is highest in the North Sea. NOK 1 000 invested in exploring this area yields a return of almost NOK 3 000. Exploration in the Barents and Norwegian Seas yields returns of NOK 2 100 and NOK 1 300 respectively for each NOK 1 000 invested. These values are additional to a seven per cent return.

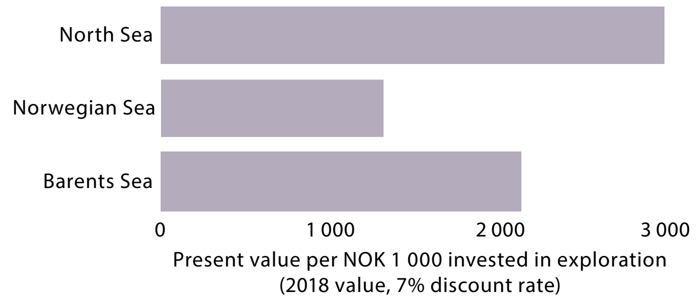


Figure 4.8 *Present value (seven per cent discount rate) per NOK 1 000 spent on exploration.*

Fact box 4.2: *25/1-11 R Skogul*

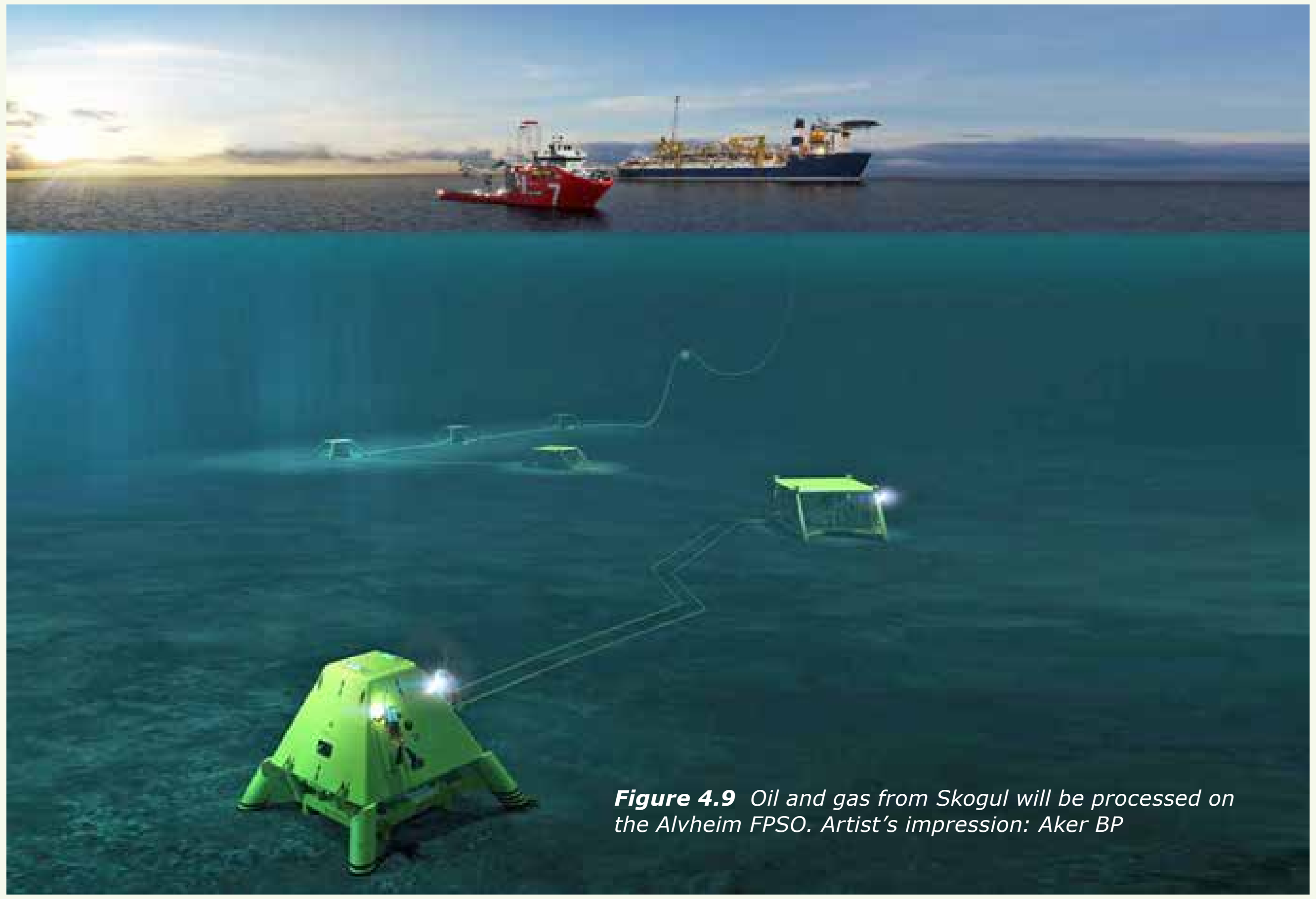


Figure 4.9 *Oil and gas from Skogul will be processed on the Alvheim FPSO. Artist's impression: Aker BP*

Utilising existing infrastructure can also make very small discoveries commercial. This type of development is an important part of the future on a maturing NCS. An example of this is Skogul, which was proven in 2010. Previously called Storklakken, this discovery in the central part of Norway's North Sea sector will be one of the smallest fields on the NCS with a reserve base of roughly 1.5 million scm (about 9.4 million barrels) of oil. Skogul is to be developed with a bilateral well drilled from a subsea template tied back to the installations on the Vilje field, with production piped on from there to the Alvheim field. Oil and gas from Skogul will be processed on Alvheim's floating production, storage and offloading (FPSO) unit. Alvheim is also the field centre for Volund and Bøyla. Plans call for Skogul to come on stream in the first quarter of 2020, with Aker BP as operator. Investment is expected to be about NOK 1.5 billion. The discovery would not have been commercial without the tie-in to existing infrastructure.

SENSITIVITY ANALYSIS

The NPD has analysed the sensitivity of profitability to changes in oil and gas prices.

A 20 per cent increase in these prices would yield a net present value of almost NOK 900 billion at a seven per cent discount rate. A 20 per cent decrease would yield a net present value of roughly NOK 250 billion (figure 4.10). The cost level is the same in both calculations.

The profitability analysis has also been tested for a corresponding increase in operating expenses, which include environmental costs. This would not have a decisive effect on the results.

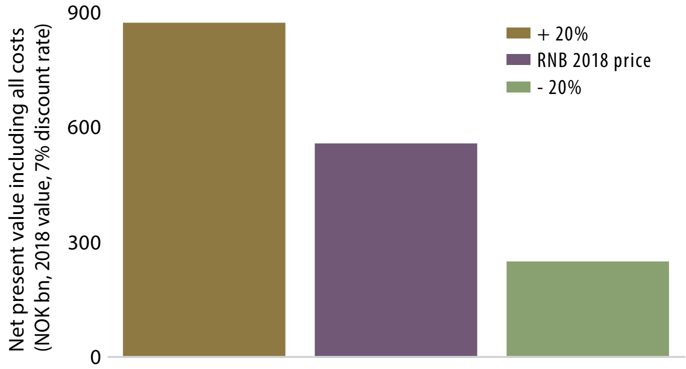
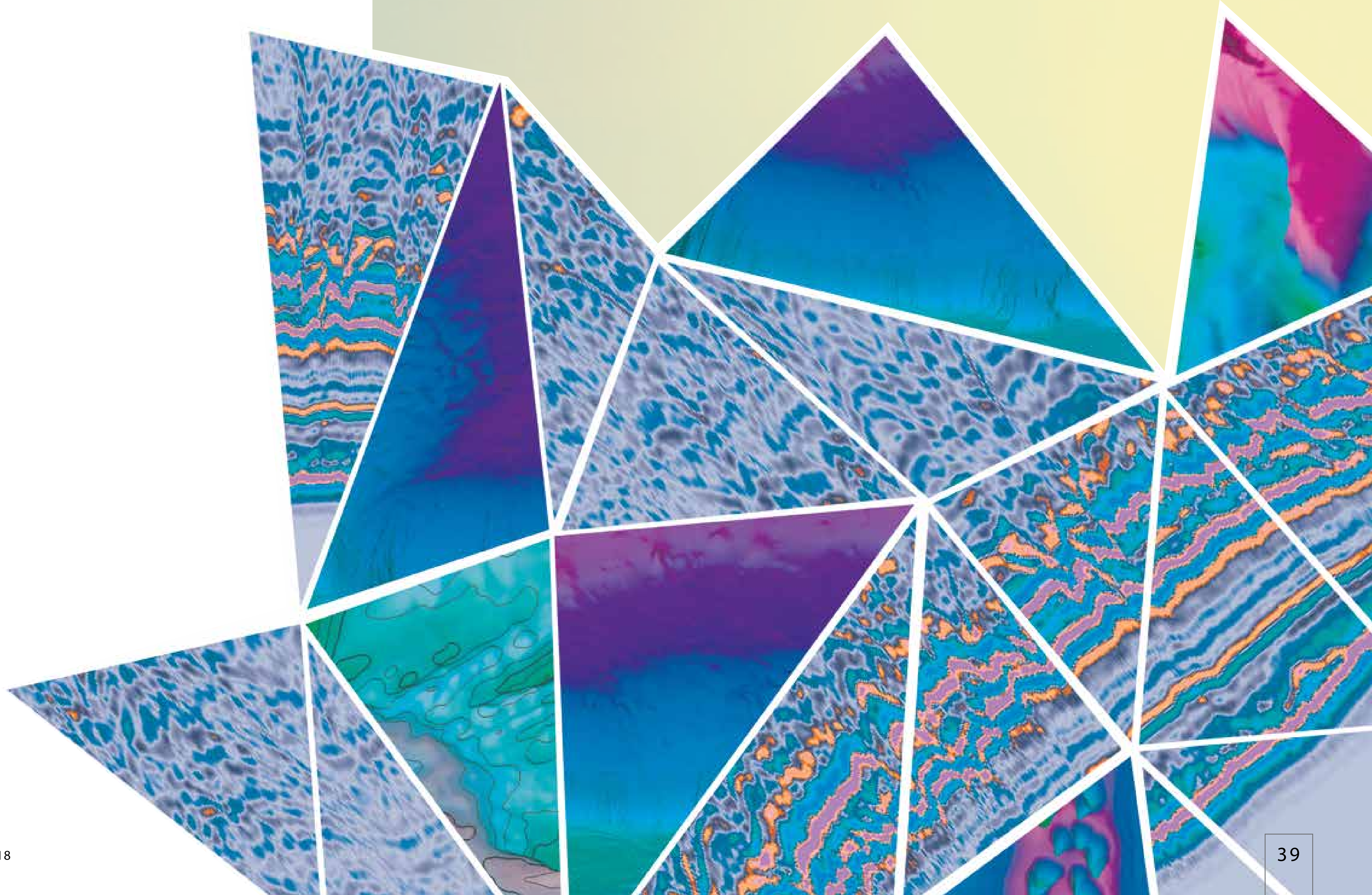


Figure 4.10 *Net present value of exploration in 2008-17 at various prices and a discount rate of seven per cent.*

CHAPTER 5 PLAYER PICTURE IN THE EXPLORATION PHASE

A broad variety of companies creates competition, which promotes efficiency and value creation in the exploration phase.



CHAPTER 5
PLAYER PICTURE IN THE EXPLORATION PHASE

A broad variety of players creates competition and different play and prospect concepts, which promote efficiency and value creation. Even though the number of players has declined somewhat since 2013, diversity remains high in the exploration phase. Through a combination of active and experienced large and medium-sized companies, focused exploration companies and new company creations for both exploration and production, the conditions are in place to continue efficiently exploring the resource potential on the Norwegian continental shelf (NCS).

As the NCS has become a more mature petroleum province, facilitating a player picture which ensures efficient exploration, development of discoveries and good resource management have been important for the government.

A broad variety of players creates competition, which promotes exploration efficiency. It also ensures a greater diversity of ideas and interest in different play and prospect concepts, and the adoption of alternative technologies and working methods.

DEVELOPMENT OF THE PLAYER PICTURE

Exploration was initially dominated by a limited number of players, primarily large Norwegian and international companies.[9] The number and variety of these players has increased from the mid-2000s, partly as a result of purposeful measures to create greater diversity (figure 5.1 and table 5.1). These included prequalification of new operators and licensees in 2000, the awards in predefined areas (APA) scheme in 2003 and the reimbursement system for exploration costs in 2005.

CHANGING OF THE GUARD?

The position in the industry over the past three years, with falling oil prices, declining exploration and low resource growth, has led to changes in the number of players. While 56 companies had interests in production licences on the NCS in 2013, that number had declined in the wake of the 2014 oil price fall to 43 in 2017 (figure 5.2).

This reduction has been greatest for European gas/power companies and small companies. Several of the European gas/power players have opted to withdraw from upstream activities in order to concentrate on the downstream sector and renewable energy. They have accordingly reduced or disposed of their interests. Dong (2017) and Engie (2018), for example, sold their oil and gas operations to medium-sized companies Ineos and Neptune respectively, while Centrica's oil and gas business and Norwegian operations at Bayerngas have been merged to create Spirit Energy.

Large Norwegian companies	Statoil, Petoro
Majors	Chevron, ConocoPhillips, Eni, ExxonMobil, Shell, Total
European gas/power companies	Edison, Engie, PGNiG, Spirit Energy, VNG
Medium-sized companies	Aker BP, Capricorn, DEA, DNO, Idemitsu, Ineos, Inpex, Kufpec, Lotus, Lukoil, Lundin, Maersk, MOL, OMV, Point Resources, Repsol, Suncor, Wintershall
Small companies	CapeOmega, Concedo, Faroe, Fortis, Lime, M Vest, Okea, Pandion, Petrolia, Production Energy, Skagen 44, Wellesley

Table 5.1 *Licensees at 31 December 2017 by company category.*

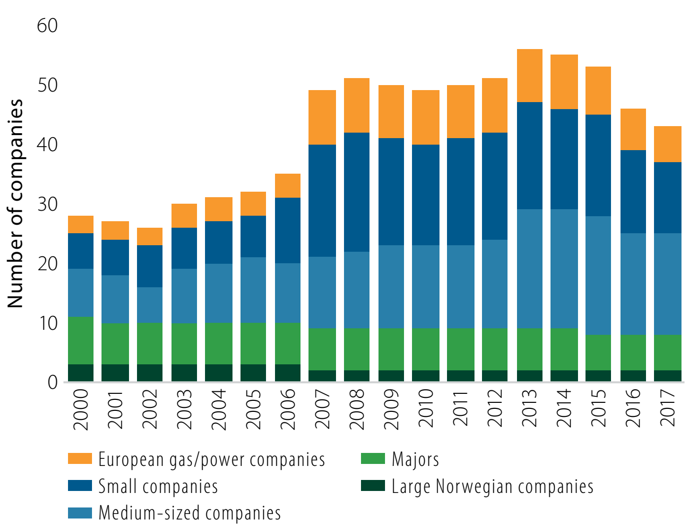


Figure 5.1 *Companies on the NCS, 2000-17.*

[9] This report uses the term "players" for licensees (operators and partners) in production licences.

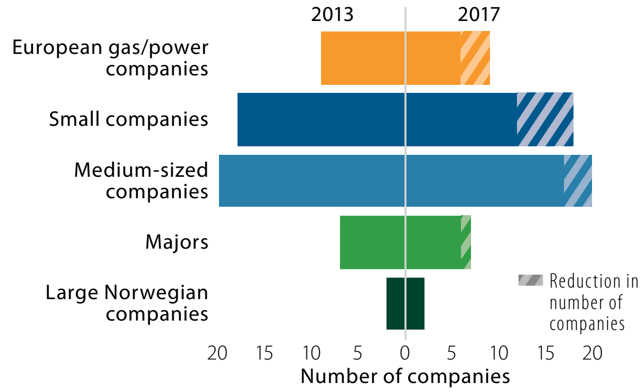


Figure 5.2 *Changes to the player picture since 2013.*

Among small companies, several have pulled out or been acquired by others. In addition, Pure E&P, Core Energy and Spike Exploration merged in 2016 to establish Point Resources.

Where medium-sized companies are concerned, America's Hess sold its entire Norwegian business to Aker BP.

Of the majors, BP Norge merged with Det Norske Oljeselskap to establish Aker BP and Total acquired Maersk's oil and gas business. ExxonMobil sold its interests in the Balder and Ringhorne Øst fields, which it had operated, to Point Resources in 2017. That left the company without operatorships for producing fields on the NCS. This sale promoted Point Resources into the medium-sized company category.

In recent years, enterprises financed by private equity (PE) companies or funds have made substantial acquisitions on the NCS and the UK continental shelf.[10] Transaction activity in 2017 indicates that PE-financed companies have great faith in the NCS (figure 5.3). This category includes two medium-sized and five small companies.

Figure 5.3 also shows that the remaining small and medium-sized companies, European gas/power companies and majors are selling more interests than they acquire.

The majors have been important for developments on the NCS since the 1960s. Such enterprises accounted for the bulk of all exploration off Norway in the first 10-15 years. They had the expertise, capacity, financial strength and experience to develop a number of the initial fields, and contributed simultaneously to building up expertise in the Norwegian oil and gas industry.

These companies have drilled fewer exploration wells in recent years, and several have reduced their holdings through farm-outs. Reasons for this could include lack of exploration interest and success, a mature portfolio, optimisation of their international portfolios and a need to increase cash flow.

While some of the majors have reduced their operations, other players have been more active in the

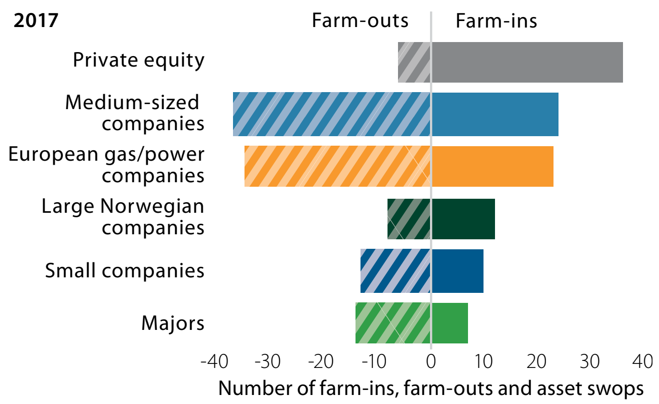


Figure 5.3 *Farm-ins, farm-outs and swops of licence interests on the NCS in 2017.*

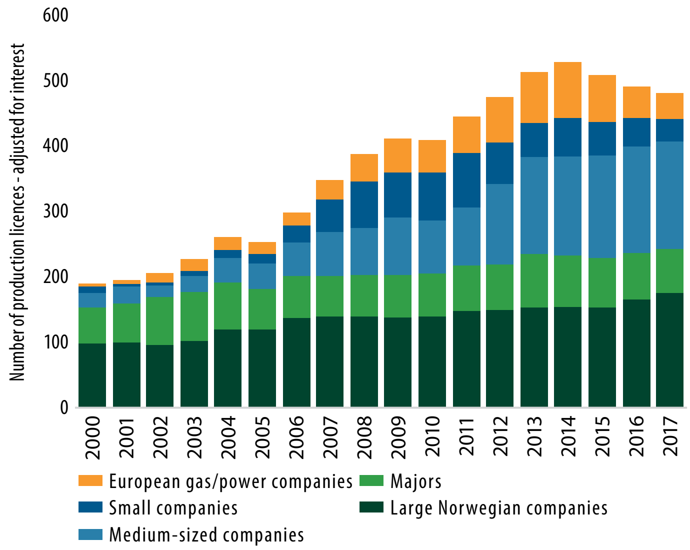


Figure 5.4 *Production licences by company category in 2000-17.*

[10] PE is a collective term for a special type of fund/company which invests in unlisted enterprises. See Report no 7 (2008-2009) to the Storting on an innovative and sustainable Norway.

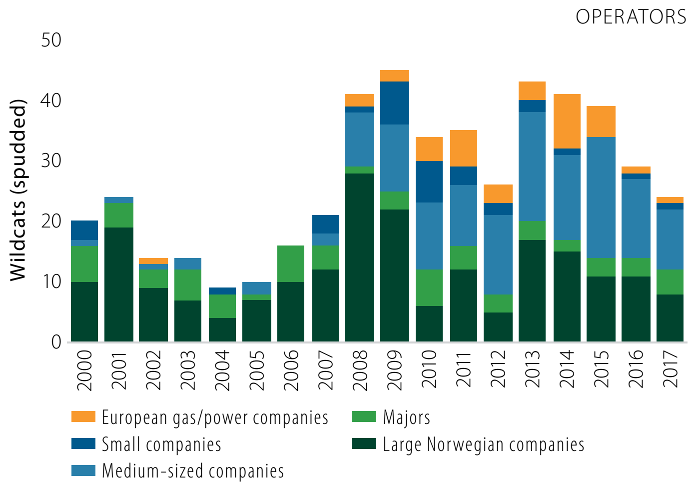


Figure 5.5 Wildcats spudded by company category (operators).

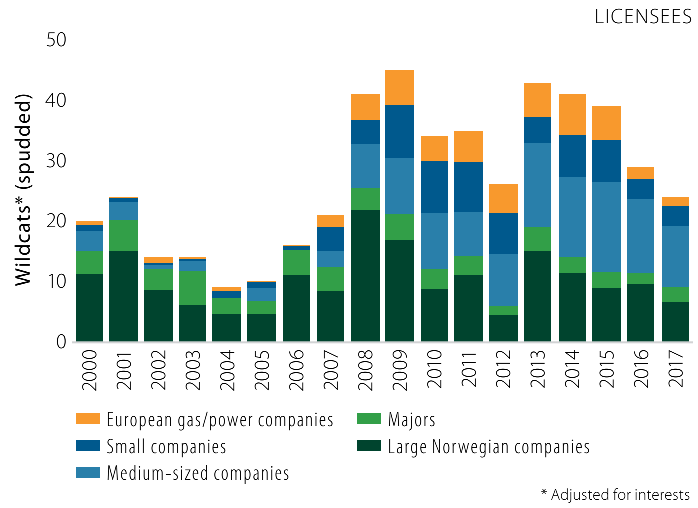


Figure 5.6 Wildcats spudded by company category (licensees).

most recent licensing rounds. A number of them have thereby strengthened their position. That applies particularly to medium-sized companies making an active commitment to the NCS.

Exploration in 2018 is expected to increase slightly from the two preceding years. The continued combination of active and experienced large and medium-sized companies, more focused exploration companies and new company creations for both exploration and production means that diversity and competition can contribute to efficient exploration of the NCS.

EXPLORATION ACTIVITY BY COMPANY TYPE

The number of production licences has more than doubled since 2000 (figure 5.4). Medium-sized companies have seen the biggest increase in their holdings, and accounted together with large Norwegian companies for about 70 per cent of licence interests in 2017.

Investment and wells drilled by companies provide some indication of how actively they participate in exploration.

In 2000-07, the biggest contributors to exploration – both as operators and licensees – were large Norwegian companies and majors (figures 5.5, 5.6 and 5.7). In line with the growth in player numbers, exploration increased substantially from 2007 and the player picture became more diversified. Since 2007, medium-sized and large Norwegian companies have been the most active explorers. European gas/power and small companies have also contributed, but had the biggest reduction in exploration activity over the past two-three years.

Exploration investment correlates strongly with exploration wells drilled. The medium-sized companies and large Norwegian companies have therefore dominated the investment picture over the past decade (figure 5.7). Following the oil price slump in 2014, exploration investment fell substantially and was down to about a third of the peak 2013 level by 2017. The group of European gas/power companies accounted for the largest percentage decline.

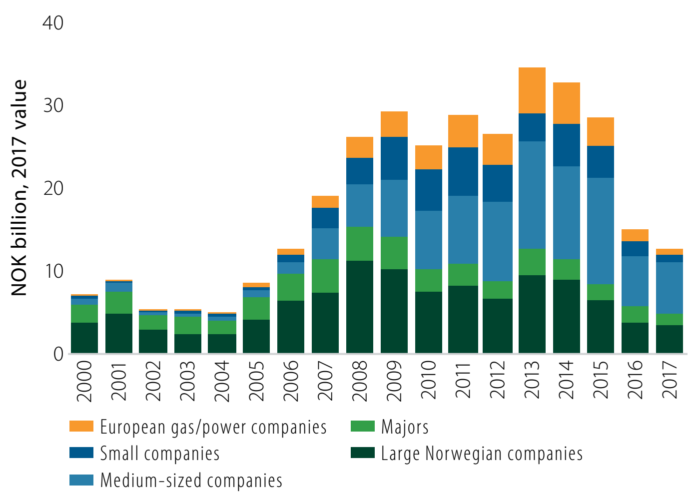


Figure 5.7 Investment in exploration in 2000-17 by company category (licensees).

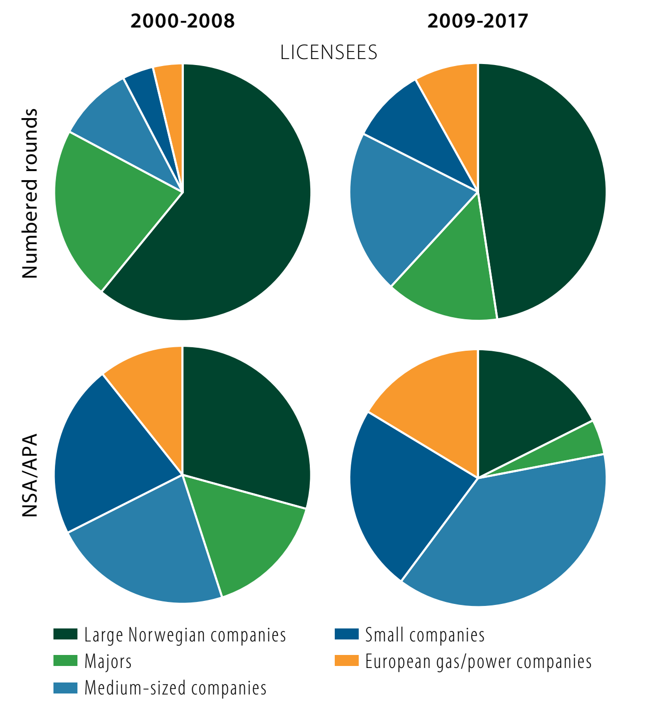


Figure 5.8 Proportion of wildcats drilled by company category (licensees) in licences awarded through numbered and APA rounds respectively in 2000-08 and 2009-17.

PLAYER PICTURE IN APA AND NUMBERED ROUNDS

The increase in both number and variety of participants has led to a more diversified player picture where exploration is concerned. Figure 5.8 shows greater diversity in drilling activity during 2009-17 than in 2000-08 for both APA and numbered rounds.

Large Norwegian companies and majors drilled the majority of the wildcats in production licences awarded in numbered rounds during the first of these periods. During the second, the largest proportion of wells was drilled by large Norwegian and medium-sized companies.

Where acreage awarded in APA rounds is concerned, large Norwegian companies and majors accounted for about 45 per cent of wildcats in 2000-08. That proportion was reduced to about 20 per cent in 2009-17, when medium-sized and small companies accounted for around 60 per cent of drilling activity in the APA area.

EXPLORATION RESULTS FOR THE PAST FIVE YEARS

Exploration results depend on a number of factors – prospectivity in the acreage awarded, where activity takes place, and its scope and quality. Figures 5.9-5.10 present the relationship between the number of wildcats and resource growth over the past five years.

Medium-sized companies drilled most of the wildcats in 2013-17, and had the biggest resource growth. The growth in resources was greatest in the Barents Sea and included such discoveries as 7324/8-1 (Wisting), 7220/11-1 (Alta), 7120/1-3 (Gohta) and 7219/12-1 (Filicudi).

Medium-sized, large Norwegian and small companies showed relatively high resource growth per wildcat. Majors and European gas/power companies had the lowest resource growth and relatively low resource growth per wildcat. However, majors and large Norwegian companies had the highest success rates (figure 5.11).

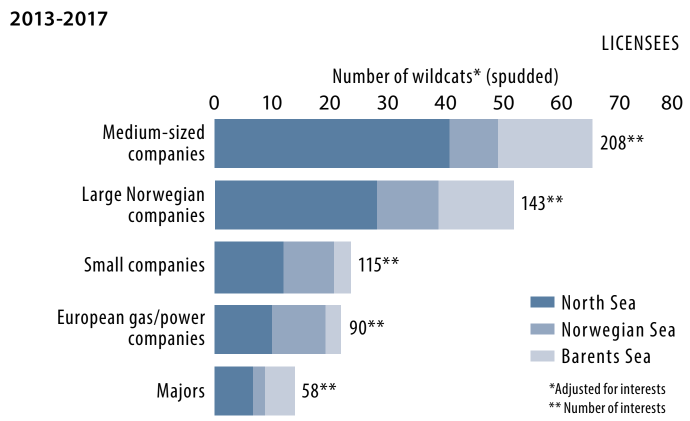


Figure 5.9 Wildcats drilled in 2013-17 by company category (licensees).

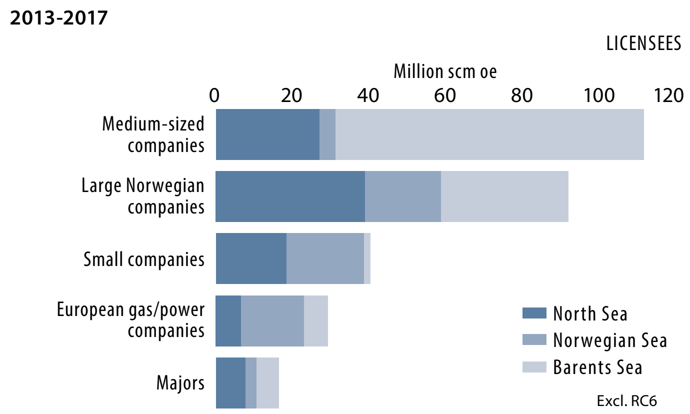


Figure 5.10 Resource growth (excl resource class 6) in 2013-17 by company category (licensees).

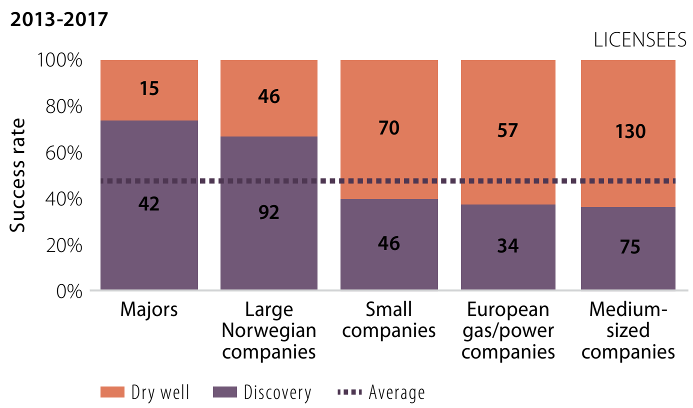


Figure 5.11 Success rate in 2013-17 by company category (licensees).

LONG-TERM PERSPECTIVE

At 31 December 2017, large Norwegian companies and majors still had the biggest remaining reserves (resources in fields and discoveries sanctioned for production) on the NCS (figure 5.12). However, medium-sized companies strengthened their position and were the player category with the biggest growth in licences and the highest exploration activity in recent years. This yielded a number of finds and led to increases for both reserves and resources in discoveries still not sanctioned for development. Together with large Norwegian companies, this category accounts for almost 70 per cent of the resources in discoveries still not sanctioned for development.

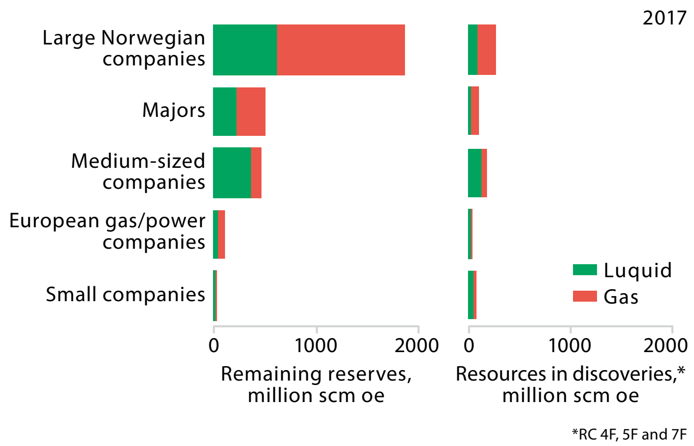
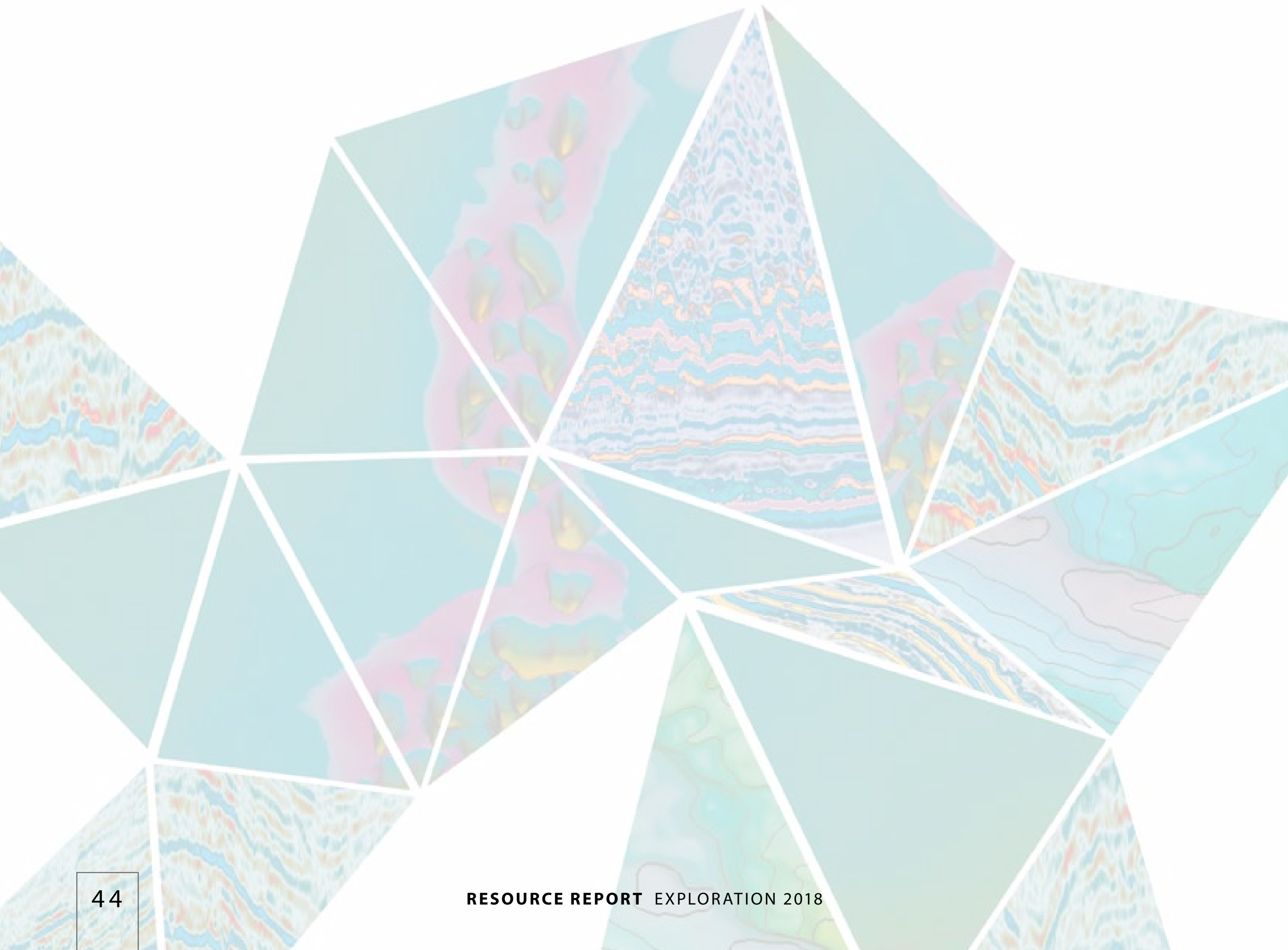
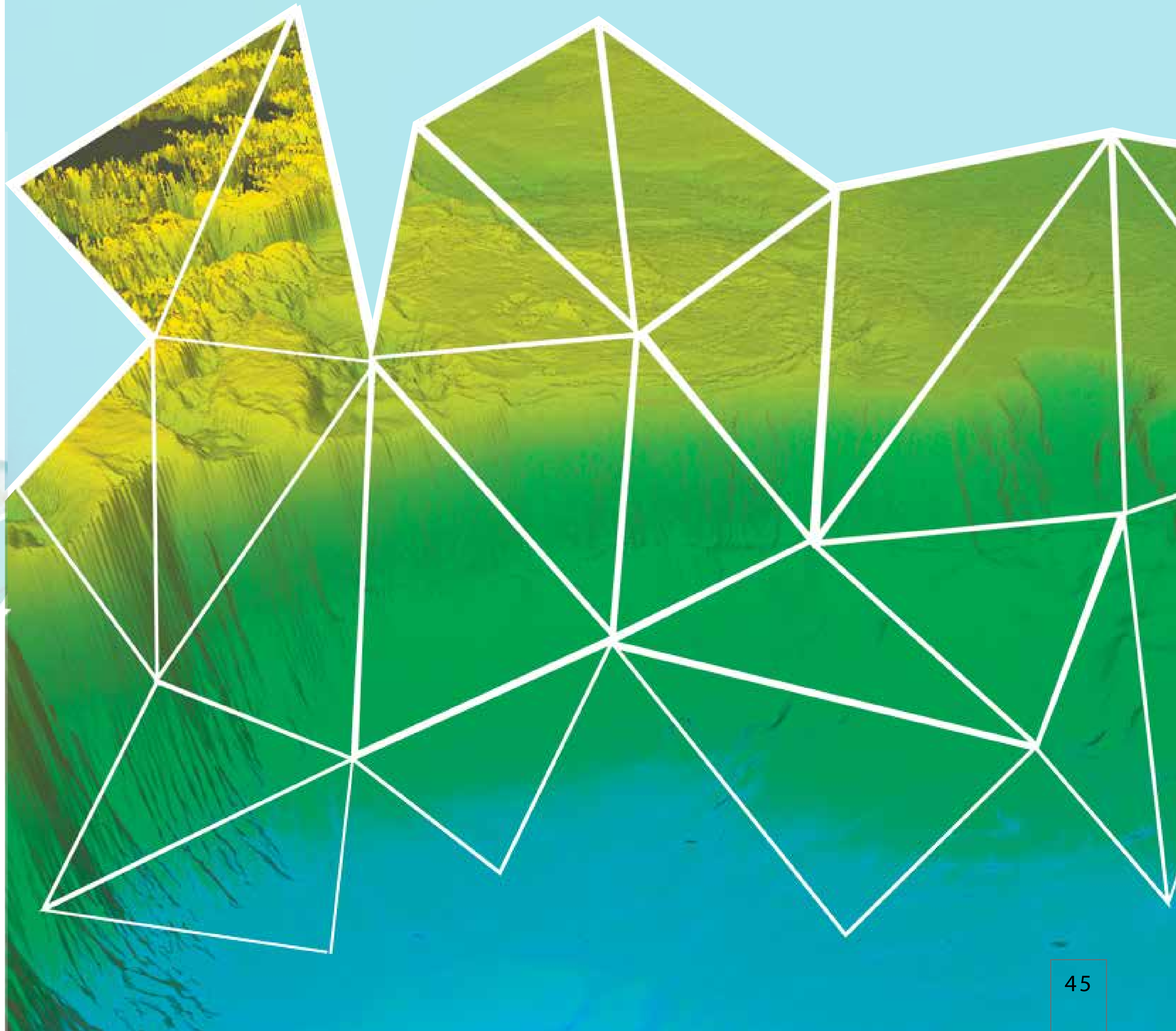


Figure 5.12 *Remaining reserves and resources in discoveries on the NCS at 31 December 2017 by oil and gas.*



CHAPTER **6**
NEW EXPLORATION TECHNOLOGY AND WORK PROCESSES

Better data, increased knowledge and innovative technology reduce risk and create value.



Finding oil and gas deposits is becoming increasingly difficult. Technological advances have provided better data and improved tools, contributing to new understanding of the geology and making it possible to identify new play and prospect concepts. That could help to reduce exploration risk and make further discoveries. The industry must exploit the possibilities offered by integrating geoscience expertise with digital technology to identify new resources.

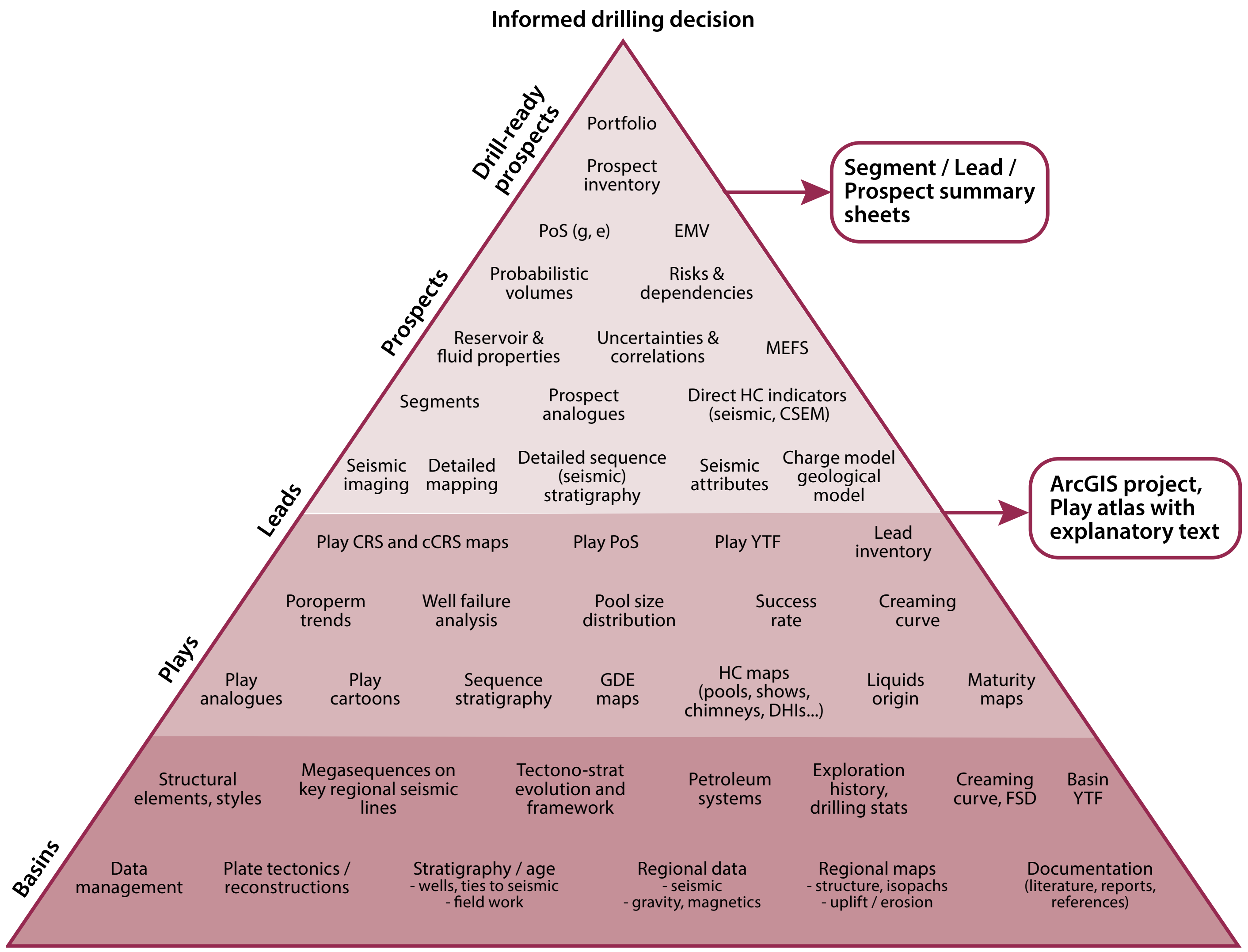


Figure 6.1 *Illustration of the exploration process. Based on Milkov, 2015.*[11]

[11] Milkov, A V (2015): "Risk tables for less biased and more consistent estimation of probability of geological success (PoS) for segments with conventional oil and gas prospective resources". *Earth-Science Reviews*, vol 150, pp 453–476.

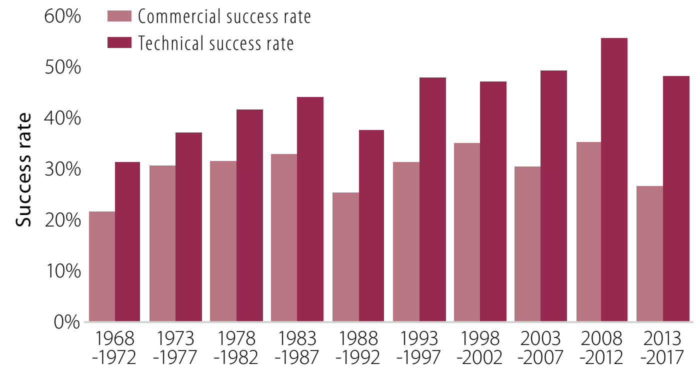


Figure 6.2 *Development of technical and commercial success rates (averages at five-year intervals).*

Technological progress, improved mapping, more data and greater understanding of the geology can contribute to reducing exploration risk and making further discoveries. Technology development may also cut the cost of hunting for oil and gas, and thereby make more and smaller prospects interesting to explore. Both these considerations could help to expand the resource base on the Norwegian continental shelf (NCS).

The basis for discovering and developing oil and gas resources is created through work to understand the sub-surface, which draws primarily on the geosciences. These disciplines are making constant progress, supplemented by innovative technology and new work processes.

Figure 6.1 provides an overview of the data acquired, generated or evaluated in order to take knowledge-based exploration decisions.

Exploration includes understanding where and how oil and gas form, migrate, become captured in traps and accumulate in sub-surface reservoirs. Good exploration decisions which lead to discoveries require technology and geophysical methods which deliver high-quality images of the sub-surface. Seismic data acquisition is crucial here, while electromagnetic methods and other technologies can serve as valuable supplements.

Advances in seismic data acquisition and processing have led to a marked improvement in sub-surface imaging during recent years. Combined with developments in the geosciences, this has equipped geologists and geophysicists to build good models of the sub-surface and thereby identify new exploration opportunities. That can encourage increased drilling and yield more discoveries.

The development of the technical success rate shows that exploration has become steadily more effective (figure 6.2). This rate has remained high since the early 1990s. As discovery size declines, the gap between the technical and commercial success rates is tending to increase.

In order to improve understanding of how progress with technology and geological methods has contributed to efficient exploration, the NPD carried out a study in collaboration with consultant Westwood Global Energy Group. This identified a number of important areas within a wider exploration technology concept, such as data acquisition, geosciences and working methods. These have been and will continue to be important for exploration on the NCS. The NPD has grouped these under six main headings: (1) seismic data acquisition, imaging and analysis, (2) electromagnetic methods, (3) basin modelling, (4) drilling technology, (5) the human factor and (6) visualisation, Big Data and machine learning.

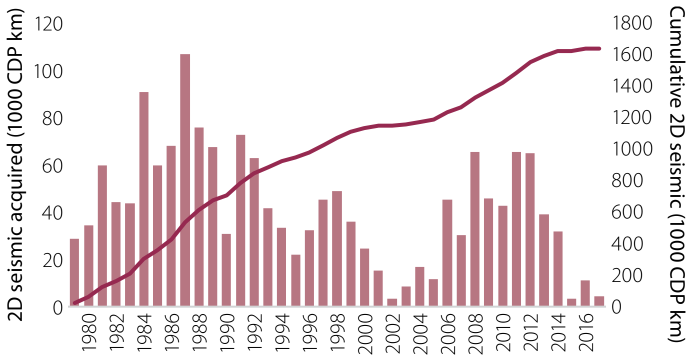


***Figure 6.3** Acquisition of 2D seismic data on the NCS.*

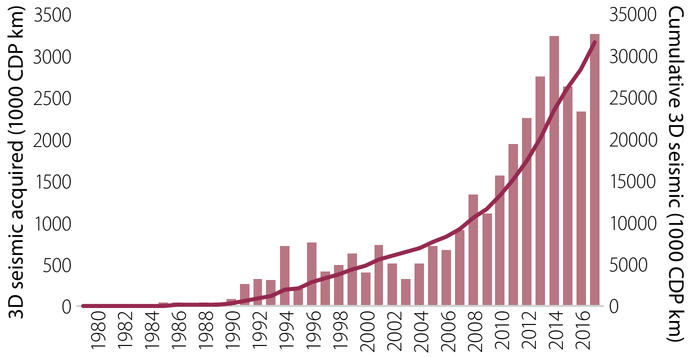


***Figure 6.4** Acquisition of 3D seismic data on the NCS.*

***FACT BOX 6.1:** Seismic data acquisition on the NCS*

Seismic (geophysical) survey data are acquired by transmitting sound waves from a source about five to 10 metres below the sea surface. These waves travel through the sub-surface strata and are reflected back to sensors located just under the sea surface, on the seabed or down a well. The data are then processed to form an image of the sub-surface geology. Seismic mapping of the NCS began in 1962.

Various types of seismic surveys are conducted:

2D seismic data are acquired with a single hydrophone streamer. This yields a two-dimensional seismic line/cross-section of the sub-surface.

3D seismic data are acquired using several streamers to provide a three-dimensional and detailed image of the sub-surface.

Broadband seismic surveying is a technology which utilises a broader spectrum of frequencies than conventional methods. The very low frequencies, in particular, provide a much clearer image of sub-surface structures. Combined with seismic data processing, this method can supply more detailed information with a sharper resolution and improved depiction of the sub-surface.

SEISMIC DATA ACQUISITION, IMAGING AND ANALYSIS

SEISMIC DATA ACQUISITION

Seismic data (fact box 6.1) are used to map geological conditions beneath the seabed, and are fundamental in studying opportunities for finding petroleum. Virtually all decisions about exploration drilling today are based on three-dimensional (3D) seismic surveys.

At 31 December 2016, 1 600 000 common depth point (CDP) kilometres of two-dimensional (2D) seismic data had been acquired on the NCS (figure 6.3). Such acquisition has declined significantly in recent years.

The first commercial 3D seismic surveys on the NCS were conducted in the late 1970s. Discovery well 30/6-17 near the Oseberg field in 1985 was the first wildcat drilled on the basis of 3D data.

The scope of acquired 3D seismic data varied little in 1994-2006, but increased substantially between 2007-08 and 2014 (figure 6.4).

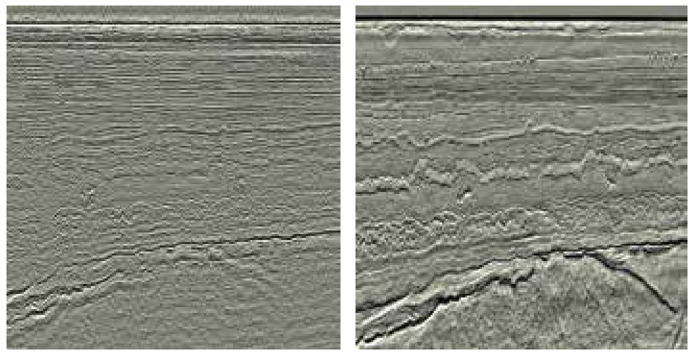


***Figure 6.5** An example of the improvement in seismic data quality between 2007 (left) and 2013 (right). From the Edvard Grieg field. Images: WesternGeco*

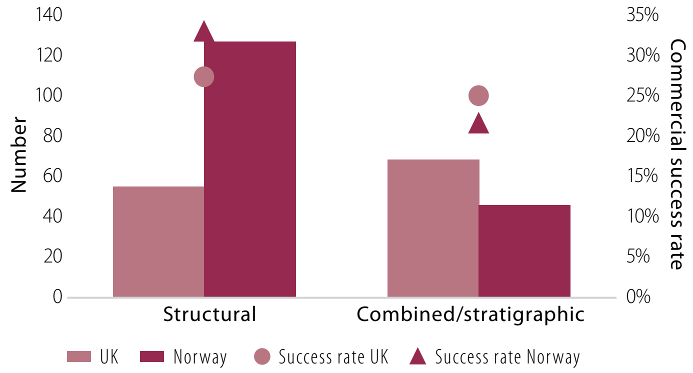


***Figure 6.6** Trap types and commercial success rates in Norway and the UK, 2008-17. Source: Westwood*

IMPROVED IMAGING

Seismic data quality has gradually improved in recent years (figure 6.5). Advances have occurred in both survey methods and data processing. The biggest technological leap since 2000 has been the development and implementation of broadband seismic surveying (fact box 6.1). Substantial improvements have also been made to processing algorithms, especially with regard to 3D migration. This has made images sharper and positioning more exact, particularly in areas with complex geology.

Large parts of the NCS, especially the mature areas of the North and Norwegian Seas, have been covered by broadband 3D seismic surveys in recent years. Combined with increased computing power and new interpretation and visualisation tools, this has made it possible to identify new exploration opportunities – even in areas already investigated.

Many of these opportunities are located close to existing infrastructure and can represent substantial value through rapid phasing-in. Resources around today's fields must be identified while infrastructure is still in place. New seismic data and approaches could also extend the producing life of old fields and lay the basis for decisions on developing stranded discoveries.

The application of broadband technology will probably increase in scope. Developing improved algorithms for processing seismic data is expected to continue, and allow the industry to achieve better results by reprocessing existing data sets.

Improved seismic imaging combined with better seismic data analysis could also help to identify more stratigraphic traps. Great interest has been shown in recent years in injectites, one type of such formations. Examples include the 24/9-5 Volund, 25/4-10 S (Viper) and 25/7-5 Kobra discoveries. Prospects with stratigraphic trap types have been less explored on the NCS than on the more mature UK continental shelf (figure 6.6). The British success rate in this kind of prospect has also been higher. That might indicate a potential on the NCS which has yet to be realised, and exchanging experience between the UK continental shelf and the NCS could be important.

SEISMIC DATA ANALYSIS

The increased scope of acquired seismic data and improvements to its quality since 1990 have contributed to the development of new and better analysis tools and methods. These have resulted in big advances in quantitative seismic data analysis. Increased computing power has also made the calculations substantially faster and more detailed.

That has opened the way to more advanced analysis techniques for seismic data, particularly with amplitude versus offset (AVO) and seismic inversion procedures.

According to Westwood, it appears that the industry often fails to exploit all the opportunities offered by integrating seismic data analysis with geological knowledge and experience. These methods need to become better integrated in the geological evaluation process (figure 6.1).

Greater integration means that people with different technical specialisations must collaborate in new ways and much more closely than before. The technology and methods represent useful and advanced tools. Combining the technology with geological experience and knowledge boosts the probability of making the big discoveries.

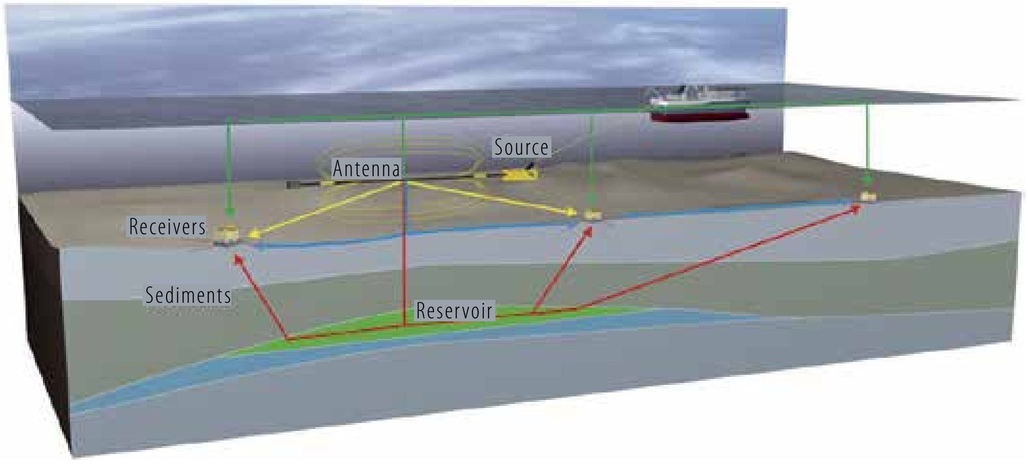


***Figure 6.7** Electromagnetic methods. Artist's impression: EMGS*

ELECTROMAGNETIC METHODS

The controlled source electromagnetic (CSEM) method was introduced and commercialised soon after 2000. This approach allows electrical resistance in rocks and wells to be measured and compared. High electrical resistance could, for instance, indicate the presence of hydrocarbons. The challenge is that other components in the sub-surface can give a similar response in a number of areas. Salt and rocks with a substantial organic content, for example, offer high resistance and can give a "false" response. The accuracy of this method is therefore a bit variable, and good calibration with existing fields and discoveries could be crucial in improving it (figure 6.7).

Since the introduction of electromagnetic (EM) methods, lack of accuracy at times has meant that part of the industry is sceptical about their benefits.

Data acquired in this way have demonstrated good accuracy in parts of the Barents Sea, particularly where the reservoirs are at shallow depths. The 7324/8-1 (Wisting) discovery lies just 250 metres beneath the seabed, which is ideal for measuring EM response. Such data have been useful in this area.

The technology has been further developed in recent years with the use of 3D acquisition, improved inversion techniques and more powerful sources which can reach deeper reservoirs. CSEM is expected to become more widely used both on the NCS and internationally.

BASIN MODELLING

A substantial increase has occurred in calculation capacity for 3D basin modelling (figure 6.8).

The ability to measure geochemical parameters has made great strides. That includes gas analyses during drilling, more detailed measurement of biomarkers and the implementation of kerogen analyses with the aid of scanning electron microscopy (SEM).

Greater computing power and large data volumes will probably contribute to developing and improving the opportunities offered by 3D basin modelling. In geochemistry, new methods of analysing gas in drilling fluids will be important for improved understanding of hydrocarbon migration.

Increased availability of high-quality seismic data from certain basins in other parts of the world has enhanced understanding of sedimentary sub-surface systems. This insight and knowledge are being applied on the NCS, particularly in connection with plays in deepwater areas.

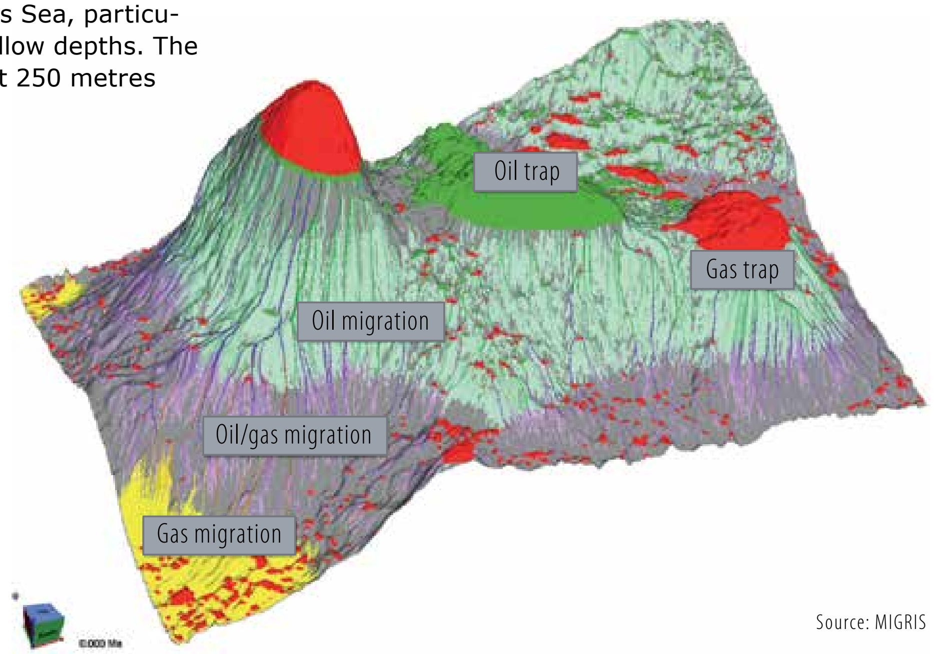


***Figure 6.8** Visualisation of 3D basin modelling.*

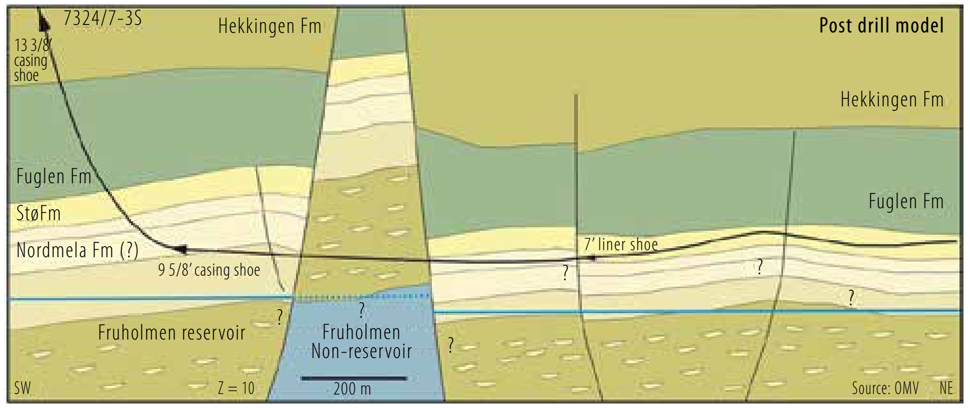


***Figure 6.9** Highly deviated drilling on the 7324/8-1 (Wisting) oil discovery. Appraisal well 7324/7-3 S.*

DRILLING TECHNOLOGY

Technological advances mean that neither water depth nor pressure present obstacles to safe drilling of exploration wells.

These are now being drilled in other parts of the world in waters up to 4 000 metres deep. Wildcat 6403/6-1 in the Norwegian Sea currently holds the water-depth record on the NCS. It was drilled for Statoil in 1 721 metres of water during 2006 by the *Eirik Raude* rig.

Today's drilling technology and blowout preventers (BOPs) make it possible to drill high pressure, high temperature (HPHT) wells[12] with pressures as high as 1 050 bar.

Another technology, highly deviated drilling, is now standard practice in field development and makes it possible to investigate exploration targets from existing infrastructure and to tie back possible discoveries for swift production.

Several discoveries have been made only about 200 metres beneath the seabed in recent years. The best-known example is 7324/8-1 (Wisting) in the Barents Sea, which was drilled 250 metres beneath the seabed. Until operator OMV completed a successful highly deviated well in 2017, doubts were expressed about whether a field development could be based on horizontal wells in such shallow reservoirs (figure 6.9).

THE HUMAN FACTOR

Studies conducted by government regulators such as the NPD and the UK's Oil and Gas Authority (OGA) show that oil companies overestimate the volume in prospects, both in their licensing-round applications and when taking drilling decisions. The uncertainty range for these estimates is also often too small.

The oil companies also have a tendency to underestimate the probability of success. Taken together, these factors yield more but smaller discoveries than prognosed. Many oil companies have conducted studies drawing on their own data to publish similar conclusions, often based on global data sets. The issue is not new, and was described in the NPD's resource report as early as 1997 (chapter 7).

The reasons for this problem are complex, but probably relate more to psychology than to geological knowledge, methodology, software and data. Nor is the issue unique to prospect evaluation. It can arise in all circumstances where people take decisions or make prognoses based on their own assessment of available information. Psychologists Daniel Kahneman and Amos Tversky wrote several articles on the subject in the 1970s and 1980s. They came up with a number of examples of cognitive bias, which results from the way people assess information. Many other types of bias than those described by Kahneman and Tversky have since been identified.

Before biases can be eliminated, they must be recognised and an understanding established of why and how they arise. Many companies are working sys-

[12] Defined as wells with a pressure above 690 bar and/or a bottomhole temperature of 150°C.

tematically today to check their estimates against the actual results. Most of them also have various groups for peer assistance in the evaluation phase and quality assurance teams with experienced personnel who assess evaluations across the company. In addition, many provide systematic training on prospect evaluation – including how to avoid estimate bias.

Historically, the companies have perhaps paid greater attention to ranking their prospects on the basis of criteria other than the absolutely unbiased volumes and the probabilities of success. Exploration on the NCS has nevertheless been and remains profitable. However, ensuring that assessments represent unbiased estimates will be increasingly important as the NCS becomes more mature and discoveries get smaller, in order to avoid decisions to drill in unprofitable prospects.

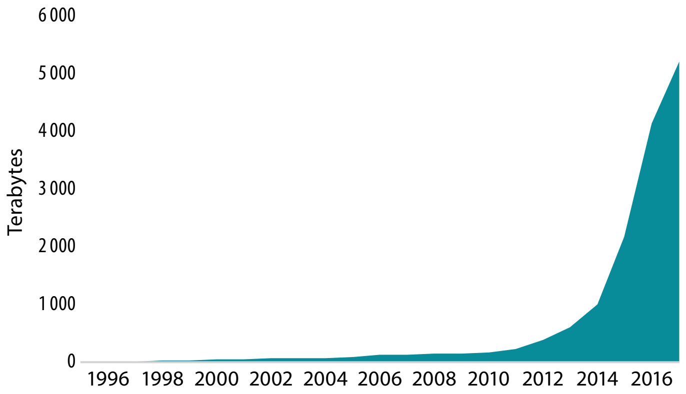


Figure 6.10 *Development of data quantities held in Diskos.*

VISUALISATION, BIG DATA AND MACHINE LEARNING

The earliest seismic interpretation and work stations became available in the mid-1980s. They were developed by research institutions or as proprietary software in big oil companies. From the mid-1990s, computer technology and work stations became better tailored to interpreting large quantities of 3D seismic data. Desktop 3D visualisation of seismic, geological and well-related data became possible from the 1990s, but was first effective after 2000. Since then, functionality has steadily improved.

Visualisation of sub-surface data via virtual reality (VR) systems is making continuous progress – so that geological field trips, for example, can now be conducted in this way. Cloud-based solutions accessible from anywhere in the world will eventually become more important. Sub-surface data from various disciplines can now often be integrated on a common platform.

Big Data, machine learning and artificial intelligence (AI) became part of the exploration industry's vocabulary around 2012. Sub-surface data from seismic surveys and wells contain huge quantities of information, and Big Data analyses could conceivably extract even more information from this. The industry is now trying to understand how that could affect exploration. Many companies have launched major digitalisation projects. In addition, a number of measures have been initiated by such bodies as the NPD, the UK's OGA and the Oil and Gas Technology Centre (OGTC) in Aberdeen. The aim is to understand how Big Data and machine learning can contribute to better and more efficient exploration (fact box 6.2).

Seismic and well information from the NCS is readily available through Norway's Diskos data repository, and much of this material has been made publicly available. The quantity of data in Diskos has grown exponentially since 2010 (figure 6.10). A number of discoveries have been made by re-evaluating available historical data with new techniques and technologies, and by collating them in new ways. Big Data analyses may provide fresh insights here.

Much of the data are difficult to access for analysis today because they are stored in varying formats on different media (such as scanned paper documents). Efforts are now being made in Diskos to improve the organisation of data, so they can become easier to use in such analyses.

FACT BOX 6.2: *Cross-border machine learning project*

Great quantities of well data have been collected for more than 50 years in the North Sea, and this material contains information which could lead to new discoveries. The drawback is that the data are in different formats, vary in quality and can be time-consuming to process for use in analyses. Aberdeen's OGTC is convinced that advanced algorithms, such as machine learning, can help to reduce this challenge. Together with Britain's OGA and the NPD, it has therefore launched a project to seek analysis methods which can quickly and accurately deliver assessments of structured and unstructured well data. The aim is to use this information to identify and classify intervals which could indicate the presence of previously undiscovered or unnoticed petroleum deposits. This project has been established as part of the OGTC's open innovation programme. It is directed at commercial organisations, academic institutions, innovators and entrepreneurs inside and outside the oil and gas industry who might have ideas on how to overcome these challenges. Large quantities of well data from the northern North Sea will be made available by the NPD, the OGA and the OGTC to those presenting the best proposals. The project will be implemented during 2018.

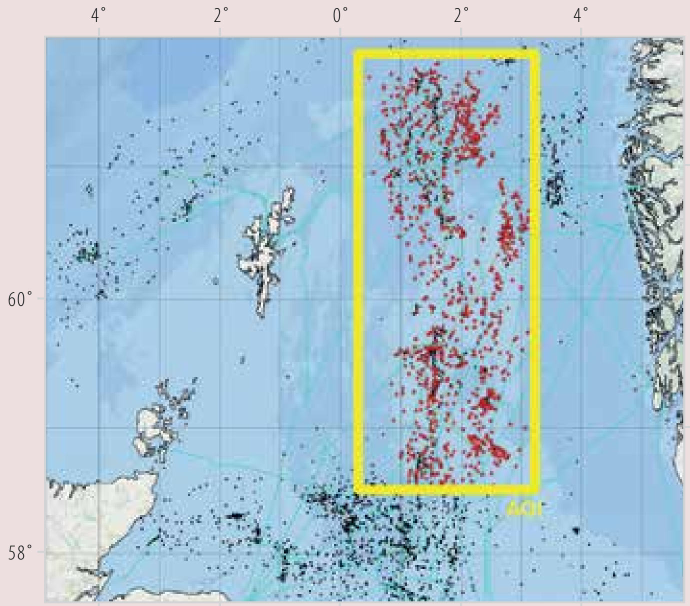
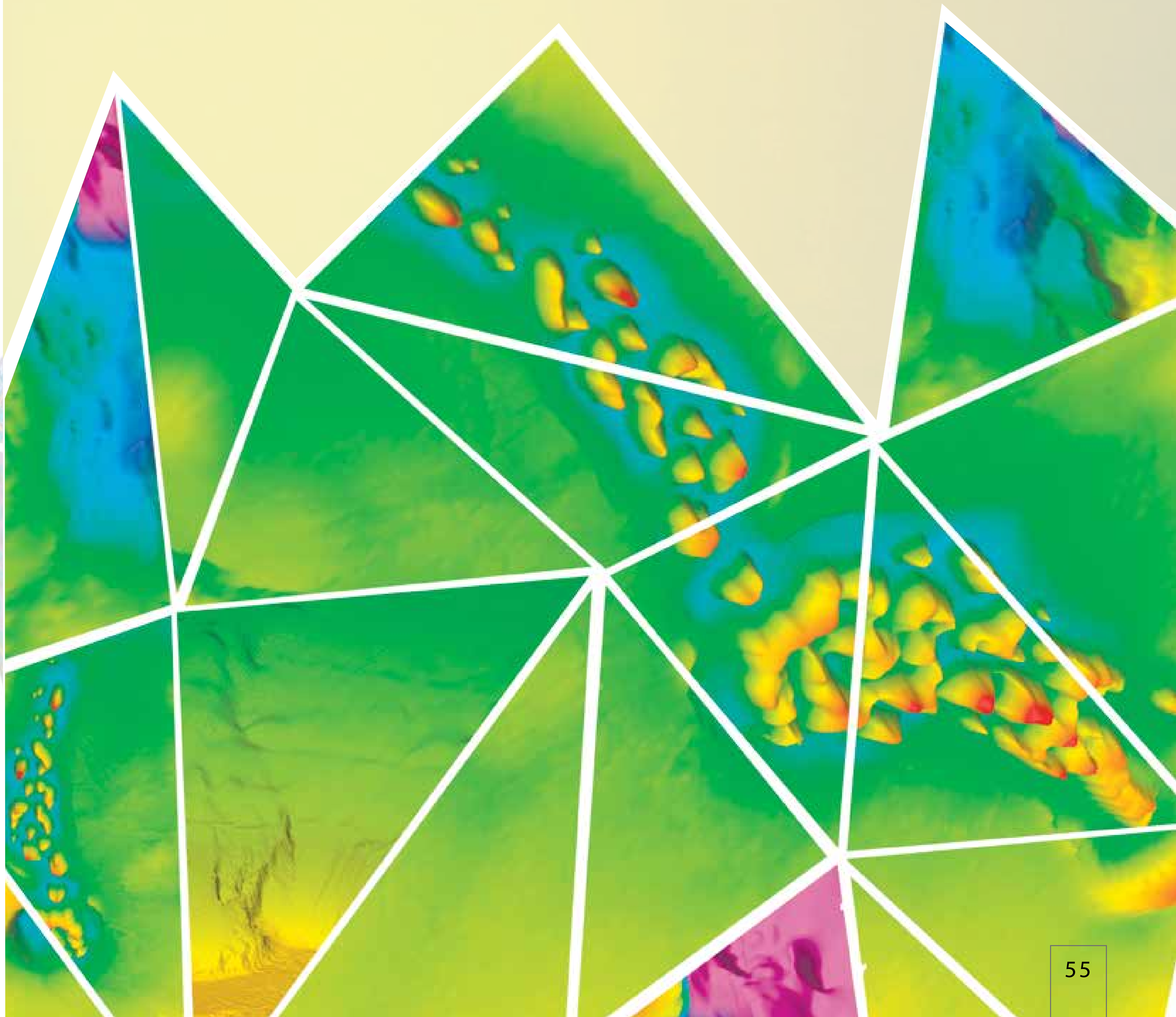


Figure 6.11 *Area covered by the machine learning project (in yellow).*

CHAPTER 7 EXPLORATION LOOK-BACK ANALYSES

Exploration is a learning process.



CHAPTER 7
EXPLORATION LOOK-BACK ANALYSES

The oil industry is known to overestimate the volume in prospects and understate the probability of success. This has been confirmed by the NPD's analyses. The sector has long been working to achieve more accurate estimates. Miscalculations can undermine exploration decisions, and thereby reduce value creation for society. To an even greater extent than before, the industry should collaborate on methods and share experience.

A good factual and knowledge base is a prerequisite if the government is to play a decisive role in resource management on the Norwegian continental shelf (NCS). Given its unique databases, the NPD considers that part of its task involves preparing integrated exploration look-back analyses which can help enhance the efficiency of these activities. Experience from the NCS so far is that lessons from history can contribute to better assessments and estimates, and thereby to improved decisions. A good grasp of the factors which govern company decisions forms part of this knowledge base.

In its 1997 resource report, the NPD presented an analysis which compared company assessments of discovery size and the probability of success for mapped prospects with post-drilling discovery sizes and success rates. Not unexpectedly, this analysis found that the industry overestimated resource expectations and understated the probability of success. These results were in line with studies based on data from beyond the NCS.

Understating the probability of success and overestimating discovery size mean that exploration portfolios at the companies deliver below expectations. That could result in incorrect assessments and exploration decisions, leading to lower-than-desirable value creation for society.

A number of factors can cause errors in such estimates. Called biases in the literature and usually divided between cognitive or motivational,[13] these are well-known in the sector (see chapter 6).

The industry has long worked purposefully to avoid biases in its decision basis, but a number of analyses show that an improvement potential still exists. That finding is underlined by the NPD analyses presented in this chapter.

ESTIMATING DISCOVERY SIZE

COMPARING PRE-AWARD PROGNOSES WITH POST-DRILLING RESULTS

When oil companies apply for new licence awards, their application must document the resource potential in the blocks sought and provide resource estimates for mapped prospects.

Results for eighth to 14th rounds

A study comparing expected values from companies for mapped prospects in the eighth to 14th licensing rounds with discovery size was presented in the NPD's 1997 resource report. This analysis showed that resource expectations were overstated by an average factor of 2.2 (figure 7.1).

Prospect estimates are usually given as a distribution. Even when this was taken into account, discovery size fell within the specified range in only two of 10 cases.

Results 16th-22nd rounds and APA 2003-2011

The industry has long worked on processes which can help correct overestimates. Against that background, the NPD conducted an analysis of discoveries in acreage licensed through the awards in predefined areas (APA) from 2003 to 2011, and through the 16th-22nd numbered rounds (figure 7.2). This analysis was presented by the NPD at the NCS Exploration 2016 – Recent Discoveries conference in May 2016. Comparing the expected value given by the companies for mapped prospects with post-drilling estimates, it again showed that discovery size was overestimated.

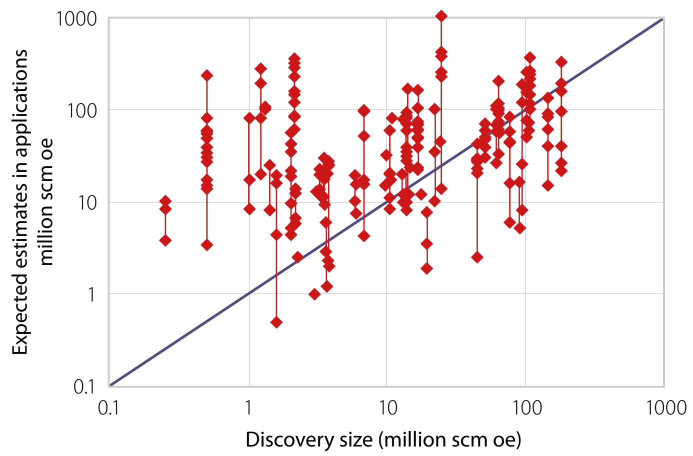


Figure 7.1 *Expected values from companies before award compared with (expected) discovery size (eighth-14th rounds). Vertical red lines link differences in estimates from various companies for the same discovery. Some finds have an estimate from only one company. Source: NPD resource report 1997.*

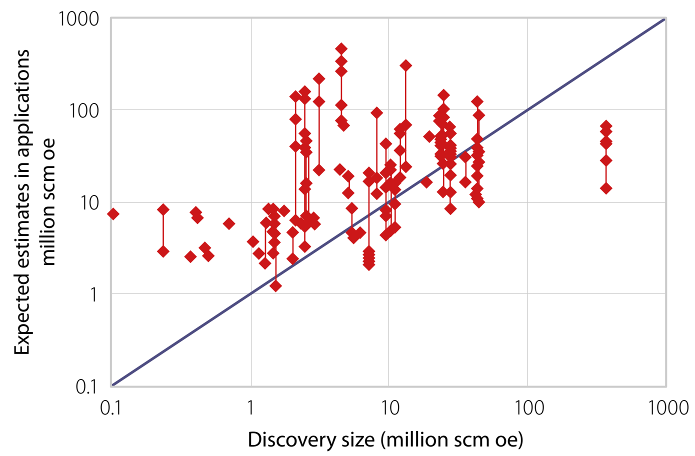


Figure 7.2 *Expected values from companies before award compared with (expected) discovery size (APA rounds 2003-11 and 16th-22nd numbered rounds). Vertical red lines link differences in estimates from various companies for the same discovery. Some finds have an estimate from only one company.*

COMPARING PRE-DRILLING PROGNOSES WITH POST-DRILLING RESULTS

Results 1990-97

A shortcoming in the analysis of company resource estimates in licensing-round applications is that these can be influenced by strategic considerations, which add an extra bias. To take account of this possibility, the NPD initiated an industry project in 1997 on Evaluation of Norwegian Wildcat Wells. One aim was to look at resource size before and after drilling.[14]

The analysis showed that the companies overestimated both oil and gas resources before drilling by an average factor of 2.5 (figure 7.3). The overestimate was largest for oil prospects.

Results 1998-2007

With effect from 1998, operators report prognosed resource estimates and results six months after drilling a wildcat. The estimates provided represent the views of the operators at that time. Figures reported show a distribution with a high estimate (P10), expected value (mean) and low estimate (P90).

The NPD conducted a study in 2008 of pre- and post-drilling results for reported prospects drilled in 1998-2007. A majority of these prospects were based on three-dimensional (3D) seismic data.

The analysis was presented at the 33rd International Geological Congress (33IGC) in Oslo during August 2008 *(Prognoses and results of wildcat wells drilled between 1998 and 2007 on the Norwegian continental shelf)*, and subsequently in the 2011 resource report.

Once again, the companies turned out to overstate their resource estimates by a factor of 2.5.

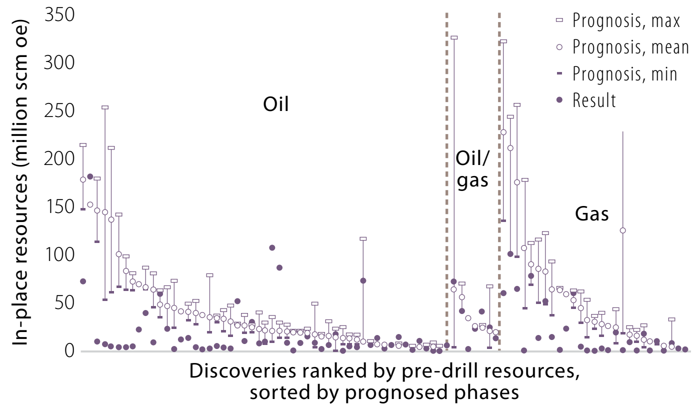


Figure 7.3 *Pre-drilling resource estimates from the companies compared with actual discovery size (195 wildcats drilled in 1990-97). Source: Ofstad, Kullerud and Helliksen (2000).[15]*

[13] See, for example, Tversky, A and Kahneman, D (1981): "The framing of decisions and the psychology of choice", *Science*, vol 211, pp 453-458; Rose, Peter R (2001): "Risk Analysis and Management of Petroleum Exploration Ventures", AAPG, *Methods in Exploration* series, no 12; Milkov, A V (2015): "Risk tables for less biased and more consistent estimation of probability of geological success (PoS) for segments with conventional oil and gas prospective resources", *Earth-Science Reviews*, vol 150, pp 453-476.

[14] Ofstad, K, Kittilsen, J E and Alexander-Marrack, P (2000): *Improving the Exploration Process by Learning from the Past*, Norwegian Petroleum Society, special publication no 9.

[15] Ofstad, K, Kullerud, L and Helliksen, D (2000): *Evaluation of Norwegian Wildcat Wells* (Article 1), in Ofstad et al (2000).

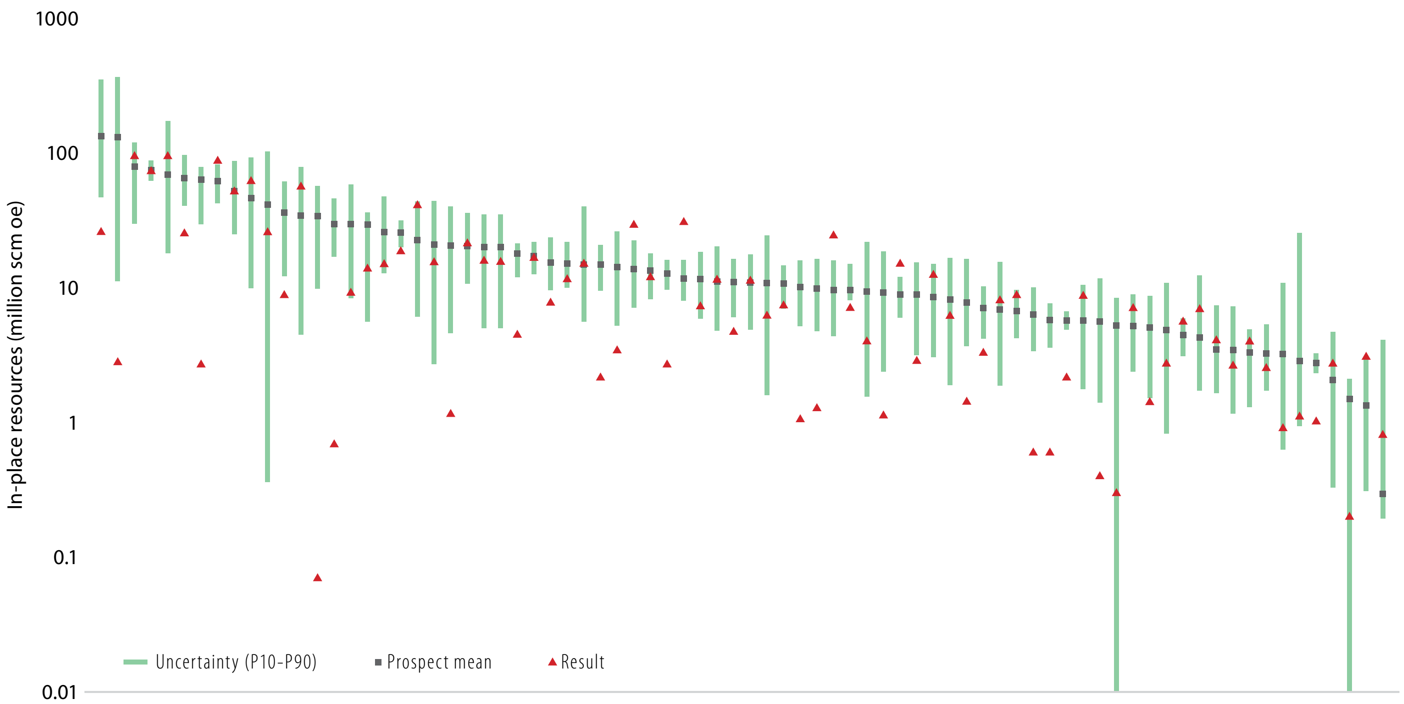


Figure 7.4 *Company pre-drilling resource estimates for oil in place, compared with post-drilling discovery size. The green area shows the P10-P90 range. The squares are the expected discovery size pre-drilling, while the triangles represent the estimated discovery size post-drilling.*

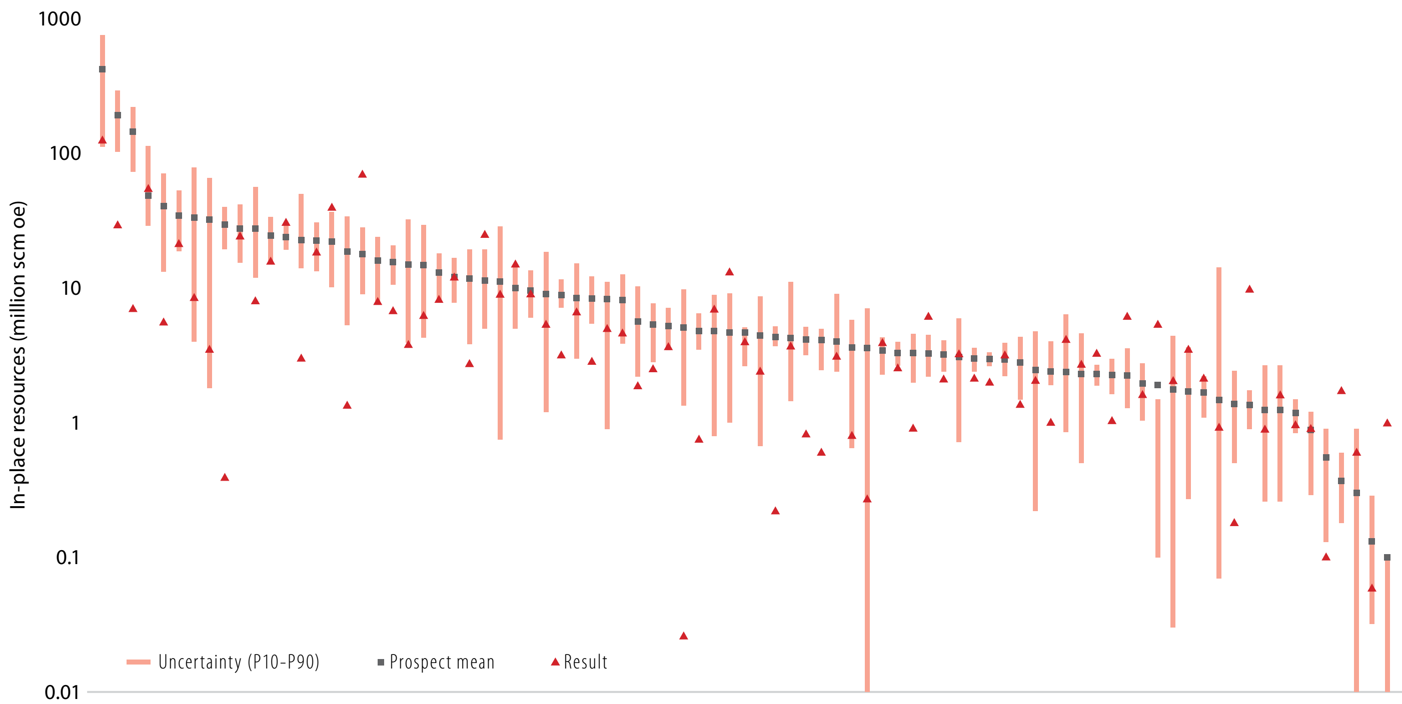


Figure 7.5 *Company pre-drilling estimates for gas, compared with post-drilling discovery size. The red area shows the P10-P90 range. The squares are the expected discovery size pre-drilling, while the triangles represent the estimated discovery size post-drilling.*

Results 2007-16

The NPD carried out a new analysis of pre- and post-drilling results in 2016-17, based on data reported for 2007-16. This work was presented by the NPD to a Force seminar – the Frontier Exploration Workshop – in Stavanger during June 2017.

Results from the study are illustrated in figures 7.4 and 7.5, They show oil volume in place for oil discoveries compared with prognoses (figure 7.4) and gas volume for gas discoveries compared with prognoses (figure 7.5).

Drilling targets with oil as the main phase are entered as oil discoveries, and correspondingly for gas. The associated phase is not included. It is also important to note that the study does not address wells but drilling targets. Each column represents a target which yielded a discovery. Earlier NPD studies were based on resource estimates per well. Since a well may have several targets, this study cannot be directly compared with the earlier analyses.

Discoveries with insufficient reporting or which were described as a "surprise find", and thereby lacked a prognosis, are not included in the study.

The analysis shows that about 58 per cent of oil discoveries fell within the uncertainty range in the prognosed estimate. About six per cent were above and 36 per cent below this range. The companies overestimated resource expectations by an average factor of 1.4.

Where gas is concerned, roughly 47 per cent of finds were within, 16 per cent above and 37 per cent below the uncertainty range. The companies overestimated resource expectations by an average factor of 2.1.

As with earlier studies, the results indicate a clear tendency to overestimate in prognoses.

ANALYSIS OF DRY WILDCATS

The NPD's analyses reveal a tendency to overestimate discovery size and underestimate the probability of success. These results are in line with industry analyses based on company data (Milkov, 2017[16]).

Dry-well analysis can help to improve estimates by companies. Most of them base such studies on their own data. The NPD also regularly carries out analyses of this kind based on reported company information. Its studies cover all wells on the NCS, and provide useful knowledge which could help to boost exploration success. The NPD's latest dry-well analysis was conducted in 2017.

Covering wells drilled in 2007-16, this study was presented by the NPD for the first time at the Exploration Revived 2017 conference.

DATABASE FOR THE ANALYSIS

Pursuant to section 24 of the resource regulations, operators must specify prognoses for and results of wildcats when submitting their final report six months after such wells have been drilled. Reporting uses a standard form developed by the oil companies and the NPD in the 1997 project on Norwegian wildcats mentioned above.

Limited specification of the reported trap type for many of the targets meant this analysis could only distinguish between structural and stratigraphic types. Such factors as total success rate and the most frequently tested stratigraphic reservoir levels were also investigated.

The database varies between the sea areas because of differences in the number of wells drilled. One well can have several targets, and a target can be dry for more than one reason. The North Sea accounts for around 200 targets in the database, the Norwegian Sea about 100 and the Barents Sea roughly 70 (figure 7.6).

[16] Milkov, A V (2017): "Integrate instead of ignoring: Base rate neglect as a common fallacy of petroleum explorers", *AAPG Bulletin* 101 (12): 1905-1916.

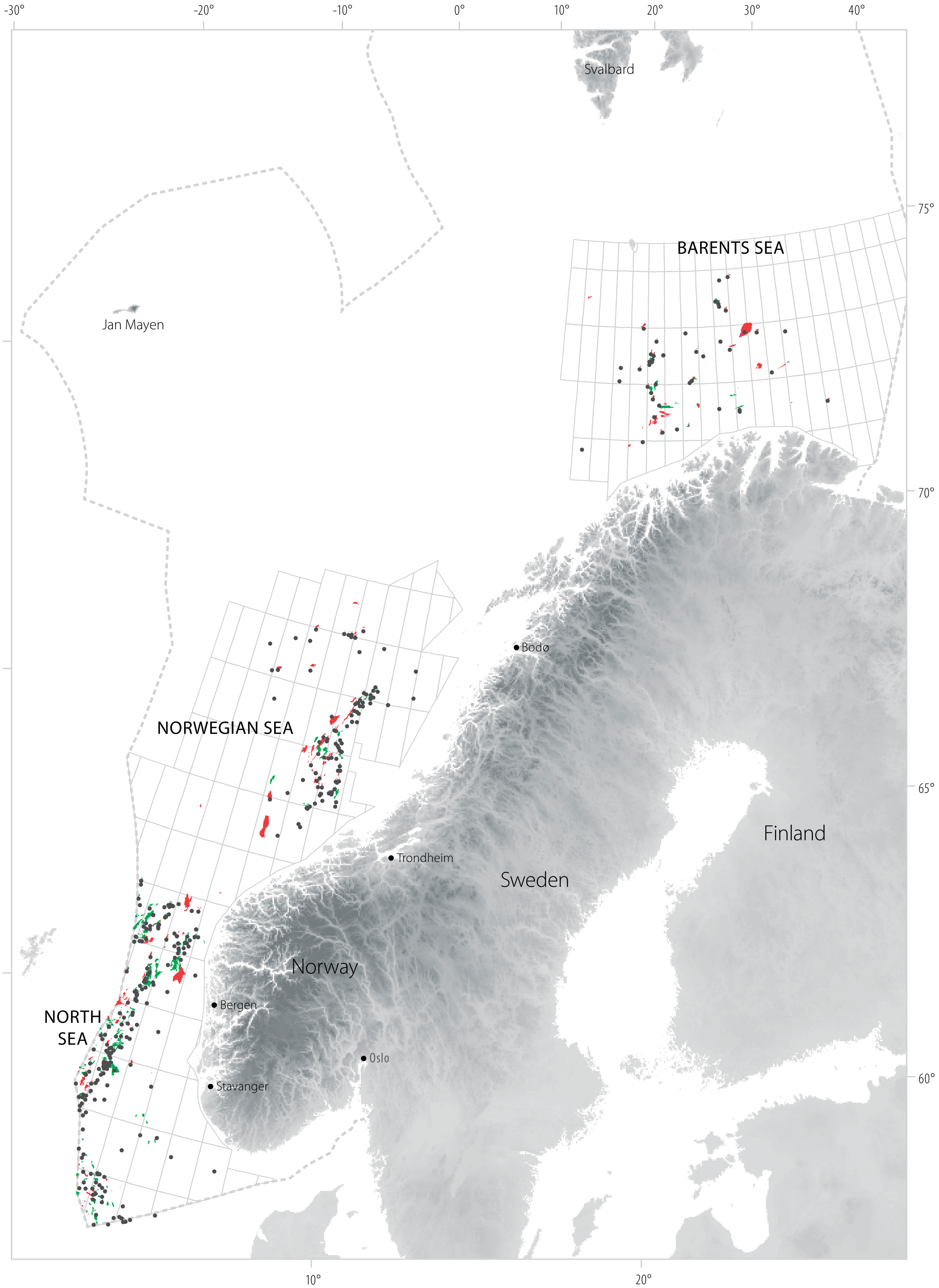


Figure 7.6 *Wells from 2007-16 included in the analysis.*

TRAP TYPE

The study reveals big variations between the various areas with regard to the frequency of testing the different trap types – structural or stratigraphic (figure 7.7). It shows that most targets lay in structural traps – 65 per cent in the North Sea and 82 per cent in the Norwegian Sea. The difference between how often the two trap types were tested was smaller in the Barents Sea. Fifty-six per cent of targets there tested structural types.

STRATIGRAPHIC LEVELS TESTED

The analysis also reveals clear geographical differences between the stratigraphic levels explored, which reflects the unique geological histories of each sea area.

North Sea results (figure 7.8) show that Late Triassic to Middle Jurassic reservoirs were the most frequently tested (44 per cent of targets). Late Jurassic reservoirs were tested in one of four targets (25 per cent), while both Cretaceous and Sub Triassic were tested relatively infrequently (three per cent).

In the **Norwegian Sea**, 60 per cent of targets were in Late Triassic to Middle Jurassic reservoirs (figure 7.8), followed by Late Cretaceous (23 per cent) and Late Jurassic (nine per cent). Only eight per cent lay in Early Cretaceous and Palaeocene reservoir rocks.

The picture in the **Barents Sea** is very different (figure 7.8). Triassic reservoirs were tested in almost every other target (45 per cent), followed by 33 per cent in Jurassic rocks.

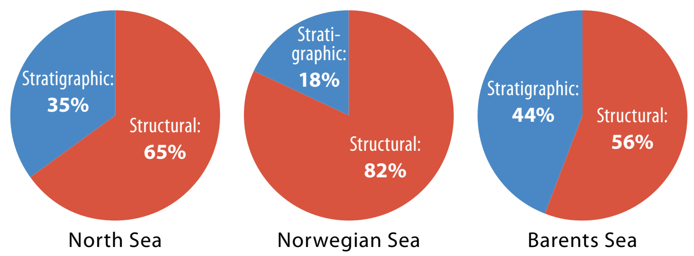


Figure 7.7 *Relationship between exploration targets in structural as against stratigraphic traps in the various areas.*

REASONS FOR DRY TARGETS

The main reasons for dry wells relate to one or more of the following factors:

- reservoir absence
- reservoir quality
- absence of sufficient volume/mature source rock
- lack of oil/gas migration into prospect/target
- absence of effective trap.

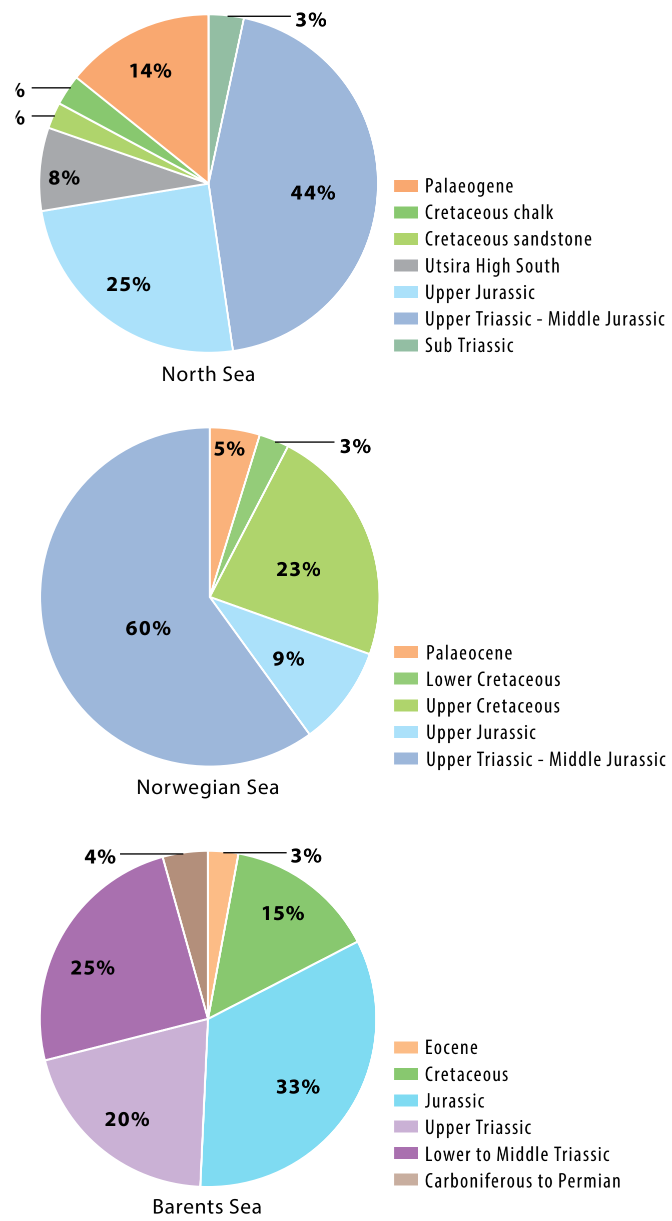


Figure 7.8 *Proportion of stratigraphic levels explored in the North, Norwegian and Barents Seas during 2007-16.*

A limited level of detailing in the reported data meant that the following four main factors were assessed, but a dry target often results from the combination of several of these:

- reservoir absence
- reservoir quality
- source and migration
- trap.

In the **North Sea**, the NPD's analysis shows that the lack of source and/or migration is the main reason why 46 per cent of targets explored were dry (figure 7.9). In most of these cases, the main reason given is failure of migration from source to target. Failed traps are cited as the principle cause in 28 per cent of cases, with reservoir absence accounting for 16 per cent and inadequate reservoir quality for 10 per cent.

Where the **Norwegian Sea** is concerned, 38 per cent of dry targets are primarily attributed to failed traps, 35 per cent to source and migration, and 12 and 15 per cent to reservoir absence and poor quality respectively (figure 7.9).

In the **Barents Sea**, failed traps are the commonest reason given for dry targets, followed by reservoir absence for 27 per cent and source/migration for 20 per cent. Inadequate reservoir quality is cited in 12 per cent of cases.

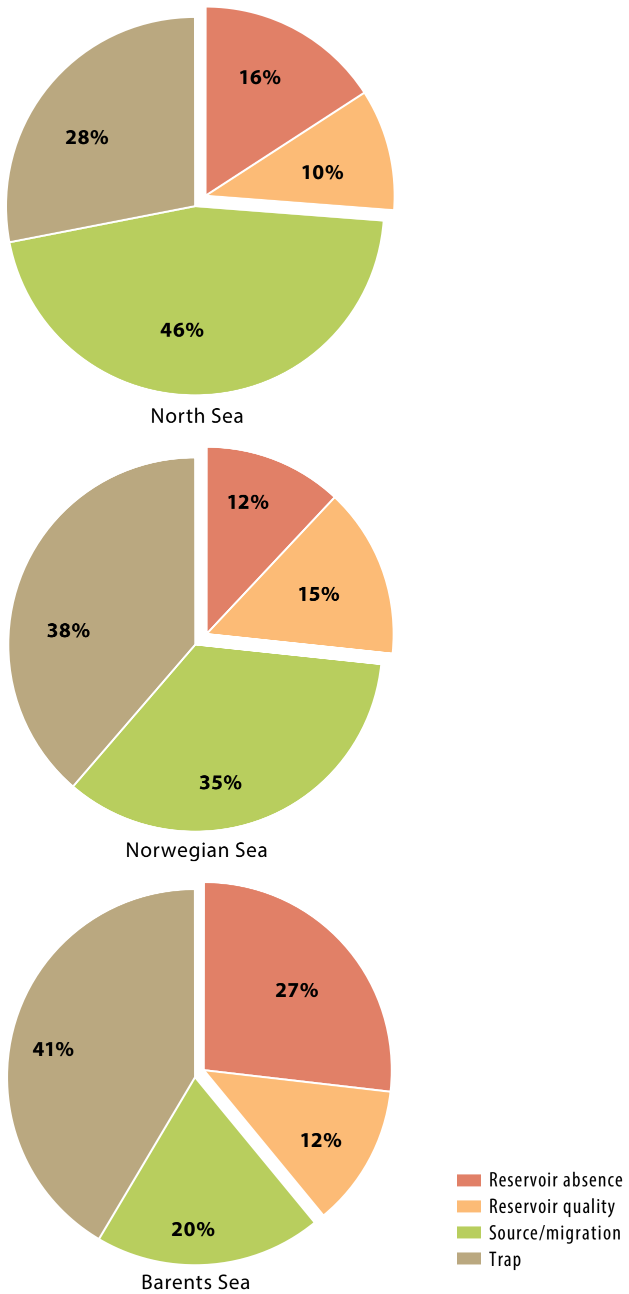
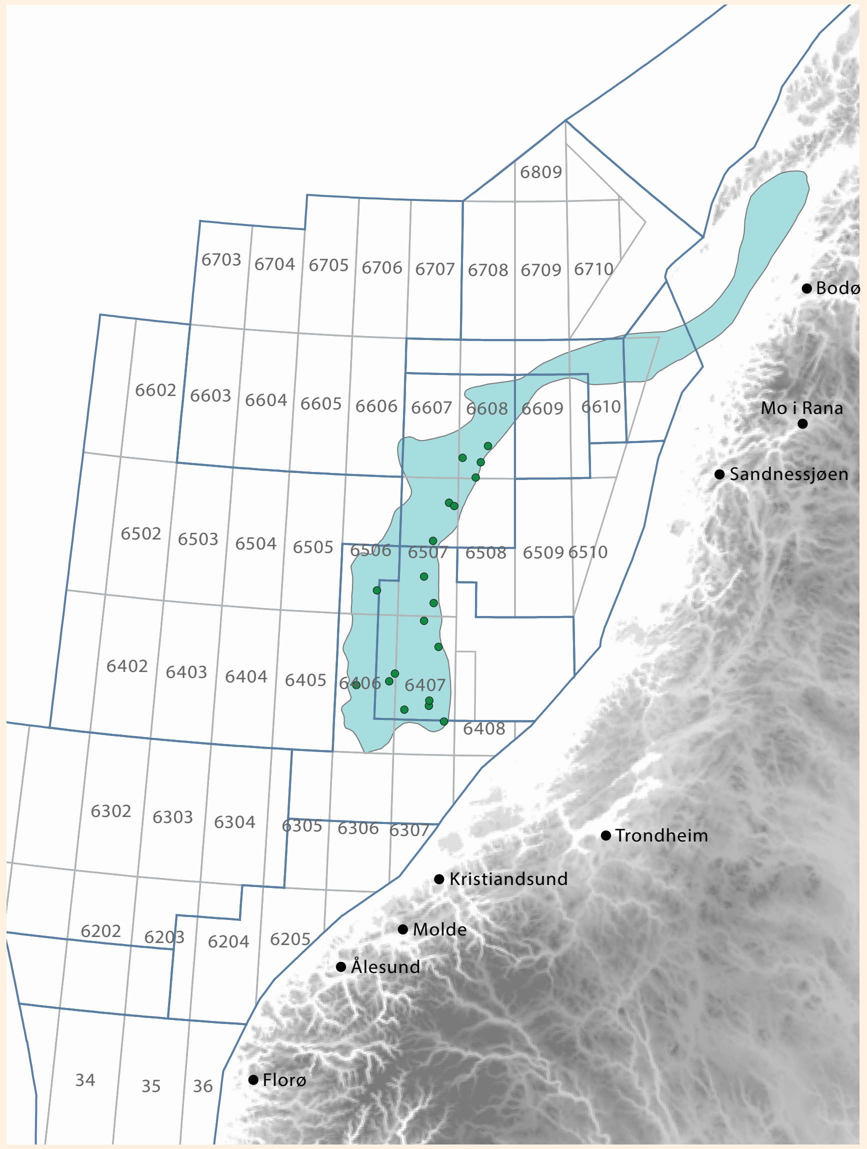


Figure 7.9 *Main reasons reported for dry targets in the North, Norwegian and Barents Seas in percentages.*

FACT BOX 7.2: *Dry targets in selected Norwegian Sea plays*

One of the best-explored plays in the Norwegian Sea from 2007-16 was Late Triassic to Middle Jurassic reservoirs. Examples of fields in this play are Njord, Norne, Åsgard, Alve and Heidrun. The database is nevertheless modest, with only 25 exploration targets.

Figure 7.12 shows that failed traps and source/migration are reported as the two dominant reasons for dry targets. It also shows that reservoirs are generally present and their quality is too poor in only a few cases.



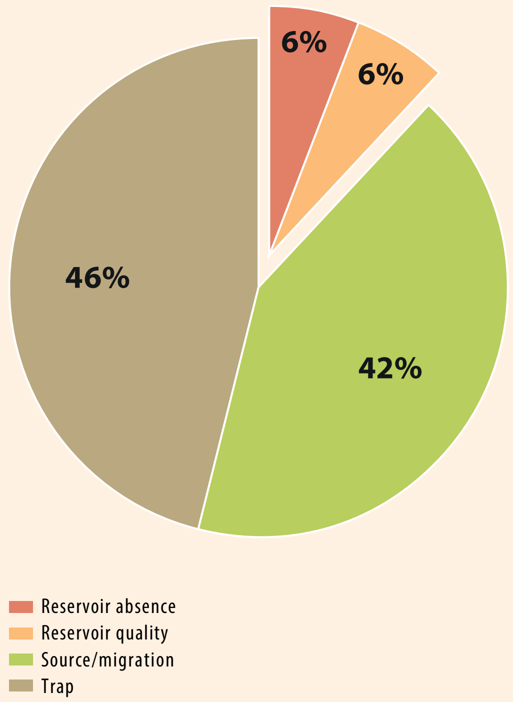


Figure 7.12 *Extent of Upper Triassic to Middle Jurassic plays in the Norwegian Sea.*

***FACT BOX 7.1:** Dry targets in selected North Sea plays*

Where plays with Late Triassic and Middle Jurassic reservoirs are concerned, findings accord with the general trend in the North Sea (figure 7.10). The plays studied have been well explored and include fields such as Statfjord, Sleipner Vest and Yme. Nobody has reported absent reservoirs as a reason for dry targets in any of these plays. The analysis included 18 targets in the northernmost play and 28 in the southern plays.

It is important to emphasise that these analyses are based only on company reports six months after well completion. A dry target usually results from a combination of several factors, and the cause can be difficult to determine with complete certainty.

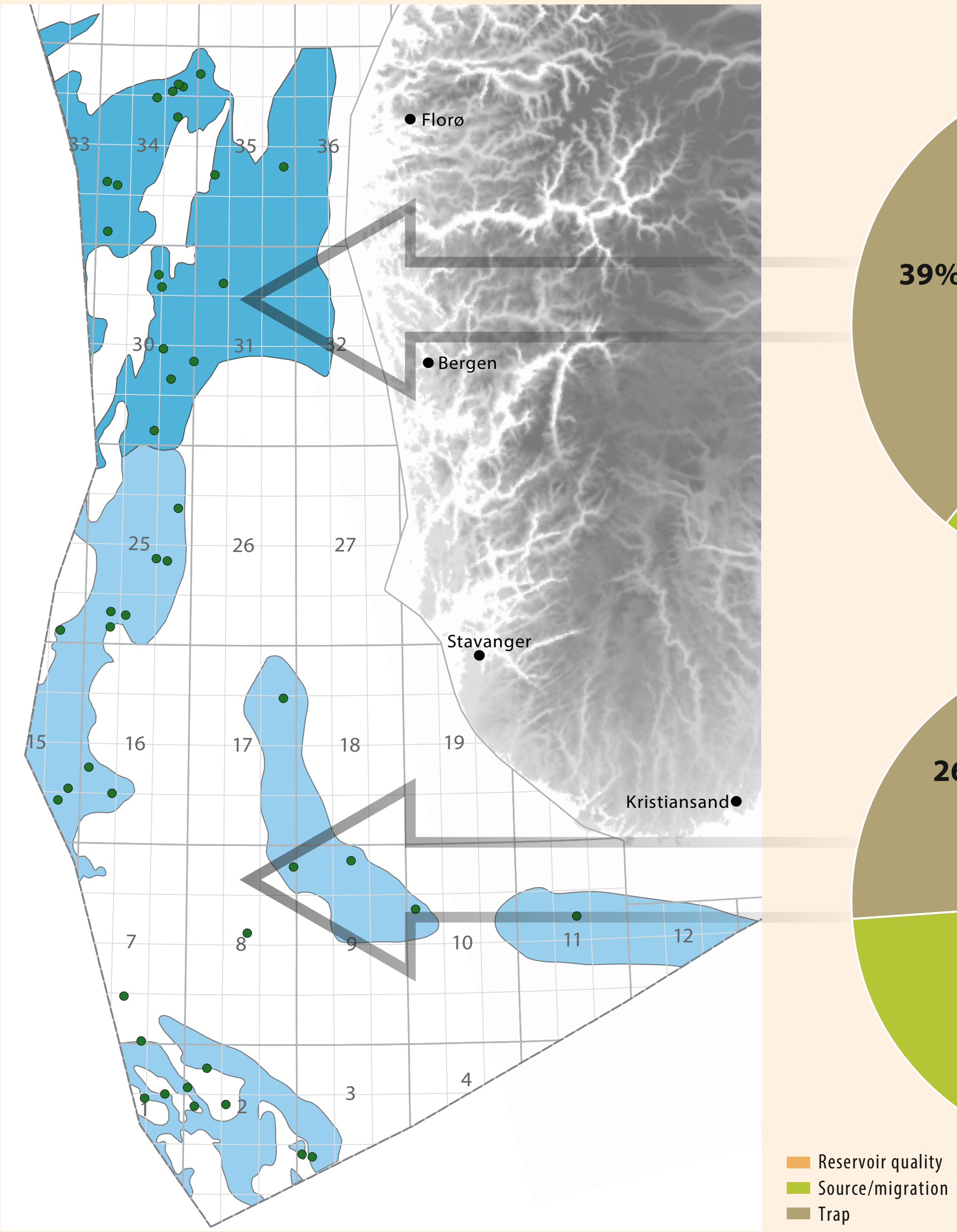


***Figure 7.10.** Extent of Upper Triassic to Middle Jurassic plays in the North Sea.*

With Upper Jurassic plays, which account for about 40 targets in the database, source/migration is again given as the most frequent reason for dry targets (figure 7.11). These plays include such fields as Troll, Statfjord Nord and Ula.

Failed traps are the most frequent (33 per cent) reason given for dry targets in plays with Cambrian-Silurian to Early Cretaceous reservoirs on the Utsira High. Both reservoir absence and poor reservoir quality are reported as the reasons in 25 per cent of cases. However, the database is somewhat restricted and only 11 targets are included in the analysis. This play is limited in extent and includes such fields as Johan Sverdrup and Edvard Grieg.

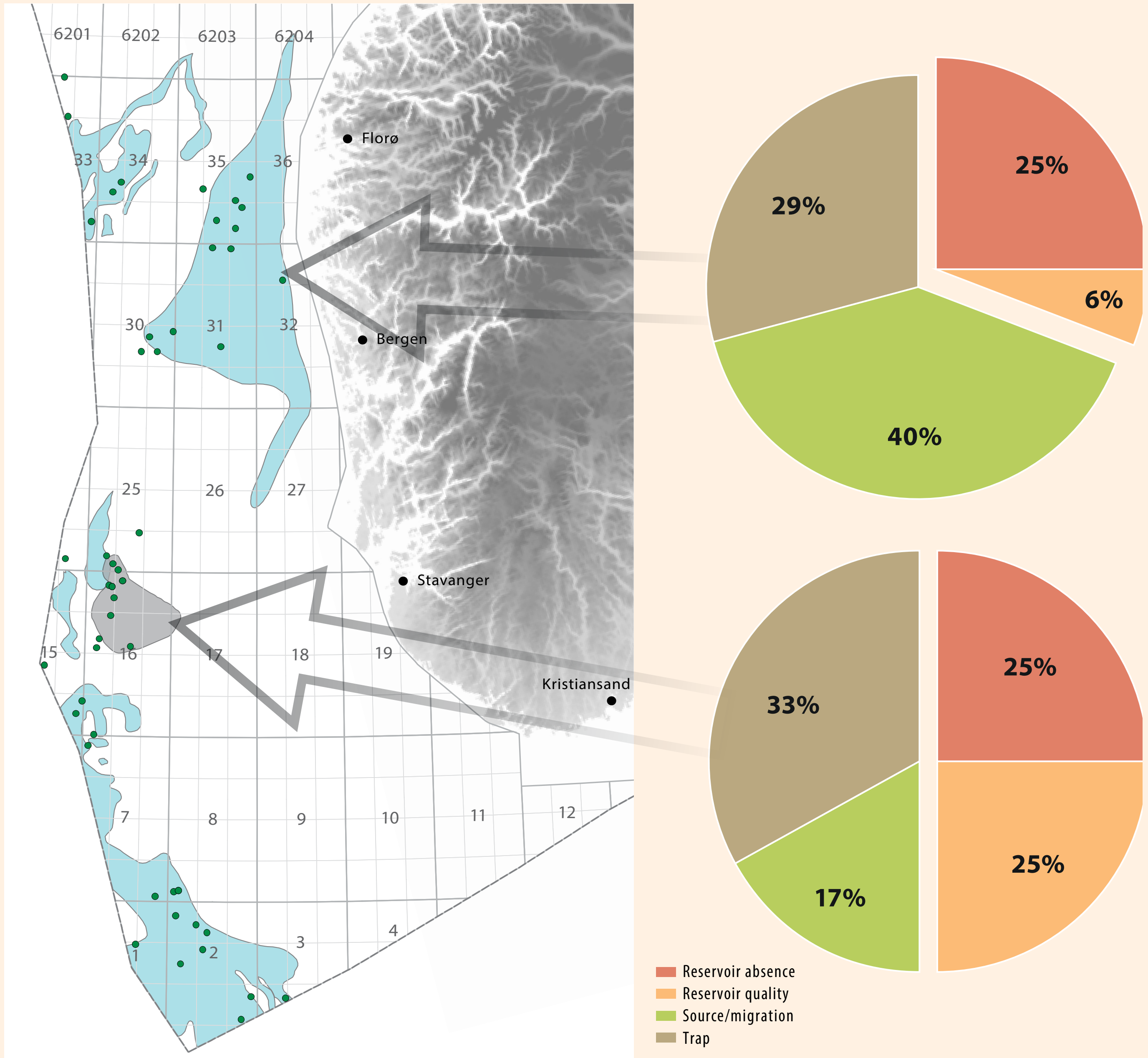
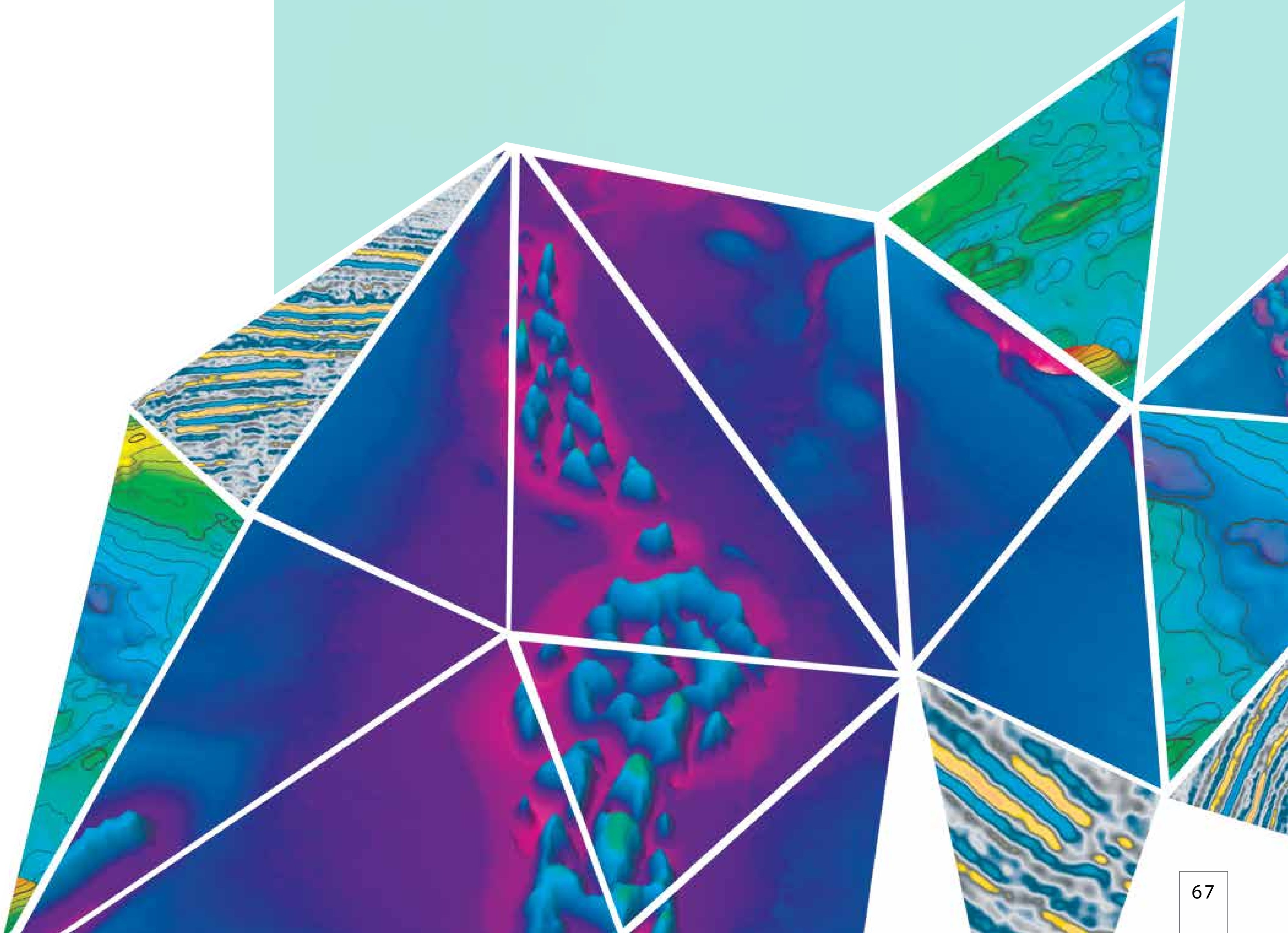


***Figure 7.11.** Extent of Upper Jurassic to Sub Upper Cretaceous plays in the North Sea.*

CHAPTER **8**

RESOURCES FOR THE FUTURE: SEABED MINERALS AND GAS HYDRATES

The Norwegian continental shelf – more than oil and gas.



The increased attention being paid to producing energy with a low carbon footprint is expected to boost demand for gas and renewables. Developments with renewable energy sources and battery technology call for access to substantial quantities of minerals with rare-earth elements (REEs). Mapping has shown that such resources could also be present on Norwegian territory. The NPD is due to launch its own investigations in the summer of 2018 to improve understanding of the resource potential on the Norwegian continental shelf (NCS).

Energy production with a low carbon footprint could mean rising demand for gas and minerals with REEs. Renewable energy output and the associated need for battery storage is expected to grow (fact box 8.1). It has long been known that big deposits of minerals with REEs could exist in the deep oceans.

SEABED MINERALS

On 1 April 2017, the Ministry of Petroleum and Energy (MPE) was given administrative responsibility related to prospecting for and recovering mineral deposits on the NCS. Administrative authority for seabed minerals has been delegated to the NPD. That includes mapping resources, compiling resource accounts and following up the industry's activities, as well as providing technical and economic advice to the MPE. Little exploration for mineral deposits has so far taken place in Norwegian sea areas, and the applicable legislation is not designed for such activity. The MPE is therefore working on a new Act covering mineral recovery from the NCS.

Where the NCS is concerned, seabed minerals are known to exist in the deep parts of the Norwegian Sea (figure 8.3). The University of Bergen (UiB) made the first discoveries of "black smokers" there more than a decade ago (fact box 8.2). Drawing in part on the NPD's large multibeam bathymetric data set from these waters, the UiB identified a number of sulphide deposits (both smokers and mounds) along the volcanic Mohn Ridge between Jan Mayen and Bjørnøya and further north. Samples have since been taken from a number of sulphide deposits and crusts while mapping the Norwegian Sea in a multi-year research partnership between the UiB and the NPD.

In addition to the Norwegian Sea deposits, manganese crusts could be present around the Yermak Plateau in the Arctic Ocean north of Svalbard.

The NPD has carried out chemical analyses of thick manganese crusts on the steep slopes of the Jan Mayen Ridge and the Vøring Spur. These have revealed that manganese crusts in the Norwegian Sea fall into two groups in terms of their lanthanide content. One has twice the amount found in Pacific and other Atlantic sources, the other has less. Both groups contain substantially more lithium (20-80 times as much) and scandium (four-seven times) than similar crusts in the Pacific and the rest of the Atlantic. These two metals are both expected to be in demand.

A data acquisition expedition focused on sulphides was conducted during 2017 by the NPD in collaboration with the UiB on the Mohn Ridge. Plans for 2018 include a large survey concentrated on massive sulphide deposits from inactive hydrothermal systems and a separate mission focusing on iron-manganese crusts.

FACT BOX 8.1: *Why is demand for minerals and REEs expected to rise?*

Growing demand for renewable energy sources such as sun, wind and water increases the need for a range of minerals. These include those containing elements categorised as REEs by the International Union of Pure and Applied Chemistry (Iupac), which are necessary components in such products as wind turbines, solar panels and electric cars.

Old light bulbs are being replaced by modern and more efficient LED versions, and petrol/diesel engines by electric motors. At the same time, the world wants to remain at an advanced technological level with ever-newer mobile phones, TVs, computers, cameras and other devices dependent on powerful but miniaturised batteries. That calls for large quantities of such materials as lithium, copper, cobalt, manganese, nickel, yttrium, lanthanides, neodymium and cadmium.

Thin low-cost solar panels need tellurium (a byproduct of copper and lead refining), while lithium and cobalt are used in efficient modern batteries. The first of these is primarily extracted today from saline flats (salars) in North and South America.

Cobalt is a byproduct of refining nickel, silver, lead and copper ores, with the Democratic Republic of the Congo as the biggest source. Employed as a catalyst in hydrogen fuel cells, platinum comes almost wholly from South Africa. Neodymium is used in making powerful magnets for electric cars and wind turbines. Today's mobile phones can contain up to 62 different metals, including as many as 10 REEs.

Ores containing the metals in demand are not renewable resources. And, despite steadily growing demand, these materials are recycled in only limited quantities because this involves handling very small quantities in complex entities. Thin layers of metal and metallic alloys must be separated from plastic, glass and other components with the aid of demanding and environment-unfriendly processes.

Alternative sources of REEs must therefore be found if expected future demand is to be met. The table shows an overview of elements representing relevant resources.

Elements relevant as resources	Application	Origin	Main exporters
Platinum	Vehicle emission control devices	Alluvial, nickel-copper and chrome deposits	South Africa
Cadmium	Batteries	Byproduct of refining sulphidic zinc deposits	China, South Korea
Titanium	Alloys (laptops, spacecraft)	Minerals such as ilmenite, brookite and anatase	Australia, Canada, China
Cobalt	Batteries, super-alloys	Massive sulphide deposits	DR Congo
Lithium	Batteries, glass and ceramics	Evaporites, pegmatite and smectite	Australia, Chile
Lanthanum	Enhancing performance of glass and steel	Alkaline rocks and carbonatites	China
Manganese	Aluminium alloys, batteries	Carbonates	India, Australia, China
Neodymium	Permanent magnets	Alkaline rocks and carbonatites	China
Nickel	Alloys, batteries	Weathered ultra-mafic rocks	Indonesia, Philippines
Scandium	Aluminium alloys	Byproduct of REE mineral and metal refining	China, Russia, Ukraine, Kazakhstan
Tellurium	Solar panels	Byproduct of copper and lead refining	Russia, Sweden, Japan
Yttrium	LED, superconductors	Weathered clay	China
Copper	Electric cars and related infrastructure	Chalcopyrites	Chile
Dysprosium	Permanent magnets	Alkaline rocks and carbonatites	China
Europium	Superconductors	Alkaline rocks and carbonatites	China

Table 8.1 *Overview of elements representing relevant resources.*

FACT BOX 8.2: *Three main types of deepsea minerals*

Manganese nodules lie on soft seabeds at great ocean depths, and contain large amounts of manganese and iron with smaller quantities of copper, nickel, cobalt, titanium and platinum. They are not expected to occur on the NCS.

Manganese crusts also consist largely of manganese and iron, plus small quantities of titanium, cobalt, nickel, cerium, zirconium and REEs. They grow as laminated deposits on bare bedrock exposed at the seabed, typically in water depths of 800-2 500 metres. As with manganese modules, elements precipitated from seawater become concentrated in such crusts.

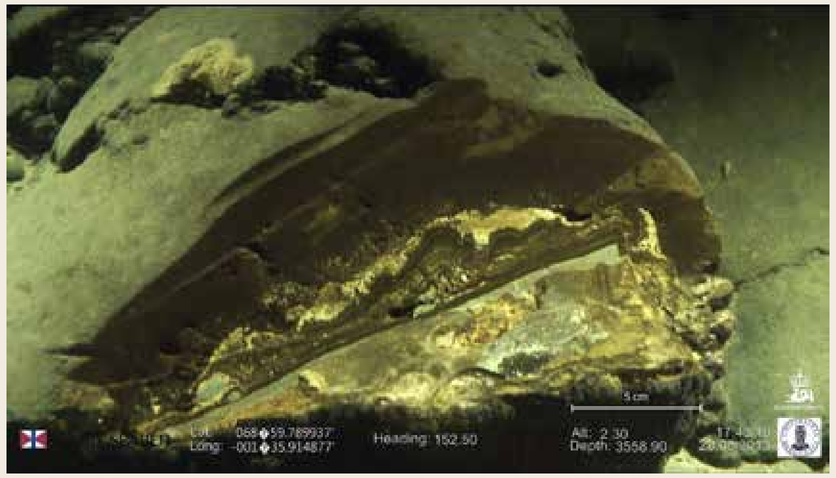


Figure 8.1 *Manganese crust in the Norwegian Sea.*

Sulphides primarily contain lead, zinc, copper, gold and silver, and are linked to hot springs in volcanic spreading ridges beneath the oceans where black smokers form. These vents continue to spew out hot material for several thousand years before dying out and leaving behind sulphide mounds which contain the bulk of the sulphide ore resources (figure 8.2, right).

Figure 8.2 *Active (left) and inactive (right) sulphide deposits in the Norwegian Sea.*

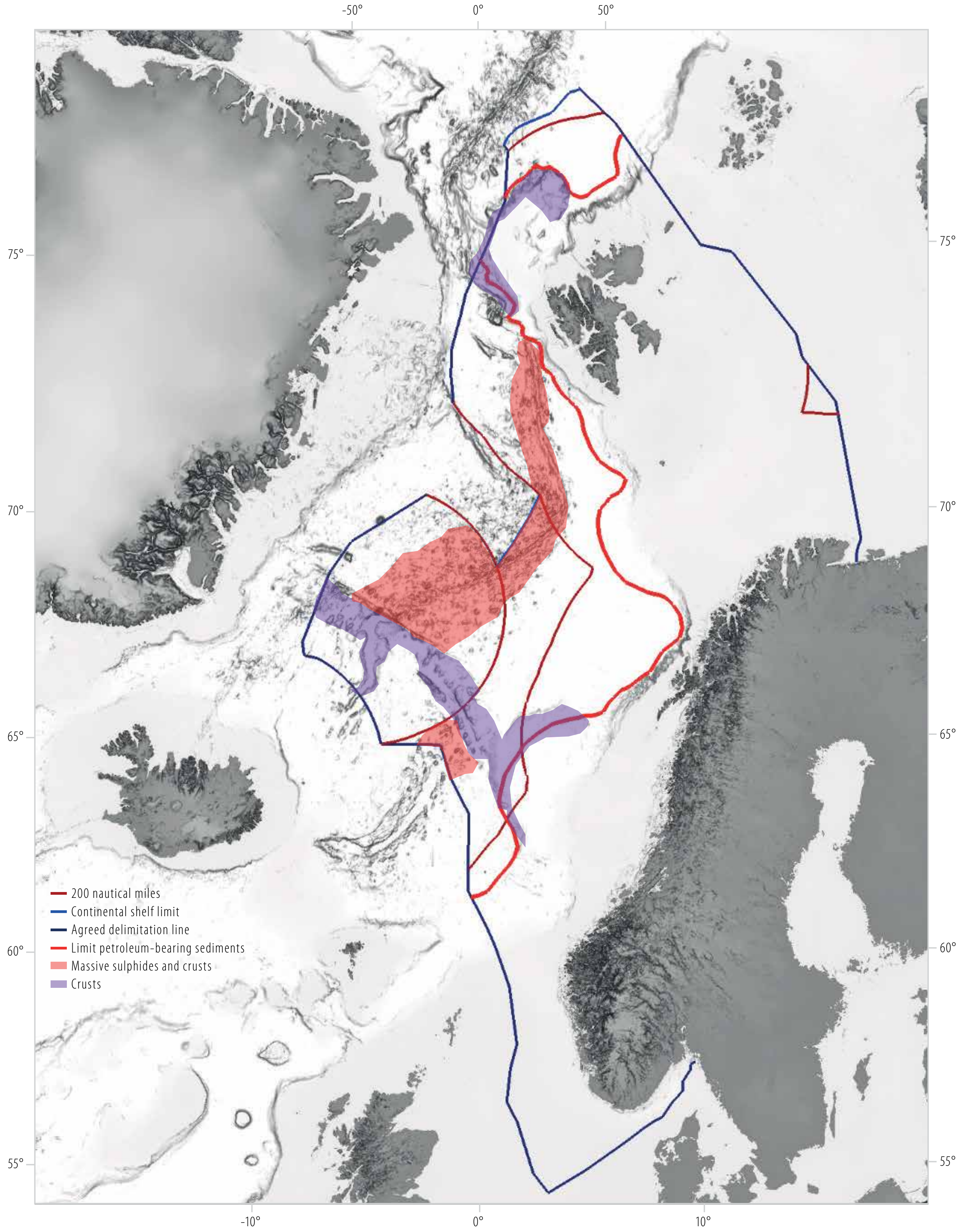


Figure 8.3 *Areas of the NCS with possible deposits of seabed minerals.*

GAS HYDRATES

Natural-gas hydrates could become a future energy source. They are present in large quantities immediately beneath the seabed in some parts of the Norwegian and Barents Seas. Their extent is likely to be greatest in the Barents Sea, where deposits appear to extend over large areas.

FACT BOX 8.3: *What are gas hydrates?*

Natural-gas hydrates are gas in a solid form which primarily comprises methane and water. They have a crystalline structure where the water molecules act as a lattice enclosing the gas (figure 8.4). Gas hydrates are found beneath the permafrost in Arctic regions and under the seabed in ocean depths with high pressure and low temperature (typically more than 60 bar and below 10°C). They represent a highly condensed form of natural gas bound in water. A cubic metre of hydrate corresponds to 160 cubic metres of natural gas at atmospheric conditions. This substance forms in a region known as the gas hydrate stability zone (GHSZ). In a maritime environment, hydrates lie beneath the seabed and the thickness of the GHSZ is defined by the ambient water temperature, sea level, geothermal gradient, gas composition and salt content of sedimentary pore water (Chand et al, 2012).

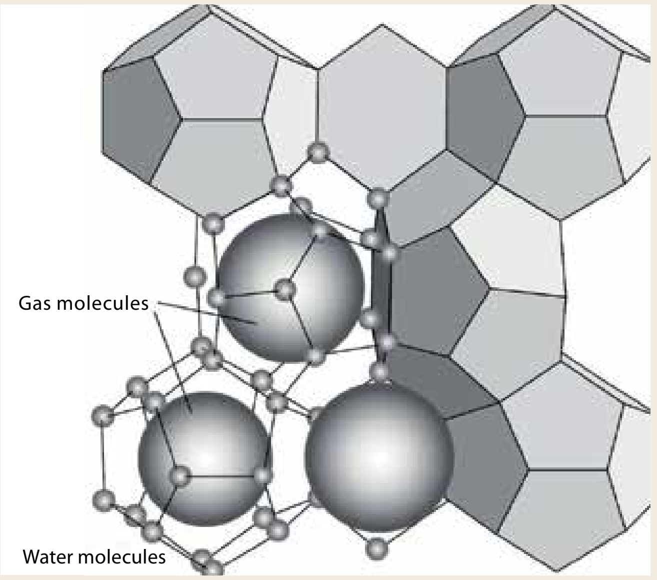


Figure 8.4 *A model showing the molecular structure of gas hydrate. The water molecules form a lattice which encloses the gas molecules. From Maslin et al (2010).*

Water depths on the Barents Sea's continental shelf go down to 500 metres. Seabed temperatures can be 0°C or lower. That means the thickness of the GHSZ may be anything from a few tens of metres to 400 metres, depending on gas composition and geothermal gradient (figure 8.5, based on Chand et al, 2012).[17 18]

Figure 8.5 presents the thickness of the GHSZ. Its thickest extent in the south-western Barents Sea coincides with the deepest part of the continental shelf there. In this area, gas hydrates could act as a cap over hydrocarbons in shallow reservoirs. They have been found on the Vestnes Ridge west of Spitsbergen, and good indications of methane hydrates exist in the Bjørnøya Basin.

The NPD is involved in a number of projects related to research on gas hydrates, in collaboration with the Centre for Arctic Gas Hydrate, Environment and Climate (Cage) at the University of Tromsø – the Arctic University of Norway (UiT). Attention in recent years has concentrated on understanding how gas hydrates affect petroleum systems and pressure.

No commercial method has so far been found for producing gas hydrates, but research into such solutions is being pursued internationally.

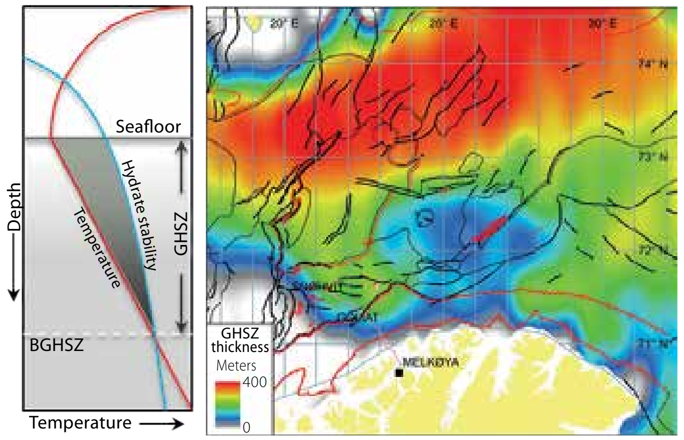
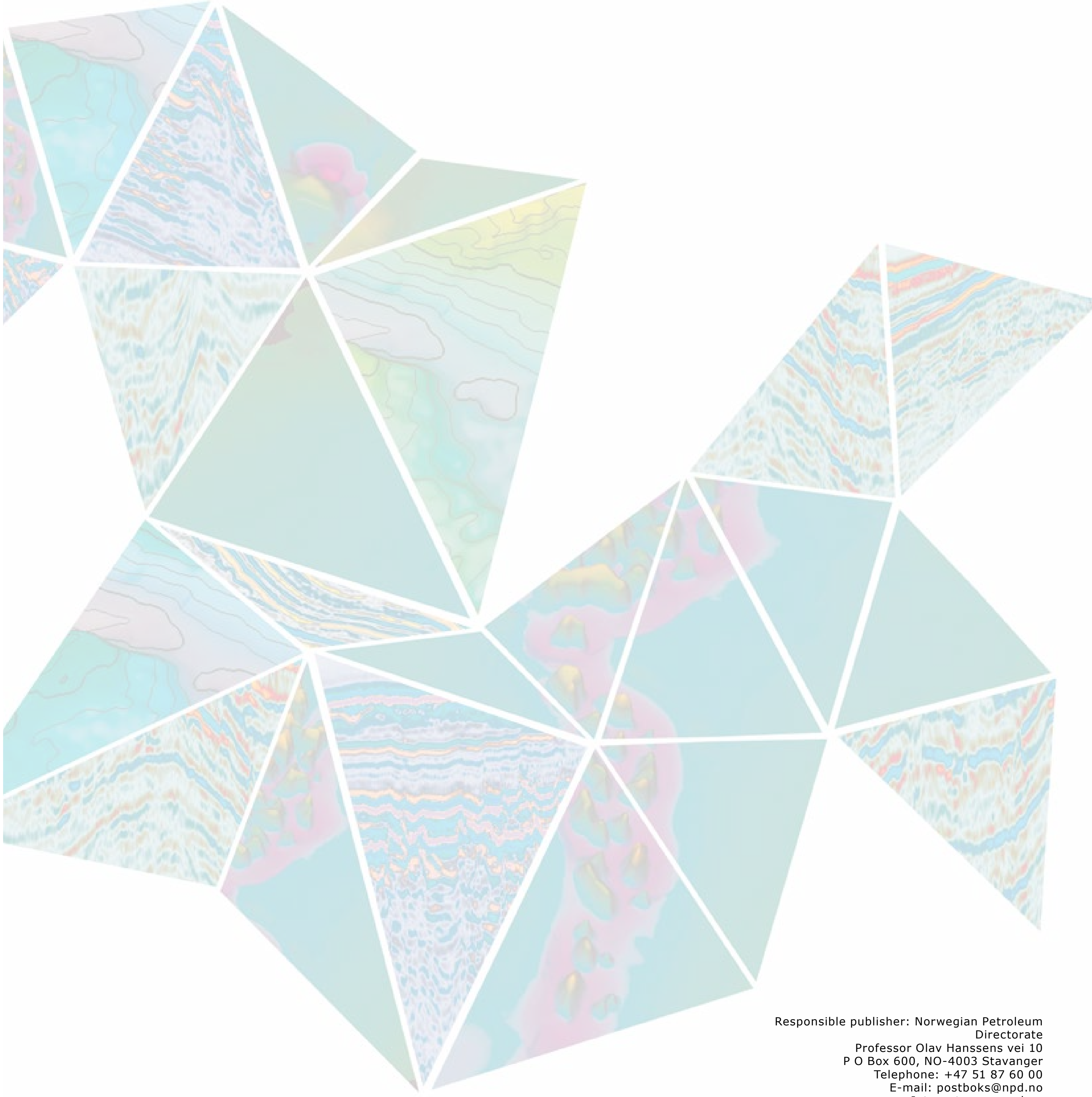


Figure 8.5 *Thickness of the gas hydrate stability zone in the Barents Sea. Based on Chand et al, 2012*

[17] Chand, S, Thorsnes, T, Rise, L, Brunstad, H, Stoddart, D, Bøe, R, Lågstad, P and Svolsbru, T (2012). "Multiple episodes of fluid flow in the SW Barents Sea (Loppa High) evidenced by gas flares, pockmarks and gas hydrate accumulation". *Earth and Planetary Science Letters*, pp 331–332, 305-314.
[18] Maslin, M, Owen, M, Betts, R, Day, S, Dunkley Jones, T and Ridgwell, A (2010). "Gas hydrates: past and future geohazard?" *Philosophical Transactions of the Royal Society A: Mathematical, Physical and Engineering* Sciences 368, pp 2369-2393.



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