NORWEGIAN PETROLEUM DIRECTORATE

The Shelf 2017

11 January 2018

Content list

High activity on the shelf

Never before has so much gas been sold from the Norwegian shelf as was the case in 2017. Oil production was down slightly; nevertheless, overall production rose for the fourth straight year.

The Norwegian Petroleum Directorate's forecasts indicate that the production increase will continue toward 2023 – perhaps even reaching the level of the record year 2004. Back then, oil accounted for most of the production. In 2023, gas will account for about one-half of the production.

"The high production forecasts are good news for everyone who is interested in value creation in Norway," says Director General Bente Nyland.

Exploration activity must increase

At year-end, there were 85 producing fields on the Norwegian shelf, five of which came on stream in 2017. In addition, plans for development and operation (PDOs) were submitted for ten new projects, while nine are currently undergoing development.

"If production is to be maintained at a high level also beyond 2025, more profitable resources must be proven, including in major discoveries. Therefore, the Norwegian Petroleum Directorate believes that exploration activity must be increased from today's level, in both mature and frontier areas" says Nyland.

Last year, 34 exploration wells were completed, three fewer than the previous year. Half of the wells were drilled in the Barents Sea, twelve in the North Sea and five in the Norwegian Sea. Eleven discoveries were made, compared with 18 in 2016. All of the discoveries were relatively minor, but several of them could become profitable developments if they are tied in to fields currently in operation.

Despite the decline in the number of exploration wells in the last few years, the companies exhibited significant interest in new acreage in the most recent licensing rounds. A total of 56 production licences were awarded in APA 2016, and as many as 39 companies applied for acreage in APA 2017, submitting a record number of applications.

Eleven companies submitted applications in the 24th licensing round.

Significant opportunities in the North

In 2017, the Norwegian Petroleum Directorate updated its estimates for undiscovered resources, e.g. based on its own mapping of the unopened areas in the Barents Sea North.

The update reveals that the volume of resources in the Barents Sea is now around 80 per cent higher than in the previous analysis from 2015, while the estimate is unchanged for the North Sea and the Norwegian Sea.

"Nearly two-thirds of the undiscovered resources are located in the Barents Sea. This area will be important in maintaining high production over the longer term," comments Bente Nyland.

Substantial cost cuts
Since 2014, the industry has made significant efforts to cut costs. A wide range of measures have been implemented, both in the planning, execution and operations phases.

Development project costs have been cut by 30 to 50 per cent in the last couple of years while, at the same time, the price of oil has risen. This has meant that the companies see more profitable projects. Operating costs have been reduced by around 30 per cent since 2013/2014.

“The projects now being approved generally have good profitability and can tolerate an oil price as low as 30-40 dollars per barrel,” says Nyland.

After several years of reduced investments, the decline is now levelling off. In 2018, the Norwegian Petroleum Directorate expects investments to be around NOK 122 billion, about the same level as last year. In 2019, investments are expected to rise to just under NOK 140 billion.

1 Increasing oil and gas production for the next five-year period

The Norwegian Petroleum Directorate's production forecast up to 2022 shows an increase from 2020, when Johan Sverdrup has come on stream. Total production of oil and gas in 2022 is estimated to be close to the record-breaking year 2004. Gas will then account for about one-half of the production.

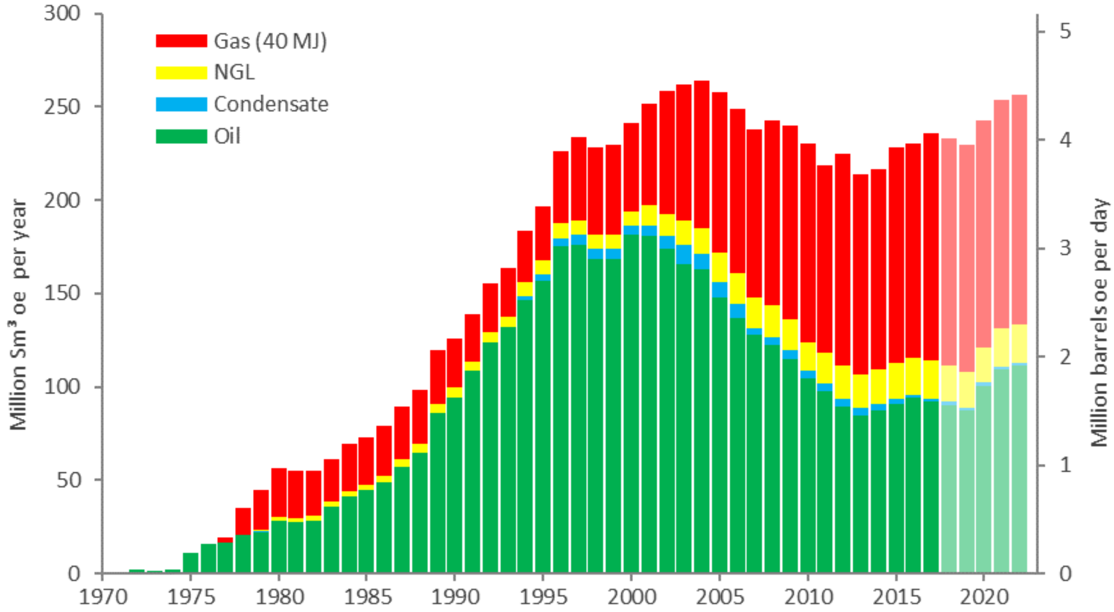


Figure 1-1 Actual and projected sale of petroleum 1971-2022

The total production increased in 2017 for the fourth straight year. Preliminary figures show that 236.4 million standard cubic metres of oil equivalents (Sm³ o.e.) was sold in 2017. This is 6.3 million Sm³ o.e. or 2.7 per cent more than in 2016. Total production of petroleum in 2018 is expected to remain at about the same level as in 2017, with a slight reduction to 233 million Sm³ o.e.

Gas record

In 2017, total sales of gas amounted to 124.2 billion Sm³ (122.0 billion Sm³ 40 megajoules of gas). This is a new Norwegian gas sales record. It is difficult to predict gas sales levels, even in the short term. Sales in 2017 ended 6.6 per cent higher than our estimates at the same time last year. This is due, in part, to consistently high demand for gas from Europe. Several fields in operation have increased the gas production. The forecast for short-term gas sales (Figure 1-2) shows that a stable high level with a minor increase over the next five years is expected.

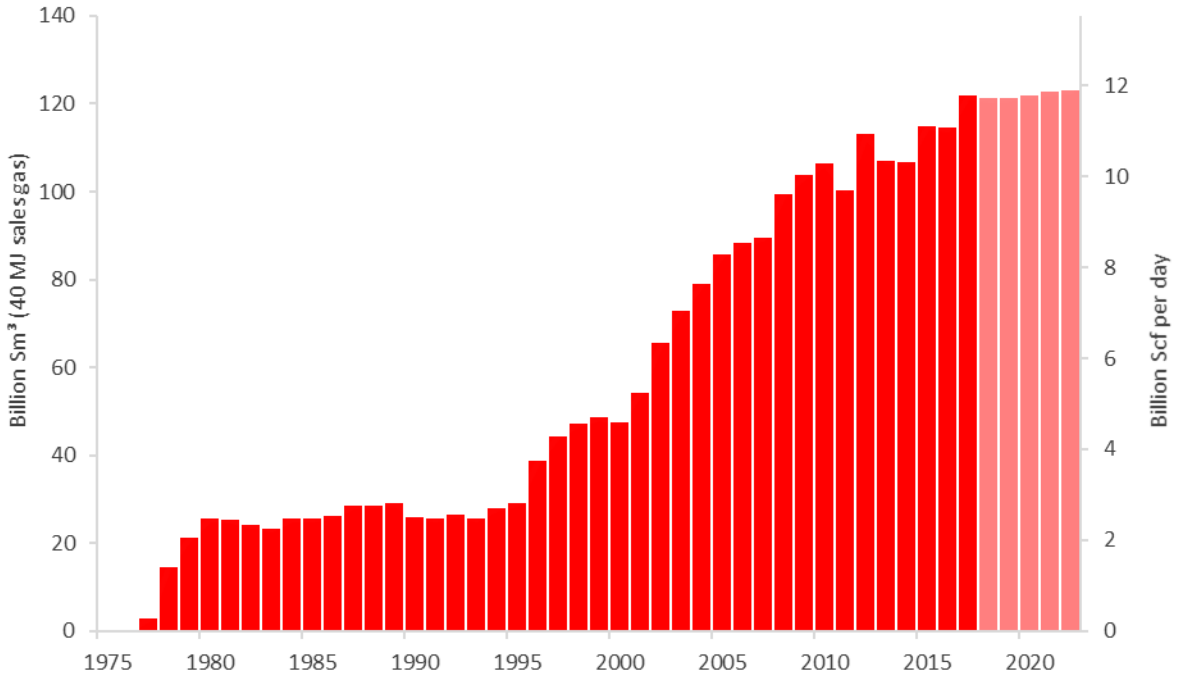


Figure 1-2 Actual and forecast gas sales through 2022

Oil

In 2017, 92 million Sm³ oil (1.59 million barrels per day) were produced, compared with 94.0 million Sm³ (1.61 million barrels per day) the previous year, a reduction of two per cent.

The Norwegian Petroleum Directorate’s forecast for 2017 did not predict a decline in production compared with the previous year. Most of the decline is the result of an unplanned maintenance shutdown on the Goliat field.

For 2018, the Norwegian Petroleum Directorate estimates that oil production will be reduced by an additional 2 per cent, to 90.2 million Sm³ (1.55 million barrels per day). The reduction in oil production is expected to continue towards 2020, while after this, Johan Sverdrup will contribute to a new upswing in production. Uncertainty in production forecasts is particularly linked to the drilling of new wells, start-up of new fields, the ability of the reservoirs to deliver, and regularity on the fields in operation.

Production from approved developments accounts for 90 per cent of the volume expected in the five-year period 2018-2022 (Figure 1-3). The remaining ten per cent is expected to come mainly from additional measures to improve recovery from the fields. Wells that have not yet been decided and optimisation of production strategies are the main contributors to this. In the last years of the period, production is also expected from discoveries where no development decision has yet been made.

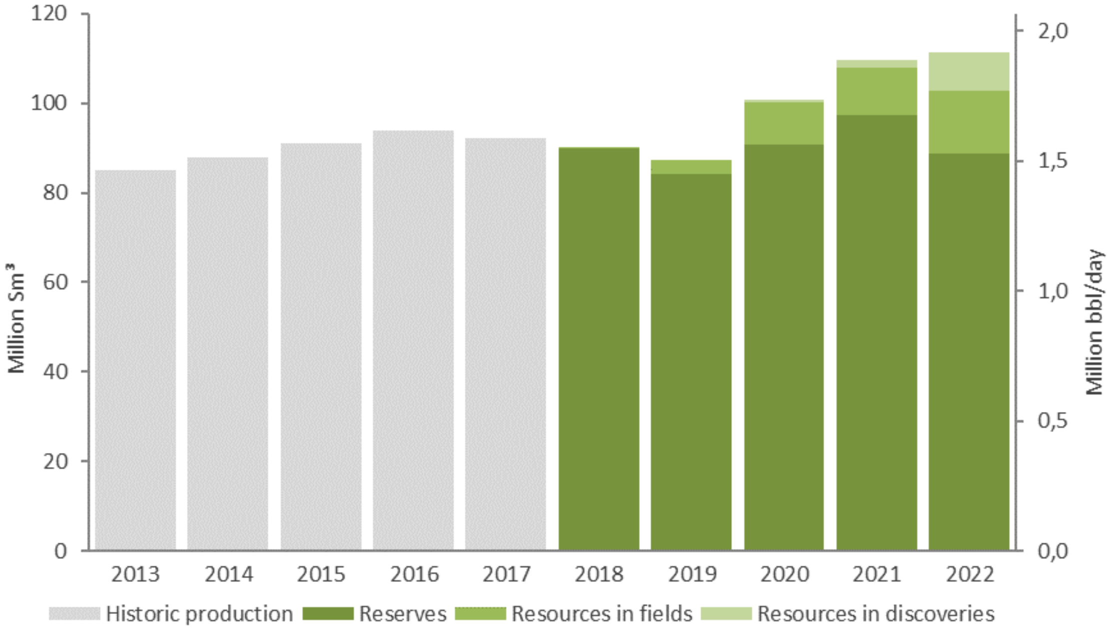


Figure 1-3 Oil production 2013-2022 distributed by maturity

Table 1-1 Forecasted production divided by the different products over the next five years

	2018	2019	2020	2021	2022
Oil (million Sm^3)	90.2	87.2	100.7	109.5	111.3
NGL (million Sm^3 o.e.)	19.8	19.3	18.7	20.1	20.7
Condensate (million Sm^3)	1.8	1.7	1.5	1.5	1.4
Liquid (million Sm^3 o.e.)	111.8	108.2	120.9	131.1	133.4
Liquid (million bbls o.e. per day)	1.9	1.9	2.1	2.3	2.3
Gas (billion 40 MJ Sm^3)	121.2	121.4	122.0	122.7	123.1
Total (million Sm^3 o.e.)	232.9	229.6	242.9	253.8	256.5

Total production towards 2030

Production development in recent years shows that the fields are producing more than previously assumed. This is the result of efficiency measures, particularly within the drilling of wells and regularity on the facilities. More development wells and an assumption of higher gas sales have now been included in the forecast. Several development plans were submitted in late 2017. The Norwegian Petroleum Directorate expects this trend to continue with additional new projects in the time ahead, so that production will come on stream faster than previously thought.

Figure 1-4 shows the latest production forecast compared with the forecast presented one year ago, in connection with The Shelf in 2016. This prognosis reveals relatively flat production development up to 2020. From that point in time, it is presumed that all projects currently under development will contribute to an increase in production. The production level is higher throughout the entire period, compared with the previous forecast. This is due, in part, to the fact that more new measures have been identified on the fields. This mainly relates to the inclusion of more wells in the forecasts.

The contribution from approved petroleum production will remain at a stable, high level for the next five-year period. In the subsequent five years, the production level will rise during the first years of the period due to new measures on the fields. Later on, the contribution from discoveries without a current development decision will increase. Production from undiscovered resources will take on greater significance going towards 2030.

The production level in the years to come is uncertain. It will depend on which measures are implemented on the fields, which discoveries are approved for development, and when they come on stream. New discoveries during the period, their size and how and when they are developed will also have an impact on the production level.

Given these assumptions, total production from the Norwegian shelf will reach a new peak in 2023.

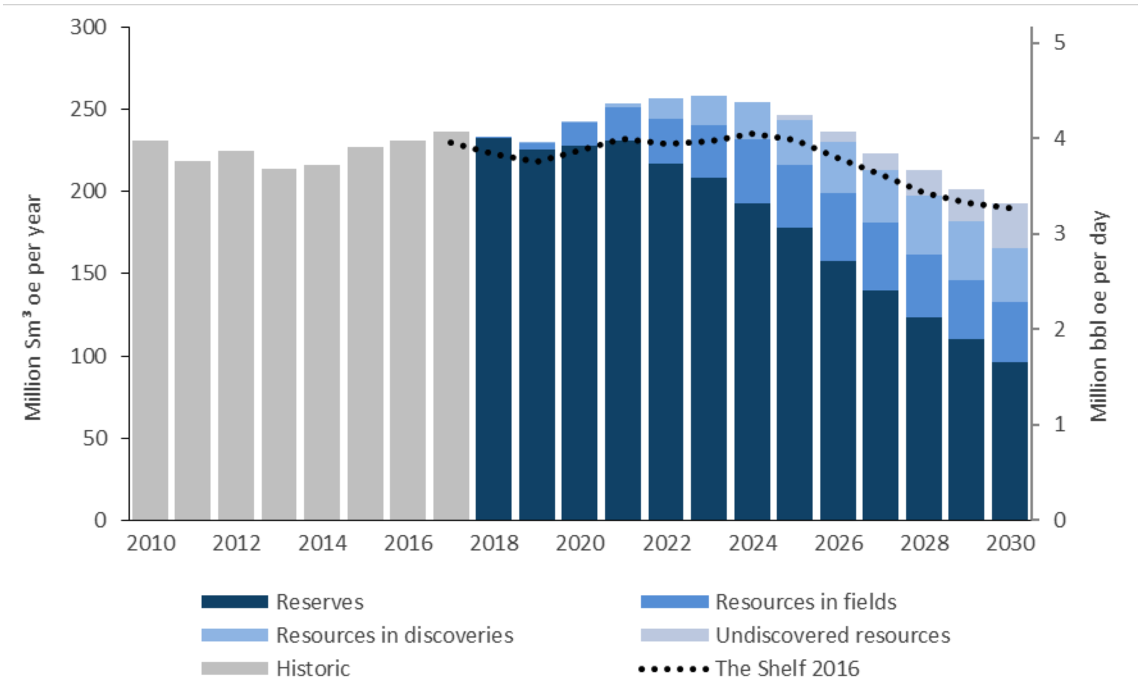


Figure 1-4 Historical and forecast production 2010 - 2030

2 Investment and cost forecasts

The petroleum industry has made a considerable effort to reduce its cost level, which has resulted in substantial savings. The cost level for field developments has declined and there has also been a substantial reduction in both operating and exploration costs.

A combination of many different measures has yielded benefits in the form of increased efficiency, simpler solutions and more use of standardised solutions. All of this contributes to improved profitability. It is important to continue work in this area.

The estimated investment level in 2018 is marginally higher than in 2017. Further growth in investments is expected from 2018 to 2019. As regards exploration activity, we are anticipating moderate growth over the next few years.

Resource growth from new discoveries has been low in recent years. If no new, major discoveries are made, this will result in reduced investment activity over the medium to long term. At the same time, it will be important to mature new projects on operating fields in order to counteract the declining activity level.

Cost level developments

Since 2014, the industry has implemented multiple initiatives to reduce costs, following low profitability over time. The need to reduce costs was amplified by the declining oil price. Oil companies have worked alongside the supplier industry to put in a considerable effort. A broad spectrum of measures have been initiated in both the planning, implementation and operations phases. Individual measures with a relatively modest isolated impact, yield substantial reductions overall.

The decline in development costs is significant; for certain projects, the investments have been cut in half. The common denominator for the projects that are currently being approved, is solid value creation and break-even prices of 30-40 USD/bbl. The overall picture is that new development projects are robust at substantially lower prices than the current level.

Operating costs have also been reduced by about 30 per cent (Figure 2-1) from 2013/2014. The reductions are mainly due to efficiency measures, streamlining and reduced supplier prices.

The NPD's forecasts presume a gradual growth in supplier prices as a consequence of the higher activity level. It is furthermore presumed that some postponed operations activities will have to be carried out. Costs are expected to rise somewhat as a result of this. At the same time, a considerable effort is being made to map and prepare new measures for additional improvements and cost reductions.

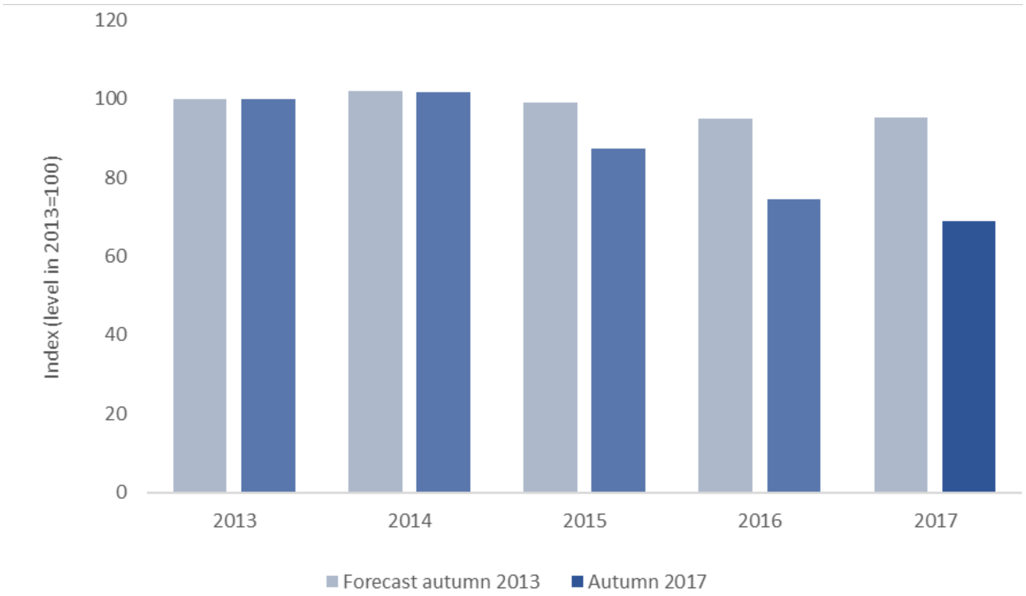


Figure 2-1 Cost development for operating fields

Total investment estimates

Investments have now levelled off. In 2018, we are expecting investments to total approx. NOK 122 billion, which is marginally higher than in 2017, (Figure 2-2). Due in particular to the fact that a number of new development projects are scheduled to start in 2018, there is uncertainty with regard to the overall investment level. The forecast has taken into account that project progress may be somewhat slower during the first investment year than what the companies have presumed in their investment estimates.

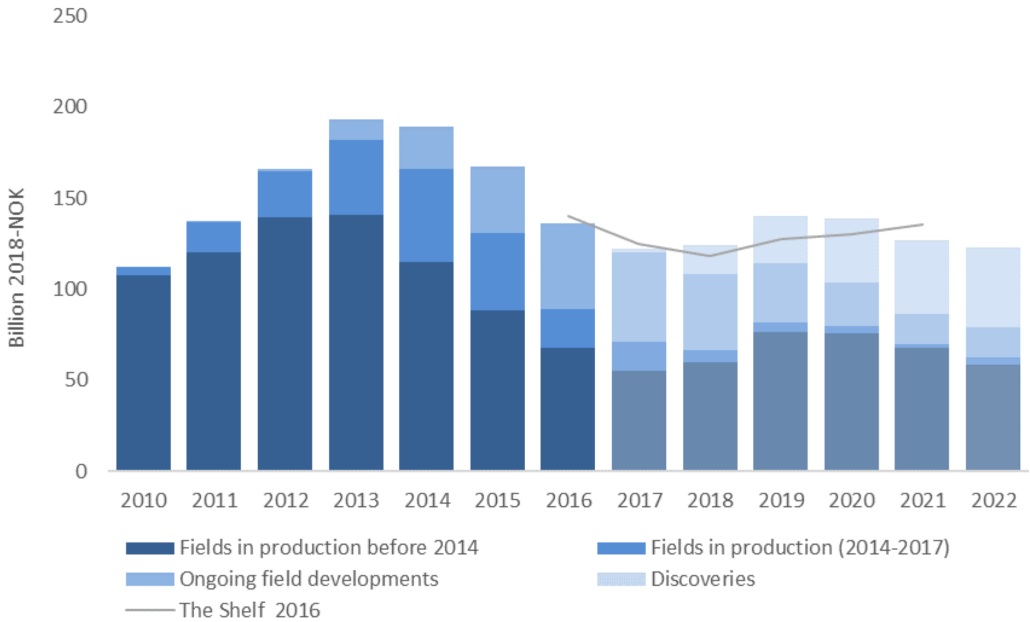


Figure 2-2 Investments excluding exploration, forecast 2017-2022[1]

[1]Fields in operation are divided into two categories in order to clarify that parts of the investments are linked to completion of field development for fields that have recently started producing (fields that came on stream 2014-2017).

Investments are expected to rise to just under NOK 140 billion in 2019 and 2020.

Several major development projects will take place on operating fields over the next few years. The Njord upgrade is under way, and the Snorre Expansion will be a subsea development on Snorre. Other major projects on operating fields include the Ærfugl seabed development on Skarv, Valhall West Flank with a new wellhead platform and investments on Troll (phase III). In addition to these projects, drilling activity will generally be high on operating fields over the next few years.

Several ongoing field developments will also contribute significant investments over the next few years; this particularly applies for Johan Sverdrup construction phases I and II. A number of new field developments are also expected to start in 2018 and 2019 (labelled as discoveries in Figure 2-2), the largest of which is Johan Castberg. These will also contribute substantial investments.

Investments in 2018 and beyond are somewhat higher than the estimate presented in the Shelf in 2016, because of several new projects starting somewhat earlier than what was presumed in 2016.

Whereas investments in new facilities resting on the seabed and floating facilities will decline in the years to come, investments in new seabed facilities will increase. Investment in existing facilities and new development wells are also expected to increase (Figure 2-3).

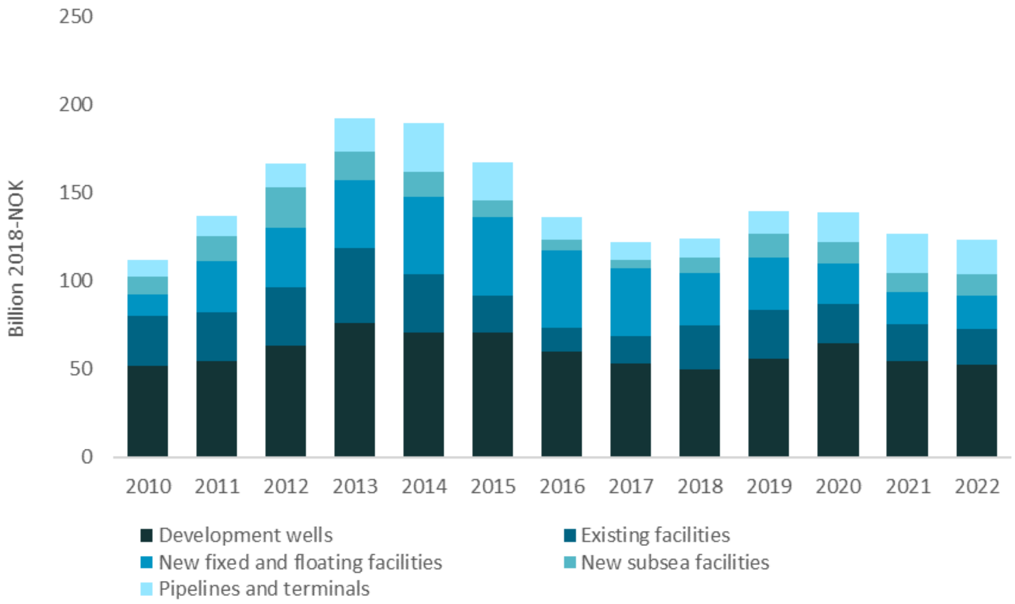


Figure 2-3 Investments excluding exploration, different investment categories, forecast for 2017-2022

Seven development plans were submitted for authority approval in December 2017: [2]Skogul, Fenja, Yme and Johan Castberg as new field developments and Valhall West Flank, Ærfugl (Skarv) and Snorre Expansion as projects on operating fields.

[2] Development plans were submitted earlier in 2017 for the the Bauge, Njord and Ekofisk 2/4 VC projects.

A number of projects are also expected to be decided over the next few years. This e.g. includes Johan Sverdup construction phase II, Troll phase III and new field developments such as 35/9-7 (Skarfjell/Nova), 36/7-4 (Cara), 6407/6-6 Mikkel South and several discoveries in the area between the Oseberg and Alvheim fields in the North Sea.

The plans submitted to the authorities in the autumn of 2017 and the development projects expected to be submitted in 2018 and 2019 have a total projected investment level of about NOK 240 billion. New facilities and wells constitute the majority of these investments (Figure 2-4).

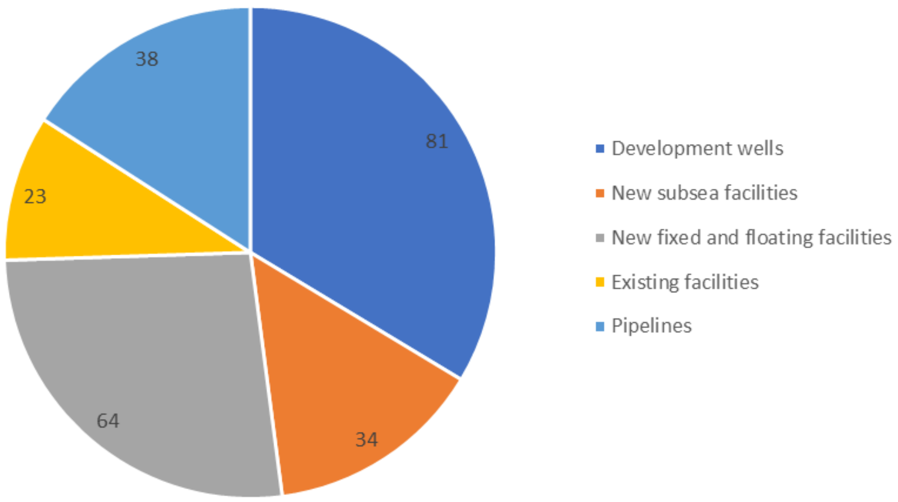


Figure 2-4 Total investment in new field development projects (NOK billion). Includes projects with submitted plans for development and operations (PDOs) or exceptions from this in December 2017 and anticipated plans for 2018 and 2019.

Development decisions were made for multiple discoveries between 2010 and 2014, including older discoveries. The number of new discoveries has also declined in recent years. If new, major discoveries are not made relatively quickly in mature areas, where the lead time from discovery to development decision can be short, the lack of new developments will eventually result in falling investments over time. This also applies to operating fields. A number of major field projects will be carried out over the next few years, but there are few new, major projects being considered. With a study phase lasting several years from feasibility study to investment decision, this could mean less development activity on operating fields.

Exploration costs

There was a minor reduction in exploration costs from 2016 to 2017. Thirty-six exploration wells were spudded in 2017 with overall costs of about NOK 19 billion (Figure 2-5).[3] In comparison, 36 exploration wells were also spudded in 2016, and exploration costs totalled NOK 22 billion. Based on the companies' plans, we expect the number of spudded exploration wells in 2018 to remain at about the same level as 2017. Over the next few years, we have presumed gradual growth in the number of exploration wells and associated costs. This is based on the assumption of increased exploration profitability linked to developments in costs and the price of oil.

The average cost per exploration well was around NOK 240 million in 2017, which is about half the cost per well compared with 2013/2014. This change provides a rough estimate of the cost level reduction, although the composition of exploration wells may have changed somewhat. Well length is very important for the cost of an exploration well, and changes in average well length will therefore affect the cost per exploration well.

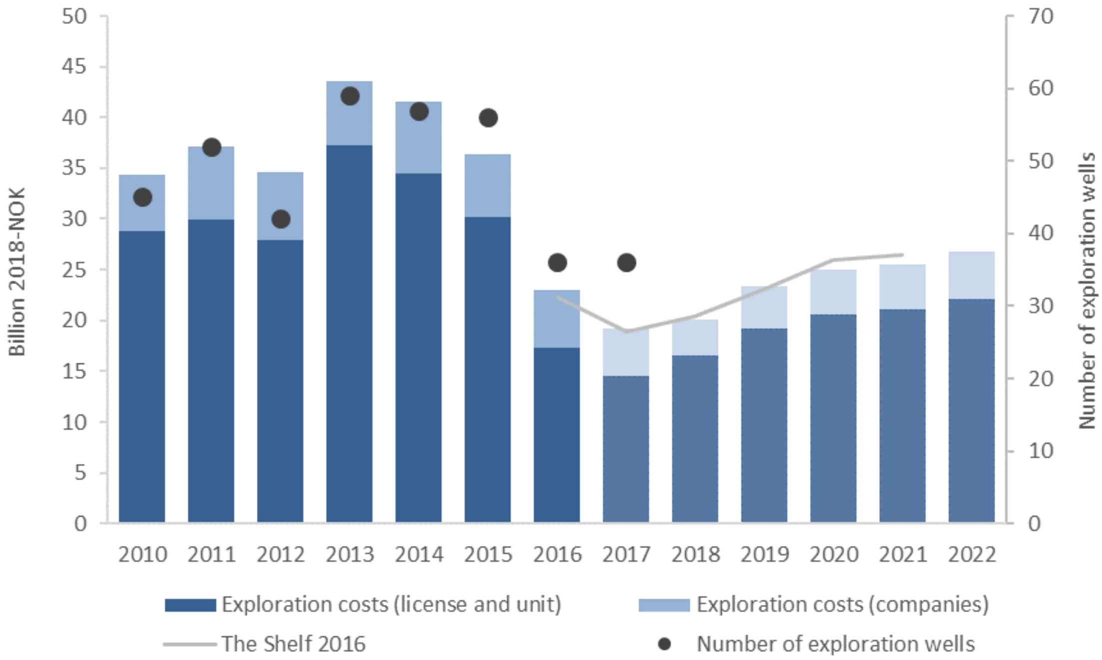


Figure 2-5 Estimated exploration costs, forecast 2017-2022

[3]Exploration costs include both company and licence-related exploration costs, cf. Figure 2-5. Company-related exploration costs are often incurred before the production licence is awarded, for example costs for purchasing and interpreting seismic data. However, the majority of exploration costs are incurred after the production licence is awarded. Of these, drilling of exploration wells is the dominant item.

Operating costs

85 fields were in production at the end of 2017. This is in addition to the operation of pipelines and onshore facilities. The total operating costs were NOK 52 billion in 2017. After a period of reduction, operating costs are now expected to level off and then gradually increase. This is primarily due to new fields starting production.

Compared with the projection in the Shelf in 2016, the new projection is somewhat lower than the estimated level from 2020 (Figure 2-6). This is due to both a lower estimate for operating costs on operating fields and a reduced operating cost estimate for new fields.

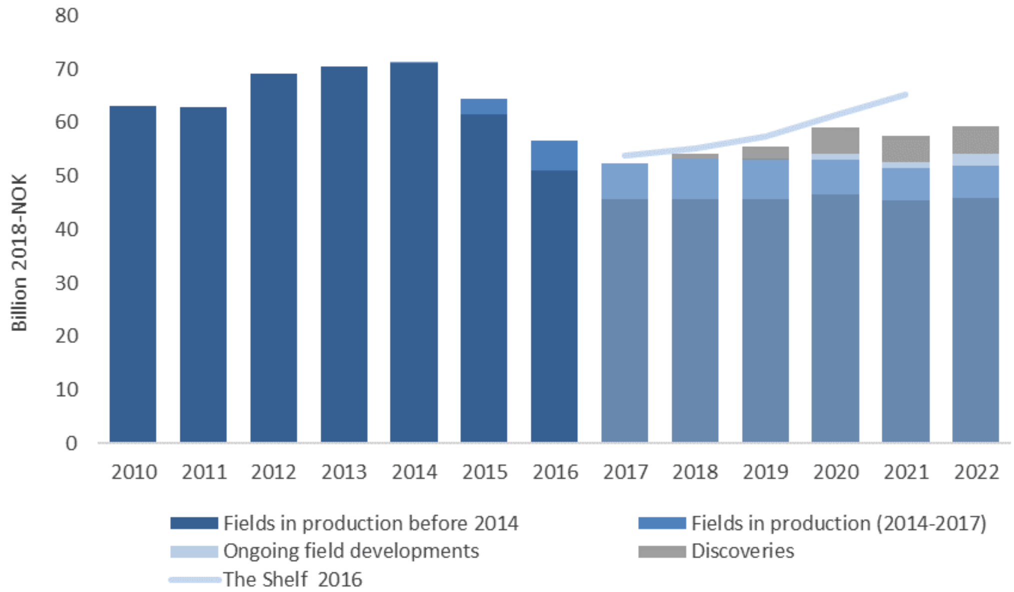


Figure 2-6 Operating cost specified by field status, forecast 2017-2022

Overall cost development estimate

Figure 2-7 shows the overall estimate for operating costs, investments, exploration costs, shutdown and disposal costs, as well as other costs. The Other costs category includes certain smaller items, such as concept studies and preparing for operations.

Overall costs in 2017 totalled about NOK 210 billion. As a result of increased estimates for investments and exploration costs, the overall costs will increase from 2018 to 2020. In comparison, overall costs in 2014 totalled NOK 325 billion.

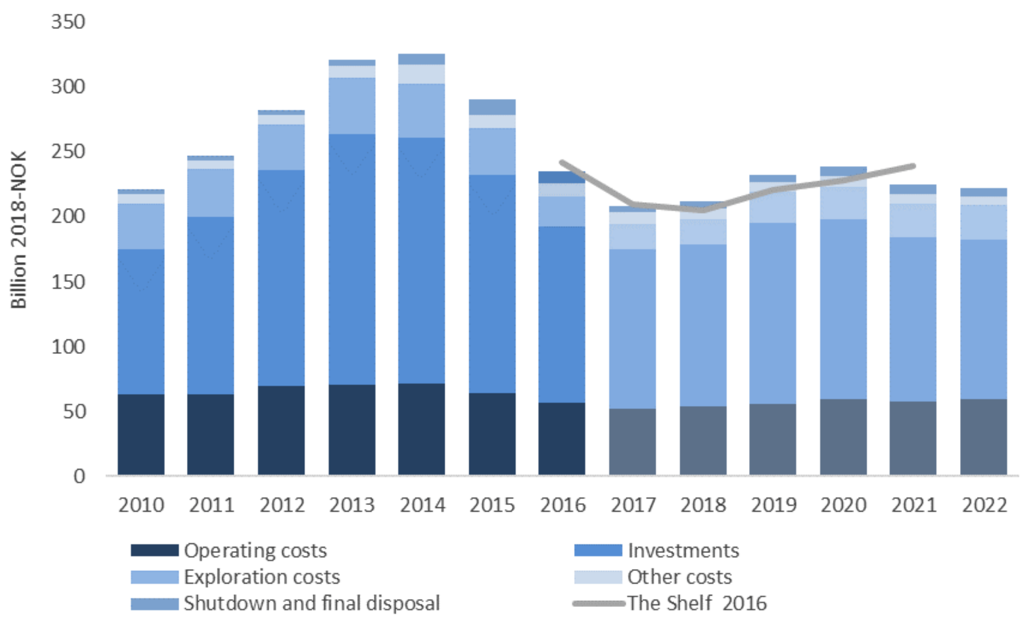


Figure 2-7 Overall costs, forecast 2017-2022

The reason that cost projections for the next few years are somewhat higher than the projections given last year, is quicker start-up of new development projects and thus higher investments than presumed in the Shelf in 2016.

3 Development and operations

Increased activity with improved cost control

The Norwegian Petroleum Directorate is concerned with responsible resource management through cost efficiency and cost control. Cost-effective solutions make profitable oil and gas production possible. On the other hand, cost cuts must not prevent profitable measures to increase the production.

In recent years, the petroleum industry has worked hard to reduce costs. This has contributed to the implementation of new projects on existing fields and new field development decisions. Continued good profitability and a high activity level on the Norwegian shelf requires sound cost-effectiveness over a long period of time. At the same time, the industry must ensure that further cost reductions do not have an adverse impact on the opportunity for future value creation. Good project execution is always important for profitability and for responsible resource management.

Other profitable projects

Development projects costs have been cut by 30 to 50 per cent over the last few years. The price of oil has increased during the same period, leading to companies seeing more profitable projects.

However, requirements related to short-term returns, capital restrictions in the companies or unnecessarily high risk linked to project implementation can make it challenging to secure approval for major and minor investment decisions in the production licences.

The authorities are concerned with ensuring that the chosen solutions provide the highest returns overall, and with emphasising the importance of maintaining a long-term perspective rather than looking at what yields the highest returns in the short term.

Implementing initiatives is worthwhile

The oil companies on the shelf are responsible for exploration, development and operations, and do a great job. Nevertheless, it is vital that the Norwegian Petroleum Directorate keeps a close eye on the activities and contributes to ensuring decisions that safeguard the values for society in the best possible way.

One example of this is the authorities' follow-up of the Snorre field. It has been producing since 1992, and still contains vast profitable resources. To ensure they are produced, an amended Plan for Development and Operation (amended PDO) was submitted on 21 December 2017. This development plan comes as a result of a determined effort over the last 12-15 years, by both the companies and the authorities.

The development is one of the largest projects for improved recovery on the Norwegian shelf. The project will contribute to extended field operation and will yield major revenues for both the companies and the Norwegian society.

The further development of the Snorre field yields good resource management, in accordance with the ambitions in *Storting Report No. 28 (2010-2011) – The Petroleum Report*and Proposition 114 S (2014-2015) "Norway's largest industrial project – development and operation of the Johan Sverdrup field, including status of the oil and gas activities".

Snorre is an example worthy of imitation. The authorities believe that there are also other mature fields on the shelf with the potential for further development through drilling of more development wells that yield improved recovery of oil and gas.

The Norwegian Petroleum Directorate will continue the work to increase value creation on both mature fields and new developments – not least through measures for improved recovery and phase-in of additional resources.

Area perspective yields new opportunities

In order to maximise value creation, best possible use of existing infrastructure such as pipelines and available process capacity on the platforms is necessary. It is vital that time-critical oil and gas resources, for example minor discoveries near aging infrastructure, are proven and developed before the facilities are shut down and removed.

Coordination across production licences can result in advantageous area solutions. Such solutions can contribute to achieving profitability for discoveries that would not otherwise have been developed. The authorities are interested in ensuring that decisions in different production licences safeguard a comprehensive area perspective.

New technology should be tested and applied

In the summer of 2017, the Norwegian Petroleum Directorate published a resource report, where one of the main messages was that there are still vast values to be extracted on the Norwegian shelf.

The authorities expect the companies to extract all the resources in discoveries and fields that can contribute value to our society, not just “the easy barrels”. There are large volumes of petroleum where production is not currently profitable. These are “technical resources” that could potentially be produced with technology that has not yet been tested or qualified for use on the Norwegian shelf.

With current plans and applied technology, about half of the oil in the oil fields will be left in place. There are also large oil and gas deposits in tight reservoir zones where production is not profitable. By developing and utilising new technology, parts of these resources can also become profitable.

Many fields are far into their production phase and may be nearing shutdown. Therefore, the Norwegian Petroleum Directorate believes that it is urgent that pilot trials using new technology are carried out. This is necessary to verify applicability, to reduce risk and to demonstrate improved recovery potential through various advanced injection methods and new technology, before the relevant fields are shut down.

The Norwegian shelf has been a laboratory for testing and application of new technology. The Norwegian Petroleum Directorate wants this to continue. New technical solutions are a decisive factor in ensuring that even more of the proven oil and gas is profitable to produce.

New fields are being developed

There are 85 producing fields on the Norwegian shelf, 66 in the North Sea, 17 in the Norwegian Sea and 2 in the Barents Sea. These are profitable fields that contribute revenues for both the companies and the Norwegian state. In 2017, five new fields started producing.

Nine field developments are currently ongoing:

- North Sea: Johan Sverdrup, Martin Linge, Utgard, Oda, and Hanz
- Norwegian Sea: Aasta Hansteen, Dvalin, Bauge and Trestakk

The authorities approved eight Plans for Development and Operation (PDOs) in 2017. In total, these projects have an investment framework of nearly NOK 50 billion.

In 2017, the authorities received a record-high number of new development plans. The ten development plans have a total investment value of NOK 125 billion. *

(Njord (Njord future), Bauge and Ekofisk 2/4 Victor Charlie (improved recovery project) were both submitted and approved in 2017.)*

New fields in production

The five new fields that started producing in 2017 are Gina Krog, Flyndre, Sindre, Byrding and Maria (Maria started producing in December).

Gina Krog is an old oil and gas discovery from 1974 near the Utsira High in the North Sea. Technology development and new subsurface information contributed to a revitalisation of the discovery, where Statoil is the operator. Gina Krog is well-facilitated for phasing-in current and future discoveries in the area.

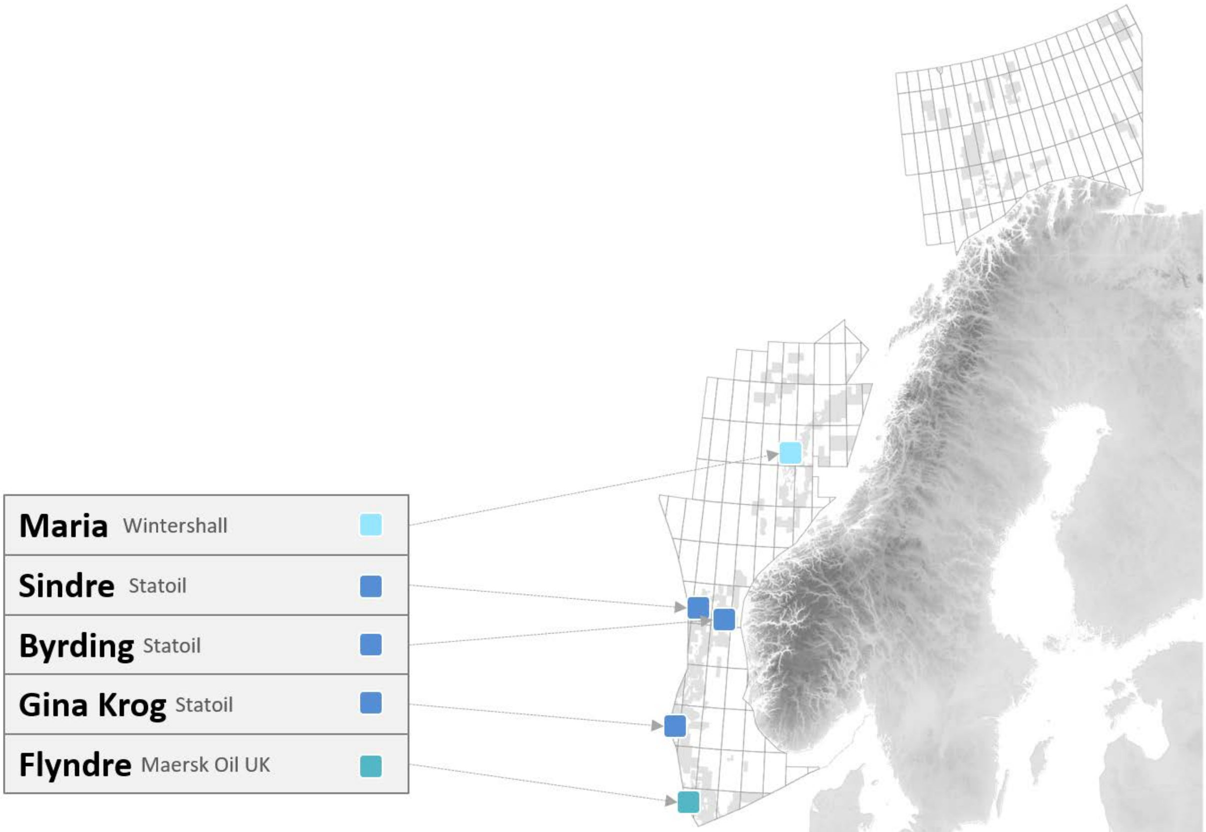
The Maria field in the Norwegian Sea is Wintershall's first development on the Norwegian shelf as an operator. The development became NOK 3.7 billion cheaper than expected in the PDO. Production started nearly one year ahead of the original plan. The Maria development is an example of how cooperation between the licensees can lead to excellent utilisation of the infrastructure in an area and contribute to increased value creation. Utilisation of different host facilities has made the Maria development possible.

The other three fields that have started producing are smaller, but important fields that effectively exploit existing infrastructure in the area.

Flyndre is a minor oil field in the Greater Ekofisk Area in the North Sea that was proven in 1974. The field is located on the border between the UK and Norwegian shelves, and is developed with a subsea well tied to the Clyde facility on the UK shelf. Production start-up was in March 2017. Maersk Oil UK is the operator.

Sindre is a minor oil field that is located northeast of Gullfaks in the northern part of the North Sea. The field was proven through the drilling of a long well from the Gullfaks C platform, and production started through this well in May, after a PDO exemption was granted. Statoil is the operator.

Byrding is an oil and gas field southwest of Gjøa in the North Sea. The field is developed with a two-branch well that was drilled from an available slot on the existing subsea template on Fram H-Nord. The wellstream is routed via the Fram infrastructure to Troll C. Statoil is the operator.



Approved Plans for Development and Operation (PDO)

In 2017, the authorities approved eight Plans for Development and Operation (PDOs) for the fields Utgard, Byrding, Oda, Dvalin, Trestakk, Bauge and amended PDOs for Njord further development and Ekofisk 2/4 Victor Charlie.

All the development plans relate to fields and resources that are tied-in to existing infrastructure, and this contributes to effectively exploiting available capacity. At the same time, profitability increases, along with the lifetime for the relevant platforms that will process oil and gas from the new fields. It also provides a possibility for additional measures that can contribute to extend tail production from these fields.

In addition, five fields have received a PDO exemption; Goliat (Snadd), Martin Linge (Herja and Hervor), Sindre, Snefrid north and Troll Brent B.

Utgard is a gas and condensate field in the Sleipner area in the North Sea. It extends across the Norwegian-UK continental shelf border and is estimated to contain about nine million standard cubic metres of oil equivalents (Sm^3 o.e.). The largest percentage of the reserves in Utgard is located on the Norwegian side. The development will be tied-in to facilities on Sleipner. The expected investment is nearly NOK 1.9 billion (Norwegian share). Production start-up is scheduled for the fourth quarter of 2019. Statoil is the operator.

Byrding is an oil and gas field southwest of Gjøa in the North Sea. It is estimated to contain about 1.8 million Sm^3 o.e.. Byrding is developed using an existing subsea template in the Fram area. The expected investment is nearly NOK 1 billion. Statoil is the operator.

Oda is an oil field south of Ula in the North Sea. The recoverable resources are estimated at 7.5 million Sm^3 o.e.. The investments for the development are estimated at about NOK 5.4 billion. The field will be tied-in to Ula, and production is scheduled to start in the third quarter of 2019. Spirit Energy is the operator.

Dvalin is a gas field near Heidrun in the Norwegian Sea. The recoverable resources are estimated at about 18 billion Sm^3 of gas. The field will be tied-in to Heidrun. Investments are expected to reach more than NOK 10 billion. Production start-up is scheduled for the fourth quarter of 2020. DEA is the operator.

Trestakk is an oil field near Åsgard in the Norwegian Sea. Recoverable resources are estimated at 10.5 million Sm^3 of oil. The field will be tied-in to the Åsgard A ship. Expected investments total about NOK 5.5 billion. Production start-up is scheduled for the second quarter of 2019. Statoil is the operator.

Bauge is an oil field near the Njord field and the tied-in seabed development Hyme in the Norwegian Sea. Bauge will be tied-in to both these fields. The recoverable resources are estimated at 7.9 million Sm^3 of oil, 1 million tonnes of NGL and 1.9 billion Sm^3 of gas. The investments are estimated at NOK 3.9 billion. Production start-up is scheduled for the fourth quarter of 2020. Statoil is the operator.

Njord in the Norwegian Sea was shut down in 2016 due to structural problems with the Njord A platform. Njord A and Nord B were towed to shore to be upgraded so that they can produce for several more years. The remaining recoverable resources are estimated at 5.1 million Sm^3 of oil, 13.2 billion Sm^3 of gas and 4.1 million tonnes of NGL. The investments are estimated at about NOK 15 billion. Production start-up is scheduled for the fourth quarter of 2020. Statoil is the operator.

Ekofisk 2/4 Victor Charlie is a new subsea template for water injection and drilling and completion of four new injection wells. The chosen solution is well adapted to the need for a quick increase in water injection on Ekofisk and will contribute to ensuring high recovery and good resource utilisation from the field, as well as preventing resources from being squandered. According to plan, water injection from 2/4 VC will improve recovery on Ekofisk by 2.7 million Sm^3 of oil equivalents. The expected investment is nearly NOK 2.3 billion. ConocoPhillips is the operator.

Plans for development and operation

The authorities received 10 new development plans (PDO applications) over the course of 2017. These are Njord further development, Bauge, Ekofisk 2/4 Victor Charlie, Valhall flank west, Yme, Skogul, Snorre further development, Ærfugl, Fenja and Johan Castberg. Of these, Njord, Ekofisk 2/4 Victor Charlie, Snorre further development and Yme are amended PDOs.

Snorre further development in the North Sea is one of the largest projects for improved oil recovery on the Norwegian shelf. Snorre is one of the fields on the shelf with the greatest remaining oil volumes. The project involves an extensive subsea development with six new subsea templates tied-in to the Snorre A platform. The project also comprises upgrading the Snorre A platform and increased gas injection. This can yield nearly 30 million Sm^3 more oil. The investments are estimated at NOK 19.3 billion (2017-NOK). With this project, the lifetime of the field will extend to beyond 2040. The PDO was submitted in December 2017. Statoil is the operator.

Johan Castberg in the Barents Sea was proven in 2011. The discovery will be developed on the seabed with ten subsea templates and two satellites tied-in to a floating production storage and offloading vessel (FPSO). Expected production will yield 88 million Sm^3 of oil, and recovery could be significantly improved by drilling more wells. The field will be operated from Harstad and have operations and helicopter transport bases in Hammerfest. The lifetime of the field is expected to extend beyond 2050, and investments are estimated at about NOK 49 billion. The PDO was submitted in December 2017 and production is scheduled to start in 2022. Statoil is the operator.

Valhall flank west
The development will take place with an unmanned wellhead platform that will be controlled from the field centre on the Valhall field. Wellhead platforms have previously been installed on the southern and northern flanks of Valhall. The new facility will have twelve well slots and six new wells will be drilled. This will yield six available slots for future wells. The development will increase the reserves by about 10 million standard cubic metres of oil.The expected investment is nearly NOK 5,7 billion. Drilling will be carried out with a jack-up drilling rig and will take place for 1.5-2 years. The planned drilling start-up is in the third quarter of 2019. The PDO was submitted in December 2017. Aker BP is the operator.

Fenja (Pil/Bue) is two oil and gas discoveries in the Norwegian Sea. Recoverable oil reserves amount to about 11 million Sm^3 of oil and 3.4 billion standard cubic metres of gas. The investment estimates are NOK 10.2 billion. The PDO was submitted in December. The planned production start-up is in 2021. VNG Norge is the operator.

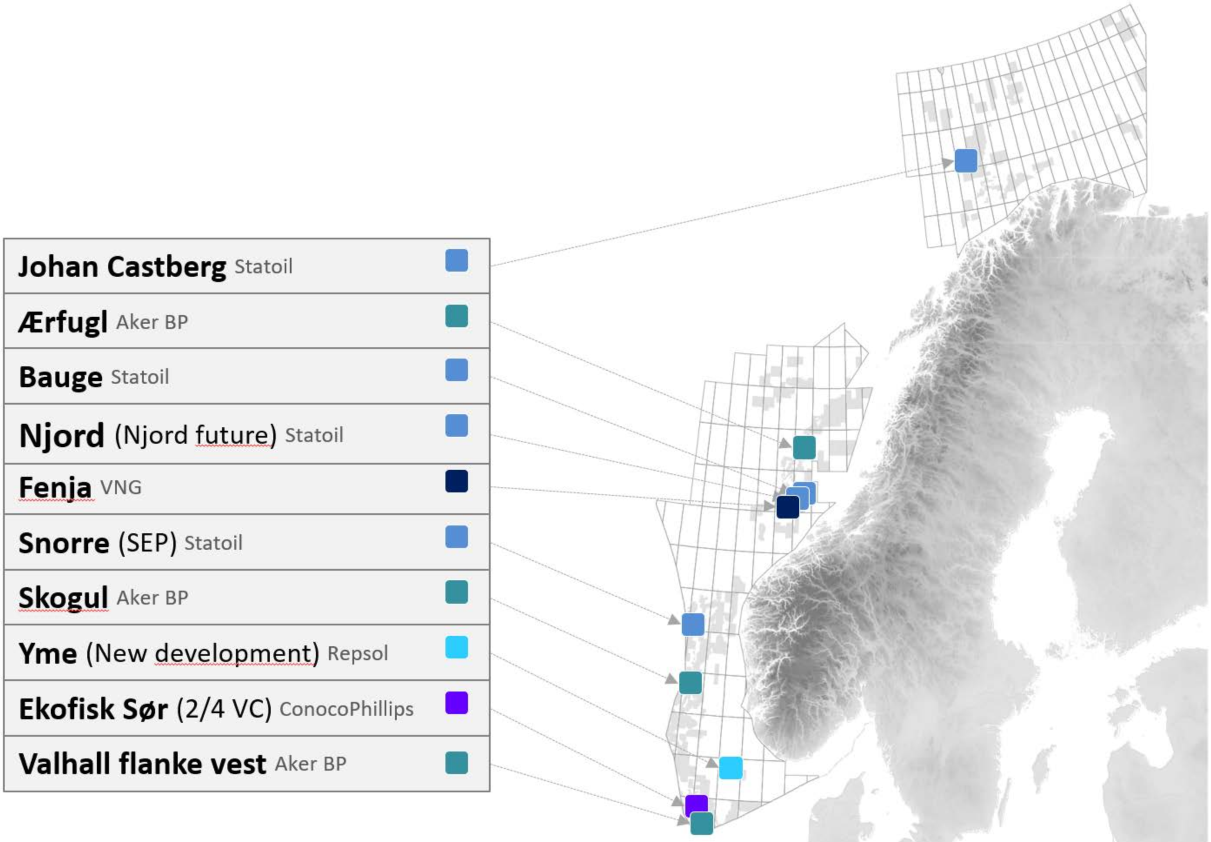
Ærfugl (Snadd) is a gas discovery covering 60kilometres west of the Skarv field in the Norwegian Sea. The plan is to develop Ærfugl in two phases due to the gas processing capacity on the Skarv production vessel. Phase 1 (south) is scheduled to start production in 2020 and Phase 2 (north) in 2023. Phase 2 also includes Snadd Outer in PL212E, which has the same owners. Total recoverable gas reserves for both phases are 35 billion Sm^3, and the investment costs are estimated at NOK 8.5 billion. The PDO was submitted in December 2017. Ærfugl is located in Skarv Unit, where Aker BP is the operator.

The Yme field in the North Sea was in production from 1996 to 2001. It was then shut down, and the facilities were removed. The plan in the new development project is to use a jack-up facility with a drilling and process system to produce the remaining resources. The expected investment is nearly

NOK 8.2 billion. Recoverable oil reserves are about 10,3 million Sm3. The plan was submitted in December 2017. Repsol is the operator.

Skogul

Skogul in the North Sea is a minor field with a reserve basis of approx. 1.5 million standard cubic metres of oil.The investment is expected to reach NOK 1.5 billion. Skogul is a subsea field that will be developed with a two-branch well. Oil and gas from Skogul will be processed on the floating production facility Alvheim FPSO. The PDO was submitted in December 2017 and Aker BP is the operator.



Cessation and shut down of fields

Cessation plans for the Trym and Gyda fields were delivered in the first half of 2017.

The gas and condensate field Trym is located in the southern part of the North Sea, three kilometres from the border with the Danish sector.

Gyda is an oil field in the southern part of the North Sea, between Ula and Ekofisk. The disposal decision was made in June, and production is scheduled to shut-down in 2018. A disposal decision has also been made for the old living quarters platform on Valhall in the North Sea.

4 Exploration

Record number of exploration wells in the Barents Sea

A total of 34 exploration wells were completed in 2017, a decline of 3 from the previous year. Based on the companies' plans, the number of exploration wells in 2018 is expected to remain at approximately the same level as in 2017.

Half of the wells drilled in 2017 were drilled in the Barents Sea. This is a new record for the number of exploration wells in the Barents Sea. Twelve wells were drilled in the North Sea and five wells were drilled in the Norwegian Sea. For comparison, the wells drilled in 2016 were distributed as follows: five in the Barents Sea, three in the Norwegian Sea and 29 in the North Sea.

Of the 34 wells completed in 2017, 23 were wildcat wells and 11 were appraisal wells.

Several small discoveries

Eleven new discoveries were made in 2017. Six of the discoveries were made in the Barents Sea, three in the Norwegian Sea and two in the North Sea (Figure 4-1). These discoveries were consistently small, and the total resources amount to between 24 and 59 million standard cubic metres (Sm^3) of oil equivalents.

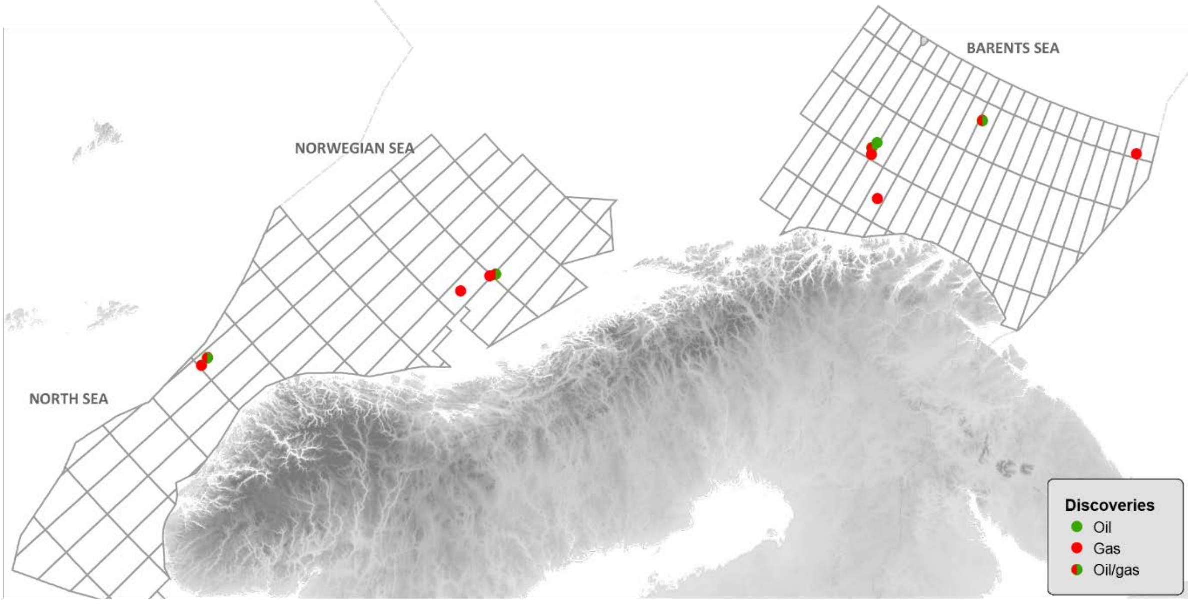


Figure 4-1 Eleven discoveries were made in 2017.

The largest discovery in 2017 is Lundin's oil and gas discovery in wildcat well 7219/12-1 (Filicudi) in the Barents Sea. Preliminary estimates place the size of this discovery between 10 and 20 million Sm^3 of oil equivalents.

Several of the discoveries in the North Sea and the Norwegian Sea are located in areas where they can be developed via existing infrastructure. Here, even small discoveries can contribute significant value creation.

In 2018, submitted plans indicate that most exploration wells will be drilled in the North Sea. If petroleum production is to be maintained at the current level beyond 2025, it is absolutely essential that additional profitable resources are proven, also larger discoveries.

The authorities' contribution towards maintaining a high level of exploration activity is to ensure that the companies have good access to data, stable framework conditions and, not least, regular access to attractive acreage. The APA area was substantially expanded in 2017, with the largest expansion in the Barents Sea.

Most to be found in the North

The Norwegian Petroleum Directorate regularly updates its estimates of undiscovered resources. The update performed in 2017 is based e.g. on the NPD's mapping of the unopened areas in the Barents Sea North. The update reveals that the resources in the Barents Sea are now around 80 per cent higher than in the previous analysis from 2015, while the estimate is approximately the same for the North Sea and the Norwegian Sea.

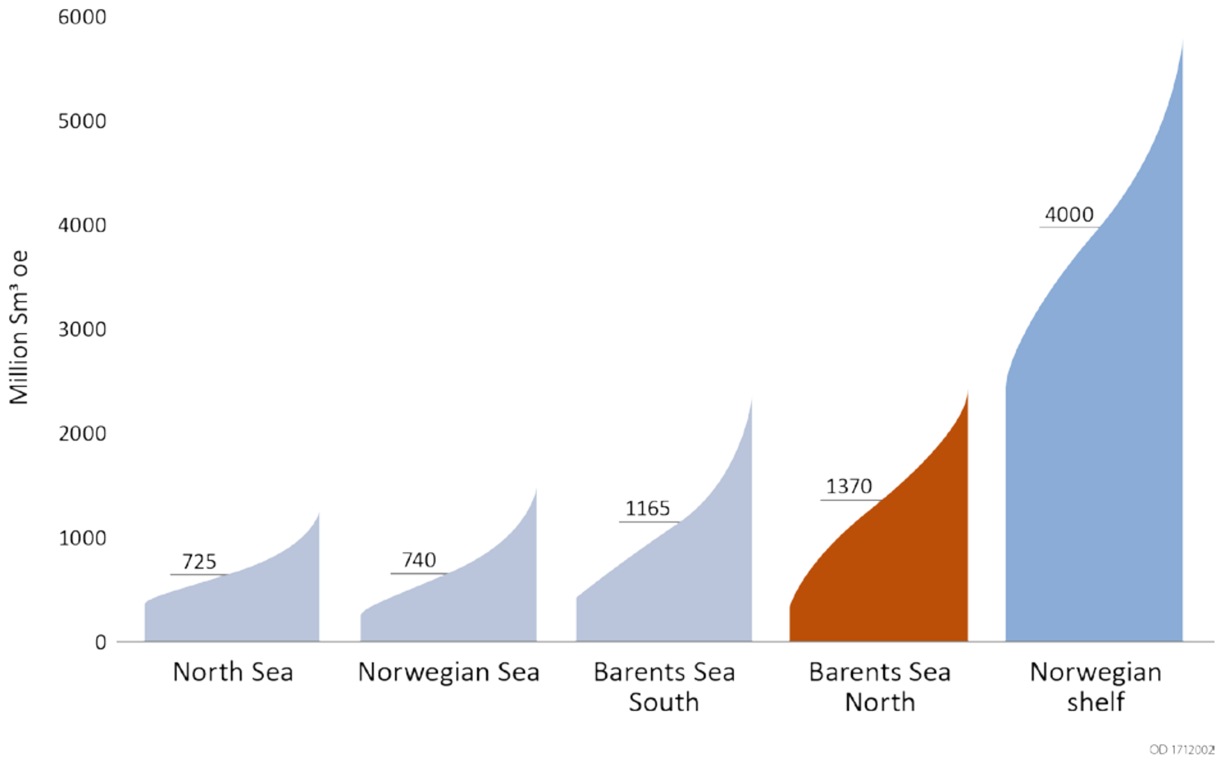


Figure 4-2 Estimate of undiscovered resources on the Norwegian shelf

Nearly two-thirds of the undiscovered resources are located in the Barents Sea (Figure 4-2). Therefore, this area will play an important role if we are to prevent declining production from 2025. The Norwegian Petroleum Directorate has continued its mapping of the Barents Sea North in 2017. More than 4500 kilometres of 2D seismic have been acquired on the Gardarbank High East, northeast of Bjørnøya and south of Hopen.

Norwegian shelf is still attractive

The number of applications and awards in recent licensing rounds reveals continued significant interest in exploration on the Norwegian shelf.

Fifty-six production licences were awarded in APA 2016. As many as 39 companies applied for acreage in APA 2017, and they submitted a record number of applications.

Eleven companies applied for acreage in the 24th licensing round. The announced blocks are located in immature areas, and the applicant list is dominated by large and medium-sized companies with good technical and financial capacity to explore such areas.

Discoveries 2017

North Sea
In the North Sea, 12 exploration wells were completed in 2017 and two discoveries were made. The 34/10-55 S (Albiorix) oil and gas discovery is situated northeast of the Gullfaks field in the Statfjord Group and the Lunde formation, and the 34/11-6 S (Valemon Vest) gas discovery is situated near the Valemon field in the Brent Group. See Table 4-1.

Both discoveries can be produced from nearby infrastructure.

Norwegian Sea
Five wells were completed in the Norwegian Sea. Three discoveries were made.

The largest discovery was 6608/10-17 S (Cape Vulture). The discovery was made in two sandstone layers in the Lange formation. The licensees will consider further delineation of the discovery with a view towards development via the production and storage vessel (FPSO) on Norne.

Well 6507/3-12 (Osprey) is a minor gas discovery in the Lysing formation. The discovery is situated near the Norne field. Another minor gas discovery was also made in 6507/8-9 (Carmen), immediately northeast of the Heidrun field. The reservoir in this discovery is the Åre formation. See Table 4-1.

All the discoveries are located fairly close to existing infrastructure.

Barents Sea
There has been a high level of exploration activity in the Barents Sea in 2017, with 17 completed wells. Six discoveries were made.

Well 7219/12-1 (Filicudi) proved a gas and oil-filled reservoir in the Nordmela and Tubåen formations. The discovery is located between well 7220/11-1 (Alta) and the Johan Castberg field.

Well 7219/9-2 (Kayak) proved oil in the Kolje formation. This discovery opens the door for further exploration in the area within the same play. Kayak can be tied in to the Johan Castberg field. See Table 4-1.

Well 7325/4-1 (Gemini North) is a small oil and gas discovery. In addition to proving new resources in the Wisting area, it was important to expand knowledge about what the geophysical measurements conducted in the area (electro-magnetic data) mean, compared with measurements taken on the Wisting discovery.

Well 7435/12-1 (Korpfjell) is the first wildcat well in the Barents Sea Southeast, after the area was opened for exploration activity in 2013. This is also the northernmost wildcat well ever drilled on the Norwegian shelf. It is located in a new exploration area, far from other wells, and it thus constitutes an important data point. The well proved gas in the Stø formation. See Table 4-1.

7317/9-1 (Koigen Central) was drilled far to the northwest in a relatively unexplored area. This well was dry.

Two minor gas discoveries were also made, 7121/8-1 (Blåmann) in the Hammerfest Basin and 7219/12-2 S (Hufsa Nordmela) in the southern part of the Loppa High.

Table 4-1 Recoverable resources in new discoveries in 2017

Discovery	Operator	Hydrocarbon type	Oil/condensate (million Sm3)	Gas (billion Sm3)
34/10-55 S	Statoil	Oil and gas	<1	<1
34/11-6 S	Statoil	Gas		0,4-1,8-3,3
6608/10-17 S	Statoil	Oil and gas	0,1-3,2-9,6	0,4-1,1-1,6
6507/3-12	Statoil	Gas		0,9-1,1-1,8
6507/8-9	Statoil	Gas		0,6-0,8-1,2
7219/9-2	Statoil	Oil	3,8-5,5-7,5	
7219/12-1	Lundin	Oil and gas	9,1-14,3-18,9	0,9-1,1-1,3
7219/12-2 S	Lundin	Gas		<1
7435/12-1	Statoil	Gas		7,9-9,5-11,4
7325/4-1	Statoil	Oil and gas	<1	<1
7121/8-1	Statoil	Gas		0,3-1,6-2,6
Total			13,0-24,1-36,0	11,4-18,5-23,2