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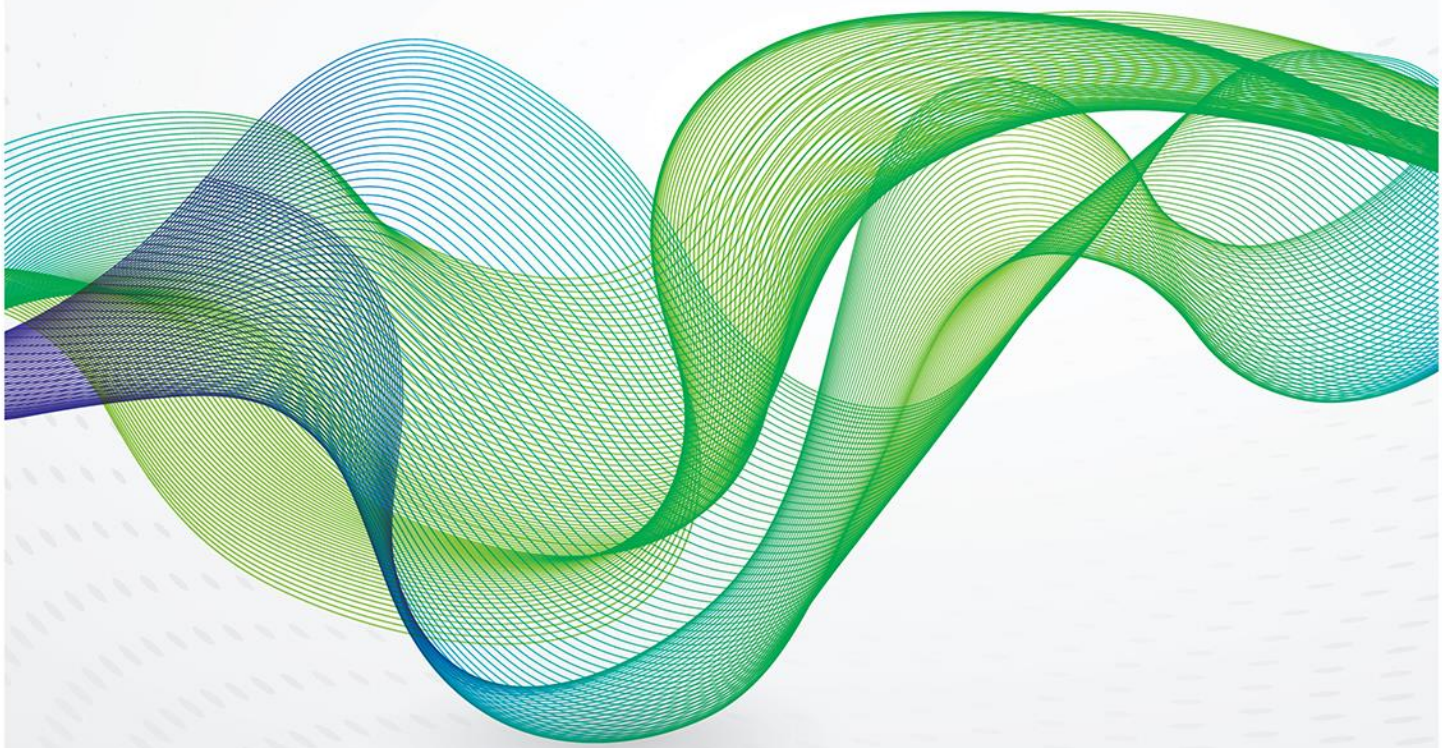
Norwegian Gas Exports: Assessment of Resources and Supply to 2035



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Abstract

Norwegian net gas production reached a record high of 122 bcm in 2017, comfortably exceeding the official projections of the Norwegian Petroleum Directorate (NPD) and confounding many industry observers who had in 2016 and 2017 been sceptical of the ability of the Norwegian Continental Shelf (NCS) to maintain production at 110-115 bcm. In January 2018, the NPD made significant upward revisions to its projections which now show output of 121-123 bcm pa from 2018 to 2022, declining to 112 bcm in 2025 and then stabilising at 90-92 bcm pa in 2030-35. This paper examines the reliability of the NPD's past projections and the plausibility of its updated projections based on published resource data, exploration activity, the capacity of onshore and offshore gas infrastructure, the demand for gas for improved oil recovery and published field development plans. It concludes that the recent revisions reflect a confident appraisal of the resource base and the numerous options for new gas development of existing fields and discoveries. The risk of failing to meet the updated projections to about 2027 appears to be low. Beyond 2027, the projections carry a progressively higher degree of geological, economic and political risk particularly in light of the recent lack of exploration success. By 2035, 30 bcm of the projected 90 bcm of annual gas production is expected to come from currently undiscovered resources. Meeting projected production between 2027 and 2035 will depend on maintaining the current level of exploration activity, on future commercial discoveries of gas and on continued improvement of recovery rates at producing fields. The visibility of future gas production has diminished in recent years because of the reduction in future delivery commitments in Statoil's gas sales portfolio. However, the reform of its gas sales since 2010 has conferred valuable new flexibility and discretion in future upstream investment decisions to develop and market NCS gas resources. The position of Norway as a reliable and competitive supplier of both contracted and flexible gas to NW Europe appears to be secure for the foreseeable future.

Units of Measurement

mcm	million cubic metres
mcm pa	million cubic metres per annum
bcm	billion cubic metres
bcm pa	billion cubic metres per annum
bbl	barrel (1 cubic metre = 6.29 barrels)
mboe	million barrels oil equivalent
mcm oe	million cubic metres oil equivalent
bcm oe	billion cubic metres oil equivalent
MJ/m^3	megajoules per cubic metre

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1. Introduction

The aim of this paper is to examine the updated projections of Norwegian natural gas production to 2035 published by the Norwegian Petroleum Directorate (NPD) and to assess their plausibility and the risks surrounding the projections. The paper considers the principles of resource management embedded in Norwegian petroleum law and regulation, the published gas resource data, exploration activity, the demand for gas for improved oil recovery, gas processing and transportation capacity, the marketing of Norwegian gas and operators' publicly stated field development plans.

After a short historical review of gas production in Section 2, the NPD's latest projections and the reliability of their past projections are discussed in Section 3 of this paper. Section 4 outlines the government's resource management policy and upstream regulation. The existing NCS gas resource base is considered in Section 5 and exploration policy in Section 6. Gas infrastructure capacity and operation are discussed in Section 7. Gas marketing and the reform of Statoil's sales contract portfolio are described in Section 8 and Section 9 sets out the main conclusions of the paper.

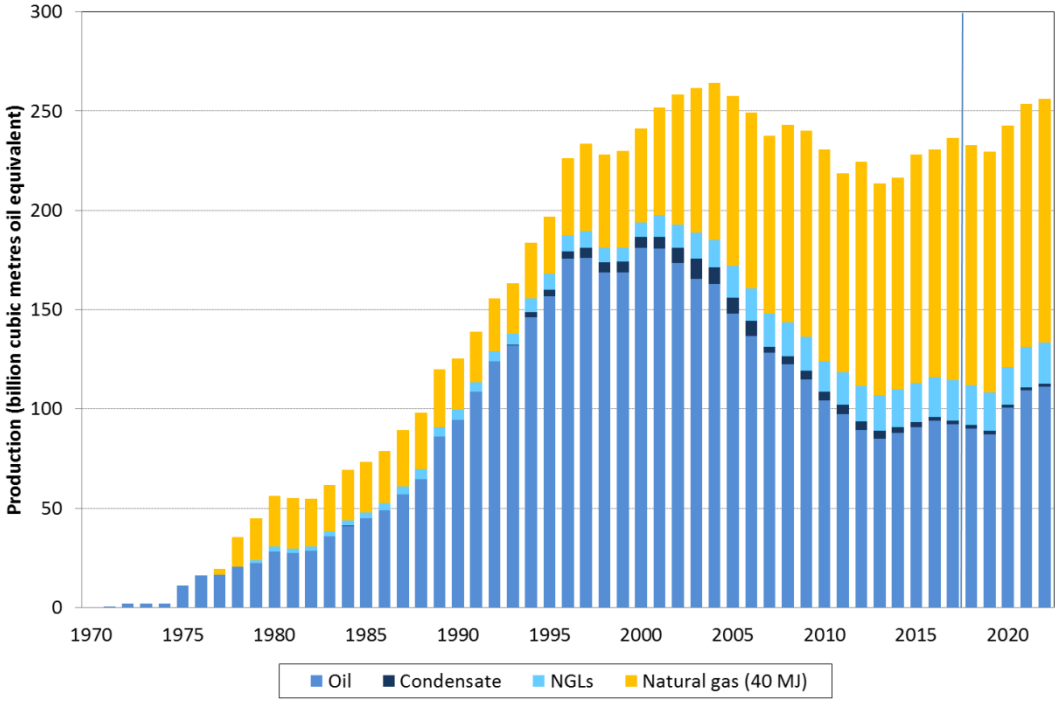
The focus of this paper is the gas resource base on the Norwegian Continental Shelf (NCS) and the influences on resource development and future gas supply, not on the demand for Norwegian gas. There is ample historical evidence that Norway is a highly competitive supplier of both contracted gas and flexible, uncontracted gas to the markets of NW Europe. This assessment was reinforced by the NCS supply response in 2017 to the continuing recovery in European gas demand, the restrictions on Groningen output and the loss of Rough storage capacity in the UK. We expect that existing and future investment will continue to ensure that Norway remains a competitive and reliable source of supply. We do not attempt to assess its competitive position in the long-running debate over competition between Russian pipeline gas and LNG as suppliers to European markets. Indeed, we believe any attempt to do so may yield misleading conclusions because of the emphasis on long-term value creation for Norwegian society in the management of NCS hydrocarbon resources and the co-dependence of gas supply and oil production in almost all areas of the NCS.

The paper draws exclusively on published information, principally the comprehensive statistical data published by the NPD and data released by operators. Although operating data on gas resource development are comprehensive, financial data on capital expenditure, exploration spending and development and operating costs are more limited and do not generally separate gas activities from oil activities. The gas-specific data is limited principally to gas price realisations, transfer prices and published gas processing and transportation tariffs. We have not attempted a comprehensive field-by-field analysis of current gas production operations or future developments.

2. Background: a short history of NCS gas development

The development of oil resources and gas resources on the NCS have followed very different paths since the first commercial hydrocarbon production began in 1971. In the early years of offshore activity, gas resource development was retarded by market and policy considerations. As Figure 1 shows, for the first twenty-five years, oil dominated new field development and NCS petroleum production. However, since 2000, when oil production reached its peak, gas output has risen strongly after this initial lag. Gas production began in 1977 at the Ekofisk and Frigg fields, underpinned by field depletion contracts signed with continental European and UK buyers respectively. The development of other gas resources was severely held back in the period before downstream market liberalisation by the need to search for European buyers willing to make long-term commitments, by the need to construct and finance new export pipeline infrastructure and by the government's prohibition of gas flaring offshore. The restraints on gas resource development were finally transformed by the discovery and appraisal of the giant Troll field in 1979-83 and the conclusion of new gas sales agreements on the continent between 1986 and 1990. Troll produced its first gas in 1996 and provided the secure basis for further gas resource development elsewhere on the NCS.

Figure 1: Norwegian Liquids and Gas Production 1970-2022



Source: 'Shelf in 2017', NPD January 2018

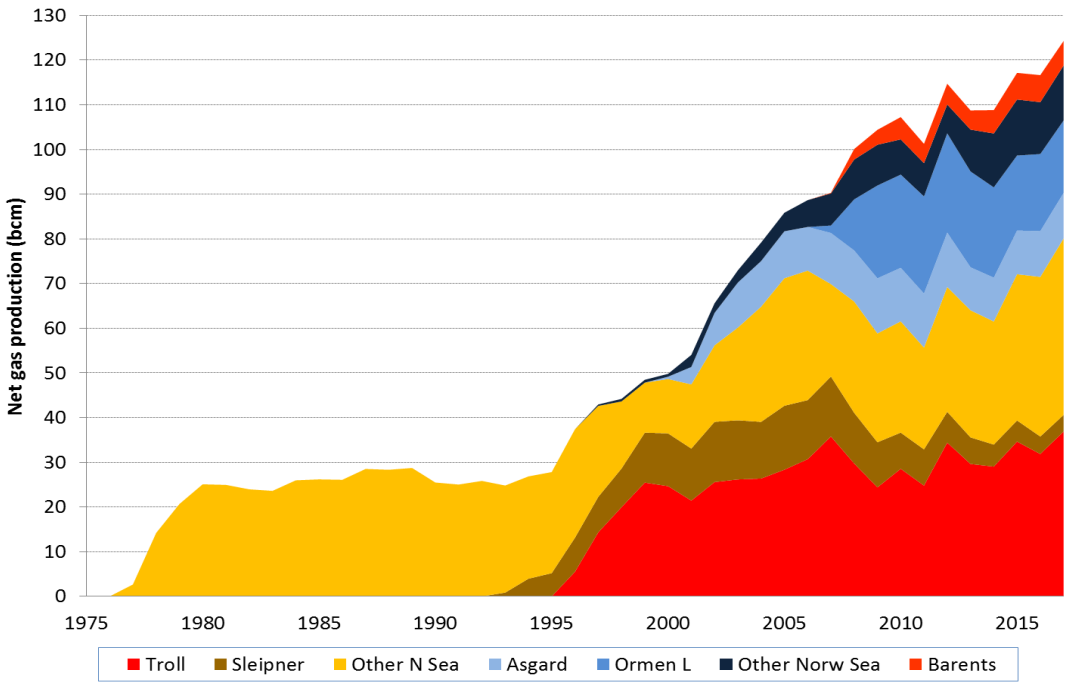
Between 1995 and 2005, dry gas production rose threefold from 29 bcm to 86 bcm as major new fields such as Troll, Sleipner and Åsgard were brought on stream to serve long-term volume contracts and to meet rising demand for uncontracted gas. These new fields were supplemented by rising associated gas from new oil fields, initially from the North Sea and later from the Norwegian Sea, as shown in Figure 2 below. When Troll reached initial plateau production of 25 bcm in 2000, it accounted for half of all NCS gas output. Since then, new discoveries and developments have progressively diminished its share of annual output even though it remains the key source of seasonal swing and flexibility on the NCS. Since 2005, gas production has continued to grow but rather more slowly, reaching a new peak in 2017 of 124.2 bcm (122 bcm at 40 MJ/m^3). Gas production was recorded from no fewer than 61 of the 85 hydrocarbon-producing fields in 2017, indicating a much larger and more diverse production base than ever before. According to the NPD's latest projections, output is now expected to be high and stable at 121-123 bcm pa until 2022 before a gradual decline to about 90 bcm pa between 2030 and 2035[1].

Since 2012, net gas production, expressed in energy equivalent terms, has represented about 50% of total petroleum production on the NCS. It has also become progressively more important in export revenues and the government's net cash flow from the oil and gas sector, especially in the period of lower oil prices in 2015-17. Since the peak in oil production, the share of export revenues derived from gas has risen steadily from 20% to almost 50% in 2015-17[2]. The government does not split its net cash flow from the NCS (NOK 180bn or $21.7 bn in 2017) between oil and gas[3]. However, we may reasonably deduce that the lower volatility of gas-related revenues may offer some advantages as far as government budget forecasting is concerned. Gas remains a lower-value commodity than oil,

[1] NPD press release and 'Shelf in 2017' presentation, 11 January 2018
[2] Statistics Norway 'Export Value of Petroleum Production 1971-2017', www.norskpetroleum.no
[3] Ministry of Finance 'Net Government Cash Flow from Petroleum Activities', www.norskpetroleum.no

realising delivered prices in energy equivalent terms of 50-70% of the value of crude oil, but upstream production costs, including pipeline transportation costs, are also generally lower, too. Although published data do not allow a definitive financial comparison, it is widely recognised that financial returns to typical gas projects on the NCS have in the past been lower than those for oil with a similar resource base. This has tended to reinforce the principle in NCS resource management to retain gas resources for improved oil recovery and to produce gas for sale later in the life of a field when the gas no longer has a higher value in oil recovery. In this way, the objective of maximising the economic value of the combined oil and gas resource base is more likely to be achieved in the long term.

Figure 2: NCS Net Gas Production 1975-2017 by Major Field and Region



Source: NPD Fact Pages field production data

There are very few fields on the NCS which produce only, or almost exclusively, dry unassociated gas, Ormen Lange (16 bcm in 2017) being the largest. Most saleable gas derives from fields which produce both liquids and gas. Discussion of Norwegian gas production tends to focus on the volume of net production of saleable dry gas. In 2016, the latest year for which full gas production data are currently available, this figure was reported by the NPD to be 116.6 bcm. It is sometimes not appreciated that gross production of wet gas, measured offshore before processing, was no less than 163.2 bcm[4]. The difference between the gross and net gas production figures is accounted for by gas re-injected into reservoirs, the extraction of NGLs at processing plants, fuel use and a small volume of authorised offshore flaring for safety reasons.

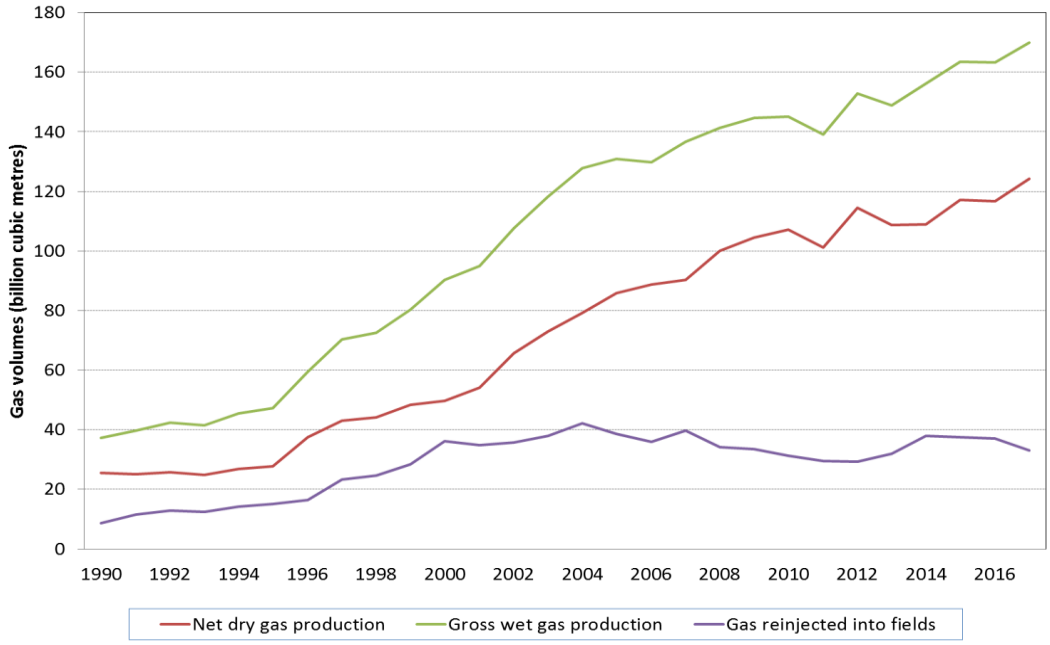
According to NPD data, re-injection of gas to maintain reservoir pressure and to improve oil recovery was 37.1 bcm in 2016. The Oseberg field accounted for 12.2 bcm of the gas re-injected and seven other oil-producing fields (Grane, Gullfaks, Skarv, Snorre, Troll, Visund and Åsgard) accounted for a further 20 bcm between them. In most instances, the gas is re-injected into the same reservoir from which it was extracted but in a small number of cases the re-injected gas is transported from an adjacent field before re-injection. In 2017, gross production of wet gas was an estimated 168 bcm and net

[4] NPD Diskos portal, Public Production Portal.

production of dry gas was 124 bcm[5]. An estimated 33.5 bcm of gas was reinjected into reservoirs, less than in 2016, thereby boosting saleable dry gas volumes in 2017.

As Figure 3 below shows, since 1999, the volume of gas re-injected has been consistently in the range 30-40 bcm each year. Since gas sales began in 1977, about 800 bcm of produced gas has been re-injected into producing reservoirs[6]. The scale of historical gas reinjection for improved oil recovery on the NCS is highly unusual among major producing provinces. The priority given for decades to optimal recovery of oil resources means that there is now a large reserve of relatively low-cost gas which will be available for production and sale in future when it no longer becomes economic to extract further oil. At this point, the accumulated gas cap may be blown down, making more gas available for sale.

Figure 3: NCS Gross and Net Gas Production and Gas Re-injected 1990-2017



Source: NPD database

The 50-year history of the NCS is marked by a gradual migration of activity northward from the shallow water North Sea (south of latitude 62^0 North) into the harsher conditions of the Norwegian Sea (62-68^0 North) and the Barents Sea (roughly 70-74^0 North). Today, the NCS includes both highly mature areas, such as the North Sea, and frontier areas, such as parts of the Barents Sea which have only recently been opened to exploration drilling. Acreage in the Norwegian Sea was opened in 1979 and the first production began in 1993. The first acreage in the Barents Sea was awarded in 1980 but it was not until 2007 that production began from the Snøhvit field. Given the remote location within the Arctic Circle, distant from the existing pipeline infrastructure, it was decided to develop Snøhvit to supply gas to a new onshore LNG plant at Melkøya. In 2013, the Storting approved the construction of the Polarled pipeline linking the northern Norwegian Sea to the existing onshore gas processing plant at Nyhamna. Polarled marks the largest addition to the export gas infrastructure since the construction of the Langeled pipeline in 2005-06 and marks an important step in the northward extension of the gas export pipeline network.

Certain areas of the NCS, notably around Lofoten, Vesteralen and Senja ('LoVeSe') and in the Barents Sea, remain closed to exploration for environmental reasons. Areas of the south-east Barents Sea were

[5] Author's estimate from available monthly data from NPD
[6] NPD field data on gas injection 1975-2014 and Diskos data 2015-17

opened in 2013 after agreement was reached with Russia over the maritime border but the northern part of the Barents Sea remains closed to exploration. The North Sea has remained the key hub of NCS oil and gas production and the location of the major gas processing and pipeline infrastructure which will serve the new wave of production from fields in the northern Norwegian Sea due to deliver gas through the Polarled pipeline from late 2018.

The technical and economic success of the offshore oil and gas industry in the last 50 years has transformed the domestic Norwegian economy and underpins the future of its distinctive social welfare model through the state's contributions to the Government Pension Fund or 'Oil Fund', the world's largest sovereign wealth fund now worth $1 trillion. Yet the domestic oil and gas industry has in recent years faced an acute domestic political challenge from advocates of tighter restrictions on offshore hydrocarbon activity for local environmental reasons and from climate change campaigners seeking to curb further offshore development. The result has been that coalition governments in Oslo are no longer able to promote the interests of the upstream industry and resource management without incurring some domestic political opposition[7].

The most recent elections to the Storting (Norwegian parliament) in September 2017 led to the formation of a centre-right coalition government comprising the Conservatives, the Progress Party and the centrist Liberal Party but it remains dependent on other parties for a parliamentary majority. The new coalition agreement, reached in January 2018, includes provisions which illustrate the current, more contentious political context for NCS operations. The agreement postpones the 25th licensing round, originally expected to begin in 2019, pending review and revision of the management plan for the Barents Sea and Lofoten. It also includes a clause preventing any opening of 'LoVeSe' to exploration before 2021. The major parties remain supportive of further offshore exploration and the oil and gas industry but, for the time being, parliamentary arithmetic is not favourable to the further extension of open areas on the NCS.

3. NPD's current gas production projections

The Norwegian Ministry of Petroleum and Energy (MPE) or the Norwegian Petroleum Directorate (NPD), responsible to the MPE, has published annual projections of gas production or gas sales from the NCS since at least 1981, soon after the beginning of the first commercial production from the Ekofisk field in 1977. The format, tenor and degree of detail in the projections carried in their annual publications have varied considerably over this period but the regularity of the published projections provides a useful record of the fluctuating official expectations for gas resource development, and the demand for Norwegian gas, over this 35-year period.

In the 1980s, the projections were largely single-point forecasts up to 15 or 20 years forward of the production from fields for which depletion contracts had been signed. After the signing of new long-term volume contracts in the period 1986-90, the NPD raised future production levels, extended the horizon of its projections and no longer allocated the gas sales to individual fields. By 2002, as sales continue to grow each year almost without interruption, the NPD had dropped the distinction between 'field contracts' and 'delivery contracts', preferring to distinguish between 'existing contracts' and 'possible new sales' as it emphasised the scope for further expansion of sales and production until at least 2010. In 2004, when production had risen above 70 bcm and future sales commitments were about 80 bcm pa, the NPD described annual sales of 120 bcm from 2010 onwards as a 'realistic scenario'[8].

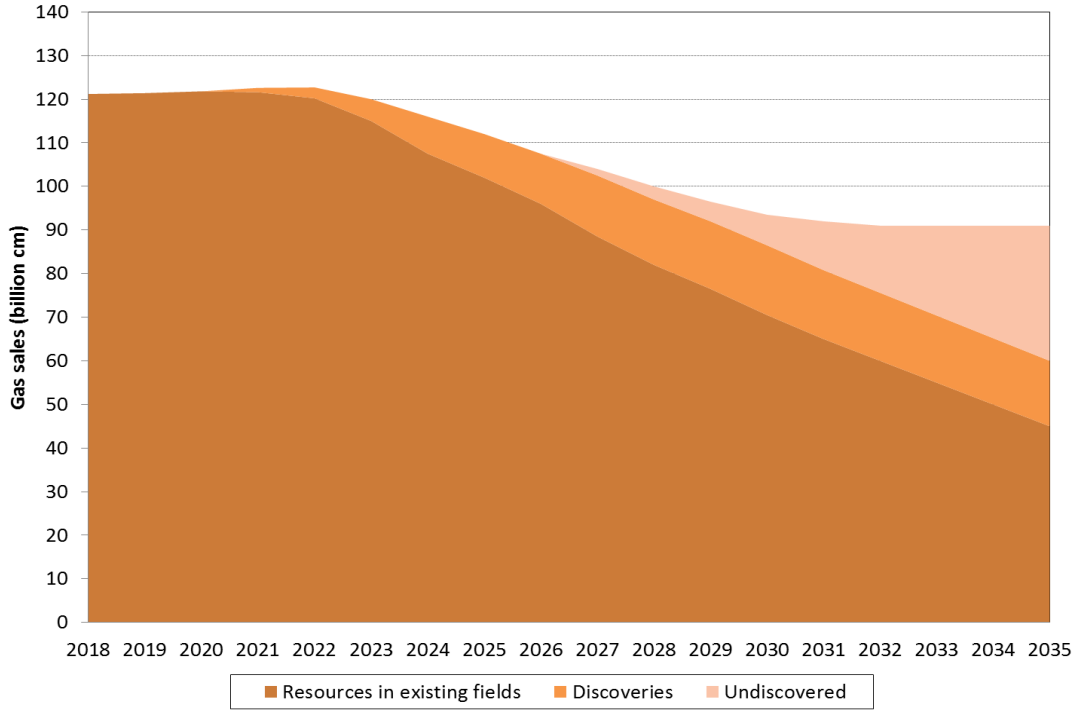
In 2007, growing optimism over European gas demand and future NCS developments led the NPD to publish an estimate of NCS sales by 2020 of 120-130 bcm pa but it sensibly qualified this figure by

[7] In November 2017, environmental organisations Greenpeace and 'Nature and Youth' took the government to court alleging that the award of acreage in the Barents Sea in the 23rd round was a breach of the constitution and unlawful. In January 2018, the Oslo court found in favour of the government that the awards were lawful.
[8] FACTS 2004, MPE and NPD p.37 available on NPD website

introducing a range of about +/- 10 bcm pa around the central projections. The following year, projected gas sales by 2020 were raised to 125-140 bcm[9]. This proved to be the high water mark in official expectations of future NCS gas sales. In response to the sharp contraction of gas demand in 2008-09 and the decision in 2007 not to approve expanded gas sales from the Troll field, the NPD downgraded its gas sales projections. Between 2011 and 2014, it projected NCS gas sales of 105-130 bcm in 2020 and 80-120 bcm in 2025 and emphasised the uncertainty over future gas production as continental term contracts were renegotiated in this period.

In addition to its regular long-term projections 15-20 years forward, since 2007 the NPD has included single-point projections of NCS gas sales for the next five years in its 'Shelf' presentation made each year in January. It is able to make such projections because it has privileged access to the gas production plans and performance of all NCS fields through regular data submissions from field and infrastructure operators. It chooses to do so in order to make the overall capability of the NCS transparent to market participants under assumptions of normal weather and normal offshore operations. In January 2018, the NPD published its updated projections for long-term gas sales to 2035 (Figure 4), and its most recent short-term projections to 2022 (Figure 5)[10]. Both sets of projections are expressed based on a standard energy content of 40 MJ/m^3. We discuss the two sets of projections in turn.

Figure 4: NPD 2018 Projection of Net Gas Production 2018-2035



Source: NPD, 2018 www.norskpetroleum.no

The longer-term projections to 2035 (Figure 4) represent P_{50} production estimates divided into three resource categories: resources in existing fields, resources in discoveries and undiscovered resources. They show a plateau in production of about 122 bcm pa from 2018 to 2022 and a progressive decline thereafter to about 90 bcm pa between 2030 and 2035. No projections are published for individual fields

[9] FACTS 2008, MPE and NPD p.50
[10] NPD Shelf in 2017, press release and presentation, 11 January 2018

or NCS areas. Gas from currently undiscovered resources makes a contribution to the profile from 2027. By 2035, undiscovered resources account for about 30 bcm of projected annual production.

The first observation to be made about these projections is that the economic assumptions behind them, such as oil and gas prices and capital and operating costs are not disclosed; in this regard, they are no different from any of the official long-term projections made in that last 35 years. The value of this approach is that it focuses on the resources base and not on the unpredictable fluctuations of prices and costs. The second observation is that, between 2007 and 2014, long-term projections of gas production and sales were expressed as a range in order to convey the uncertainty and the risks relating to the gas resource base and its economic development. In 2015, as the debate over the EU's energy and climate policy intensified, the MPE decided that Norway needed to emphasise its role as a secure, reliable long-term supplier of gas which, it argued, is an indispensable element of 'least-cost decarbonisation' in the EU. Apparently in an effort to establish Norway's capability in the eyes of EU policy-makers, in 2016 the NPD identified gas production separately from oil production, the range of uncertainty in future projections was replaced by a single-point figure and the horizon of the gas projections (but not oil) was extended to 2035. Although the single-point projections may have offered reassurance in some quarters, they have unfortunately removed the conception of risk and uncertainty which necessarily surrounds projections 15-20 years forward.

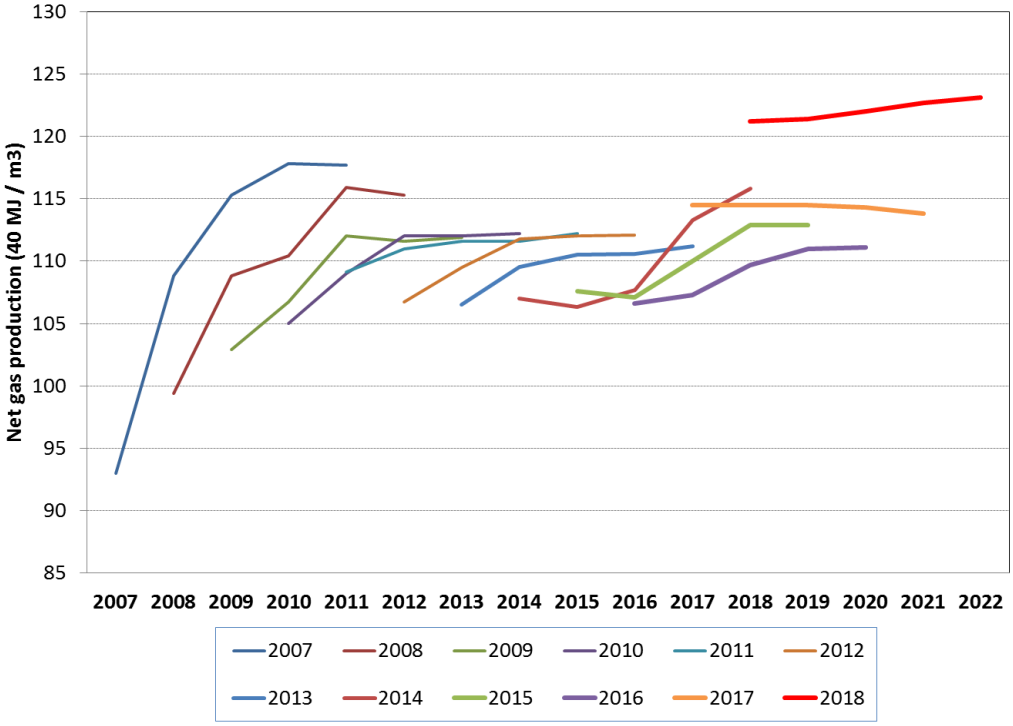
It is important to note two other significant features of the latest projections to 2035. Firstly, the lowest-risk resource category ('resources in fields') comprises not only reserves in fields in production and in development but also resources in fields which have not yet been approved and may not be commercial. Second, the highest-risk category of 'undiscovered resources' no longer includes gas expected to be produced from resources which lie in currently unopened areas of the NCS. In the past, projections 15-20 years forward have included gas from unopened areas. For example, in the government's last major White Paper on the industry, released in 2011, about half the expected gas production from undiscovered resources 20 years in the future (2030) had been assumed to come from unopened areas[11]. Since there is intense domestic debate about exploration activity in environmentally sensitive offshore areas, this change of methodology behind the projections has had the effect of reducing the degree of political risk associated with the projections for 2030 and 2035, leaving the principal risks as geological and economic.

Figure 5 shows the evolution of the short-term five-year projections between 2007 and 2018[12]. It shows clearly how the NPD significantly raised its projections of gas production in its latest annual presentation on January 2018, after record production of 122 bcm in 2017. This followed a more modest upgrade the previous year when five-year forward output was raised to 114-115 bcm pa after a decade of consistently projecting gas production in the range of 105-115 bcm pa. Output in the period 2018-2022 is now projected to be 121-123 bcm in each of the five years. In our view, the latest upward revisions are not simply a reaction to the record output of 2017 but reflect greater confidence within government and the industry about the performance of existing mature fields, the commissioning of the Aasta Hansteen field in late 2018 and the economic viability of future gas development projects, notably Troll Phase 3, which is now expected to request approval in 2018. The upward revisions may also reflect new, unpublished projections by the NPD of the demand for gas for offshore reinjection and greater confidence in the demand for Norwegian gas from European buyers in coming years after a third year of recovery. Once the final figures for reinjected gas by field in 2017 are available, it may be possible to judge whether the decline in gas reinjection at mature oil fields observed in 2017 is likely to mark the beginning of such a trend.

[11] 'An Industry for the Future – Norway's Petroleum Activities' Meld. St. 28 (2010-11) Report to the Storting (White Paper), June 2011

[12] NPD annual Shelf presentations and datasets 2007-18

Figure 5: NPD Five-Year Projections of Net Gas Production 2007-2018



Source: NPD annual Shelf presentations, 2007-2018

Although based essentially on the NPD's assessment of the resource base and investment plans, the accuracy of the latest projections will depend in part on the course of European gas demand in the next five years. Between 2007 and 2011, the NPD over-estimated outturn gas production in its short-term projections since, like all gas market analysts and forecasters, it failed to anticipate the full impact of the 2008-09 recession. Since 2012, it has become more cautious and more accurate in its projections but has tended to under-estimate outturn volumes. This trend continued in 2017 when output (122 bcm) far exceeded its projection (114.5 bcm) because of the way events at Groningen and the Rough storage site boosted demand for uncontracted Norwegian gas. In our view, there is little doubt that the NCS is capable of stabilising output at 120-125 bcma until 2023 provided that key infrastructure assets, notably the three major onshore processing plants, continue to perform reliably and gas demand in NW Europe does not suffer an unexpected contraction.

4. Petroleum resource management and regulation

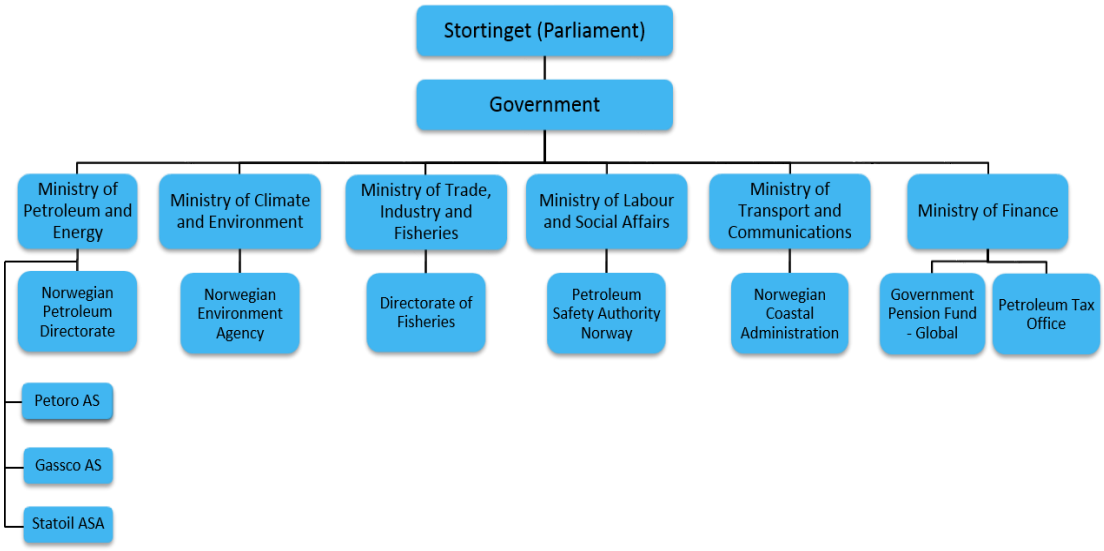
Since the 1960s, petroleum activity on the NCS has been marked by a high degree of direct and indirect state equity participation, active long-term resource management by the government in its capacity as regulator and a stable legal and fiscal framework governing offshore activity. In these respects, it stands in sharp contrast to the model of resource development pursued on the adjacent UK Continental Shelf. The State's Direct Financial Interest (SDFI) is managed by Petoro, a state-owned company which holds interests in licences but is not an operator. In addition, the state owns 67% of Statoil, the largest operator and producer on the NCS. The state's interest in both Petoro and Statoil are managed by the Ministry of Petroleum and Energy (MPE).

The Storting (Norwegian Parliament) sets the legislative framework for all petroleum activities and involves itself in approvals of all major field and infrastructure projects. According to the Petroleum Act 1996, the resources of the NCS are vested in the State and all licensed activity to exploit them is

required to ensure that the value created benefits Norwegian society as a whole[13]. The Act provides for the licensing system which governs all petroleum activity and makes the MPE responsible for resource management and supervision of almost all activities in the sector. Health and safety are the responsibility of the Petroleum Safety Authority (PSA) under the Ministry of Labour and taxation is a matter for the Petroleum Tax Office which is part of the Ministry of Finance.

The Norwegian Petroleum Directorate (NPD) is an agency subordinate to the MPE. The directorate plays a key role in petroleum resource management and serves as the main advisor to the MPE. It exercises administrative authority in relation to all exploration and production on the NCS, including powers to stipulate regulations and to make decisions in accordance with existing regulations. In short, the NPD plays a central role in the state's regulation of the NCS at every stage from seismic acquisition to decommissioning[14].

Figure 6: State Organisation of Upstream Petroleum Activities



Source: Norwegian Petroleum (MPE and NPD)

The abiding principle of resource management adopted in law and implemented by the NPD is to ensure that all development delivers the maximum possible social benefit for Norwegian society and the domestic economy *in the long-term*. In this respect, the NPD explicitly adopts a much lower discount rate than private investors, usually 7 per cent, in its economic appraisal of resource development options. It also incorporates in its appraisal economic costs and benefits which are normally excluded from the narrower financial calculation of private companies.

The authority of the MPE over gas resource development effectively begins when a licensee submits a Plan for Development and Operation (PDO) after a discovery is declared commercial or, in the case of infrastructure assets, when a Plan for Installation and Operation (PIO) is submitted. The MPE, advised by the NPD, decides whether conditions should accompany the approval of a PDO. A standard Joint Operating Agreement (JOA) between the companies awarded a production licence is also required by the MPE. This provides the foundation for the long-term plan for production from the field over its

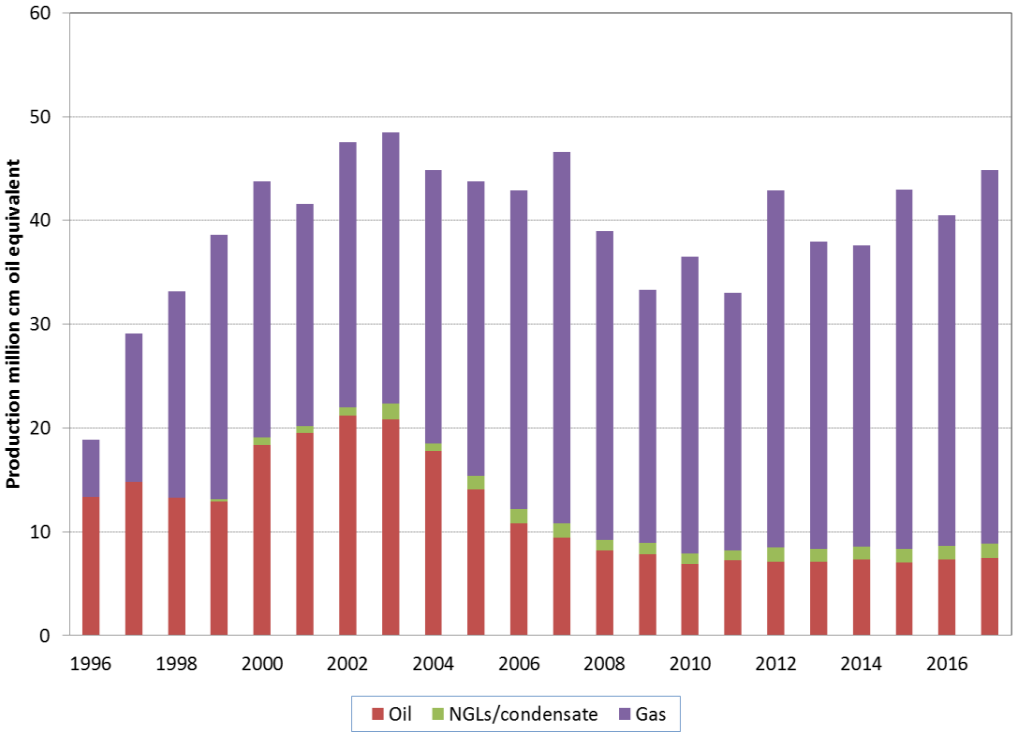
[13] 'Act 29 November 1996 No 72 relating to petroleum activities', subsequent amendments and all related regulations and guidelines are available on the NPD website.
[14] The responsibilities and activities of the NPD are summarised in a presentation 'Duties and Roles of the NPD' November 2017 available on the NPD website.

expected life. Where the field produces both oil and gas, the JOA will normally include a Gas Lifting and Balancing Agreement (GLBA) intended to regulate gas production to optimise liquids recovery.

Once a field is in production, the obligation of operators to comply with the Resource Management Regulations ensures that the NPD has a regular flow of data from operators through the submission of the Annual Status Report (ASR)[15] and the reporting to the annual Revised National Budget[16]. Each approved field has a permitted level of gas production each year. If an operator wishes to revise its annual permit, it must make an evidence-based submission to the NPD by the end of February for a decision to take effect by the beginning of the gas year on 1 October. These annual permitted volumes are not normally publicly disclosed but they form an important part of short-term gas supply regulation *for resource management purposes* for key swing fields like Troll and Oseberg and larger, less flexible fields such as Ormen Lange and Åsgard. For any field permit request, the recommendation of the NPD to the MPE will be based on the consistent principles of prudent resource management and long-term value creation based on detailed technical assessment and reservoir modelling. In summary, the NPD is well-placed to assess whether operators' production plans are consistent with long-term value creation *for the NCS as a whole*, not only for the individual license area, and it possesses the regulatory powers to ensure that operators follow its strict guidance on gas production and sales at every stage of the approvals process.

The NPD has earned an enviable reputation for technical competence and consistent application of the principles of long-term value creation in the management of NCS resources. It does not seek

Figure 7: Troll Output 1996-2017: Priority Given to Oil Recovery



Source: NPD FactPages field production database

[15] The Annual Status Report for all fields in production shall be submitted to the NPD by 1 November as required by section 47 of the Petroleum Regulations and section 29 of the Resource Management Regulations.
[16] Operators are required by section 50a of the Petroleum Regulations to submit data and forecasts for all fields and infrastructure to the NPD by 15 October to allow preparation of the Revised National Budget.

controversy but has sometimes found itself in public disagreement with operators or licensees over field development plans or proposed new investment. The development of the Troll field (Figure 7) is possibly the most notable case in which the NPD's insistence on retaining gas from the reservoir to maximise oil recovery has had a significant impact on the course of NCS gas production. Troll is unique, not only because of its size and strategic importance but also because the state has, for historical reasons, an unusually high equity share and financial exposure. It was the opposition of the NPD to the operator's plan to expand Troll gas production which ensured that, in 2007, oil recovery was given priority over increased gas sales for the following decade. Such public debate and disagreement are unusual but the case highlights the willingness of the NPD to defend staunchly its conception of long-term economic value and the priority it gives to improved oil recovery through gas injection. It has succinctly summarised its own approach as that of ensuring 'the production of the right hydrocarbon, at the right time, at the right rate and in the right order'.

Just as the NPD places great importance in PDO approvals on maximising the long-term value of oil recovery through pressure support by water or gas injection, so in recent years it has placed a new emphasis on improved oil recovery (IOR) at mature producing fields. It estimates that the average oil recovery factor on the NCS is currently about 47% but aims to raise this further through the application of new technology over the life of currently producing fields[17]. The NPD cites the Oseberg field, operated by Statoil, as perhaps the best example on the NCS of successful IOR using gas injection. Since oil production began at Oseberg in 1988, about 220 bcm of gas from the Oseberg and Troll fields have been injected into the reservoir, yielding an incremental 400 million barrels of recoverable oil[18]. The early adoption of gas injection at Statfjord and Oseberg for improved oil recovery has been repeated at many other oil fields such as Gullfaks, Visund, Snorre, Åsgard, Grane and Tyrihans. By 2016, gas was re-injected at no less than 24 oil-producing fields on the NCS. We expect the NPD's emphasis on gas injection for IOR will continue in the coming years. However, the age profile of mature oil-producing fields developed in the 1980s and 1990s suggests that total gas injection will begin to decline in the next 5-10 years as these fields reach the end of their economic oil-producing life, freeing up more gas for sale as the accumulated gas caps are blown down.

5. Gas resource and reserve base

The NPD estimates that, at the end of 2017, total ultimately recoverable petroleum resources on the NCS were 15.6 billion cubic metres oil equivalent (bcm oe), or 98 billion barrels oil equivalent [19]. Of this figure, 45% had already been produced, leaving remaining resources of 8.5 bcm oe or 54 billion barrels oil equivalent (Figure 8); these remaining resources comprise reserves, contingent resources and undiscovered resources. The range of uncertainty surrounding this central estimate is considerable, reflecting geological, technical and economic risks. Around the expected figure of 8.5 bcm oe, the NPD has a range of 6.7-10.9 bcm oe, the lower and upper limits of which correspond to the P_{90} and P_{10} resource estimates. Gas accounts for 4.2 bcm oe or 49% of the central resource estimate of 8.5 bcm oe. Undiscovered resources, including resources in areas of the NCS which are not currently open to hydrocarbon exploration and production, account for 44% of total remaining gas resources.

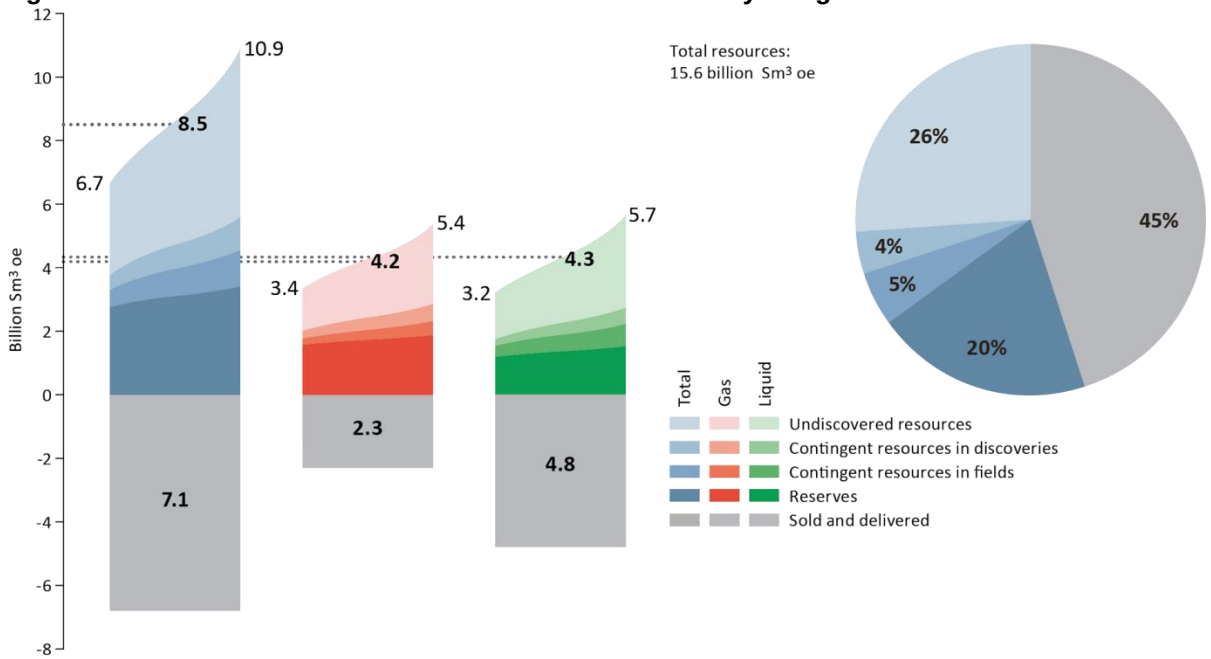
The most recent estimates mark a significant 15% increase in total remaining resources on the NCS between end-2016 (7.4 bcm oe) and end-2017 (8.5 bcm oe) following the mapping in 2016-17 of the north-east Barents Sea which is not yet open for exploration. Much of the 170,000 km^2 mapped was in the area previously disputed by Norway and Russia before they reached agreement on the maritime border in 2011. Undiscovered resources of both oil and gas were materially increased in 2017 by 21%

[17] 'Effective resource management in mature areas', Norwegian Petroleum, 2017
[18] 'IOR prize awarded to Statoil for subsea work on the Oseberg field', NPD 28 August 2012
[19] NPD Resource accounts at 31 December 2017, 27 Feb 2018

and 9% respectively. Almost half (47%) of the current estimated NCS remaining resource base is now undiscovered or 'unproven'.

The NPD's current resource classification system was introduced in 2001 to ensure that it was consistent with other international sources such as the Society of Petroleum Engineers (SPE) and the United Nations Framework Classification system. 'Reserves' are recoverable volumes for which a development decision has been made. This includes both resources for which a Plan for Development and Operation (PDO) has been approved and resources which licensees have decided to produce but for which they have not obtained the necessary consents. 'Contingent resources in discoveries and fields' are resources which are deemed commercially recoverable but for which no production decision has been made. This category includes resources expected through improved recovery techniques but excludes non-commercial or technical resources. Typically, contingent resources are transferred to the reserves category as they mature and licensees secure an approved PDO. 'Undiscovered resources' comprise oil and gas that is probably in place, based on seismic and geological data, but have not yet been confirmed through drilling. These yet-to-find resources include some resources in areas of the NCS which are not yet open for hydrocarbon exploration. Reserves and contingent resources are updated by the NPD each year; undiscovered resources are reviewed and revised every two years, most recently in 2017.

Figure 8: Total NCS Oil and Gas Resources and Uncertainty Range as at 31 Dec 2017



Source: NPD Resource Accounts at 31 December 2017

Since 2003, total recoverable hydrocarbon resources have risen progressively, notably between 2010 and 2013 following the discovery of the Johan Sverdrup and Johan Castberg oil fields, and in 2017 as resources in the north-east Barents Sea were incorporated into the aggregate NCS figure for the first time. However, the rate of new resource additions through exploration, field extensions and improved recovery has not kept pace with production rates. Consequently, *remaining* recoverable resources have shown a net decline since 2003, despite net additions in years such as 2013 and 2017 when undiscovered resources were significantly increased. Remaining oil resources have shown a modest net increase between 2003 and 2017 whereas remaining gas resources have recorded a 17% net decline to 4,203 bcm in 2017 in the absence of significant discoveries.

There are significant differences in the maturity, risk profile and concentration of oil resources and gas resources on the NCS. First, the gas resource base is substantially less mature and less developed than the oil resources (crude oil, condensate and NGLs). Gas accounts for just 33% of historical production between 1971 and 2017 but 49% of total remaining recoverable resources and 56% of total remaining reserves in fields.

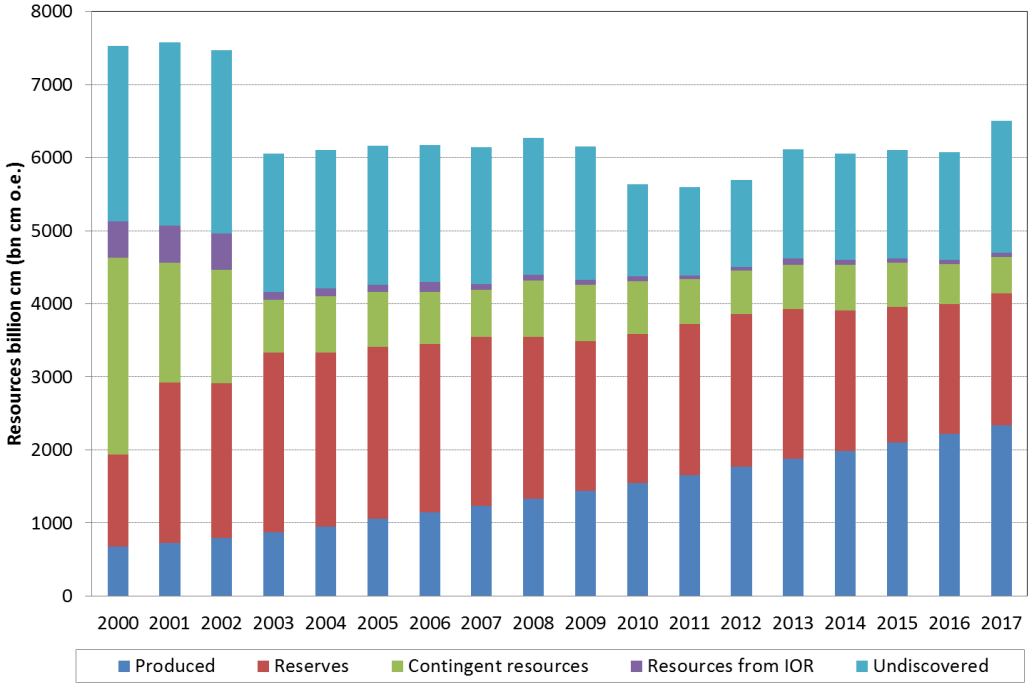
Secondly, the degree of risk associated with the central estimates of the gas resource base appears to be lower than the risk associated to the oil resource base, assuming a consistent approach to risk assessment by the NPD. The resources identified as reserves (categories 1-3 in the NPD classification) account for 41% of the remaining gas resource base but only 32% in oil. It should be said that this disparity may narrow in the next few years as the approval of further phases of development of Johan Sverdrup allows the upgrading of contingent oil resources to reserves, as has occurred in the past with other major projects. The lower risk associated with the gas resource base is, in part, a corollary of the extensive reinjection of gas into oil fields since 1976. Over the last 40 years, about 800 bcm of gas has been produced and then re-injected, principally to raise oil recovery rates. Not all this re-injected gas will be economically recoverable in the future but it provides a relatively secure store of value in long-term resource management and a source of potential new gas production in future years.

The third feature of the gas resource picture is the high degree of concentration of gas reserves and resources in the giant Troll field. Troll was discovered in 1979 and began producing gas in 1996. The total recoverable reserves of gas are estimated today at 1,433 bcm, more than double the estimate made in 2000 and four times the estimate made at the time of discovery. At the end of 2017, remaining gas reserves in Troll were estimated at 823 bcm which represents almost half (48%) the total remaining gas reserves on the NCS (1,729 bcm). The dominance of Troll in the gas reserve base has always presented a particular twofold challenge for the government: balancing the recovery of Troll oil against expansion of Troll gas exports and, secondly, preventing Troll production from 'crowding out' or holding back gas resource investment in other areas of the NCS.

In 2014, the NPD adopted a new target, to increase oil reserves on the NCS between 2014 and 2023 by 1.2 bcm (7.5 billion bbl)[20]. There is no such target to increase gas reserves. An earlier target set in 2005 to increase oil reserves by 800 mmcm (5 bn bbl) by 2015 was narrowly missed[21]. However, undeterred, the NPD set a new target for oil reserve growth in anticipation of reserve additions as successive stages of Johan Sverdrup are approved. The setting of a target for oil reserve growth, but not for gas, reflects not only the lack of sizeable gas discoveries in the last 15 years but also the fundamental difference between the perceived value of oil and gas on the NCS. Since oil resources are deemed to be of higher economic value to Norwegian society, oil recovery has remained the priority of resource management. A key issue for future gas production and exports after about 2025 is whether the demand for gas for injection to promote oil recovery at the new generation of oil fields will offset what is expected to be a decline in demand at oil fields already in production. It is unlikely that a clearer picture will emerge until Statoil has some experience of Johan Sverdrup in its production phase. The first phase is due to begin production in late 2019.

[20] The NPD confirmed in its Shelf presentation in January 2018 that it is currently on track to meet this target by 2023.
[21] 'Evaluation of reserve growth for oil 2005-14', NPD, June 2015

Figure 9: Evolution of NCS Gas Resource Base 2000-2017



Source: NPD Annual Resource Accounts 2000-17

Figure 9 shows the progression of the NPD's published gas resource data from 2000 to 2017. The significant upgrade to undiscovered resources in the Barents Sea in the 2017 figures was signalled by the NPD in early 2017[22]. The sharp downward adjustment in 2003 represents a significant revision of the methodology which led to a reduction in contingent and undiscovered resources but an increase in reported gas reserves. Since 2003, the methodology and classification system have been unchanged. The NPD does not disclose its economic assumptions, such as gas prices and capital and operating costs, but bases its assessments on annual submissions of data by licensees, as required by the Petroleum Regulations. The ultimately recoverable resource base has remained fairly stable since 2003 at close to 6,000 bcm despite some variation in the assessment of the undiscovered volumes from open and unopened area of the NCS. However, remaining resources have fallen steadily from 5,088 bcm in 2003 to 4,203 bcm in 2017 and remaining reserves have declined at a slightly faster rate to 1,729 bcm in 2017.

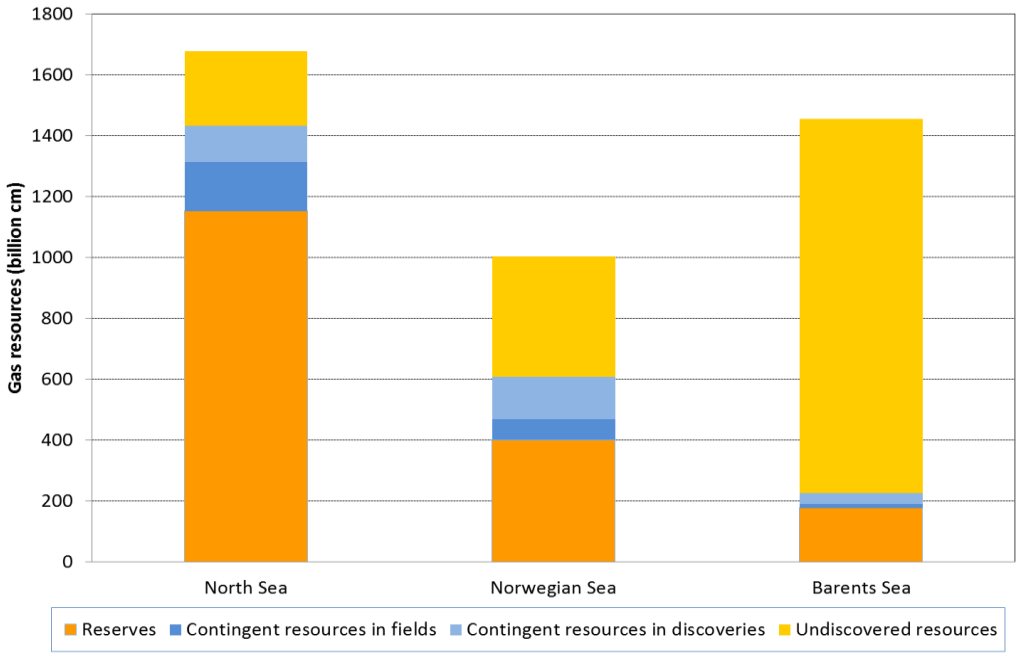
Unlike oil, there have been very few large discoveries of gas on the NCS in the last 15 years. The largest gas discovery since 2003 was of Linnorm in the Norwegian Sea with 24.9 bcm of recoverable resources but the field has not yet proceeded to development, unlike Aasta Hansteen (45.5 bcm) discovered in 1997 and Dvalin (18.8 bcm) discovered in 2010.

In presenting its resource data, the NPD divides the NCS into three areas: the North Sea, the Norwegian Sea and the Barents Sea. These areas exclude a large part of the NCS which extends north into the Arctic Sea, north of Svalbard, and west to the median line in the north Atlantic. Parts of each of the North Sea, Norwegian Sea and Barents Sea have special restrictions on hydrocarbon extraction for local environmental reasons. The area between the Norwegian and Barents Sea, around Lofoten, Vesteralen and Senja ('LoVeSe') is currently closed to hydrocarbon exploration but has been the subject of seismic surveys and scientific drilling in the past. In 2010, the NPD published a central estimate of

[22] 'Doubling the resource estimate for the Barents Sea', NPD, 25 April 2017

recoverable resources of 200 mcm oil equivalent in the waters off Lofoten based on seismic surveys in 2007-09[23]. However, the Storting subsequently decided to uphold the existing ban on exploration drilling even in the most prospective Nordland VI area. Under the new coalition government agreement of January 2018, the LoVeSe area will remain closed until 2021 and the 25th licensing round, which was expected to include some less mature areas of the Barents Sea, will be postponed pending a government review. The issue of exploration drilling in environmentally sensitive areas of the NCS remains highly topical amid reports that a consortium of companies may request approval to drill an exploration well at the limits of the unopened Lofoten area[24].

Figure 10: Distribution of NCS Remaining Gas Resources at End of 2017



Source: NPD Resource Accounts 2017

The geographical distribution of NCS gas resources is shown in Figure 10. Unsurprisingly, the picture it presents reflects the difference in the maturity of the three major regions. The North Sea, which includes the giant Troll field, accounts for over half (53%) of total recoverable gas resources of 6,544 bcm and more than two thirds (67%) of total gas reserves of 1,729 bcm. In the last decade, gas reserves *and* resources in both the North Sea and Norwegian Sea have been in decline but in the Barents Sea they have increased slightly from a very low base. At present, the only gas production in the Barents Sea is from the cluster of structures within the Snøhvit field feeding the LNG plant at Melkøya. According to NPD data, the Barents Sea is still one of great gas potential. Indeed, more than 80% of its estimated gas resource base of 1,230 bcm is undiscovered gas. As Figure 10 illustrates, the Barents Sea also accounts for almost two thirds of total undiscovered gas on the NCS. In the absence of new large gas discoveries elsewhere, converting some of this huge potential to contingent resources, and then to reserves, promises to be critical for slowing the rate of NCS production decline after 2025 as the reserve base in the more mature North Sea is further depleted.

[23] 'Petroleum resources in the sea areas off Lofoten, Vesteralen and Senja', NPD, June 2010
[24] 'Quartet sets sights on controversial Norwegian well' Upstream, 2 February 2018

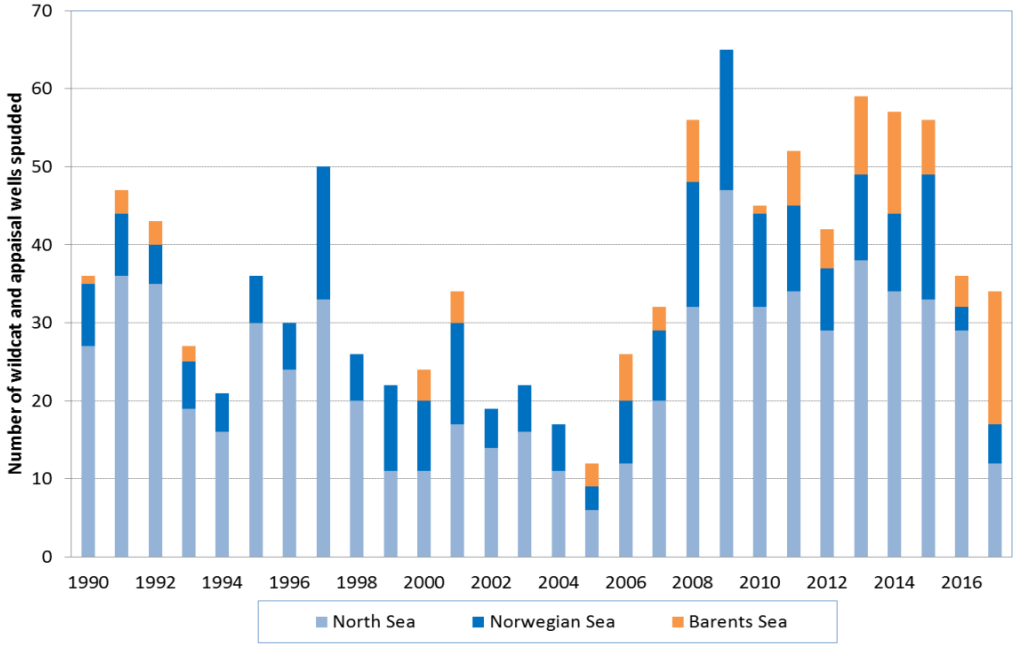
6. Exploration policy and activity

Since 2005, the Norwegian government has pursued an active licensing and exploration policy designed to attract private investors to discover and to develop the estimated 2,870 mcm oe of undiscovered oil and gas resources on the NCS. The licensing system consists of two types of rounds: the Awards in Pre-defined Areas (APA) in mature areas of the NCS and numbered licensing rounds in less mature areas where geological knowledge and existing infrastructure are more limited. Although the processes followed by the two types of rounds are different, all licence awards are decided by the MPE advised by the NPD. In recent years, APAs have been launched every year by the MPE and numbered licensing rounds in less mature area have taken place every two years. The APA round is designed to promote exploration in all mature acreage and to ensure existing infrastructure is not abandoned before all adjacent resources have been proven. The numbered rounds aim to achieve step-by-step exploration, especially in frontier areas of the Barents Sea.

The extent of interest in NCS exploration shown by exploration companies attests to the success of the government's policy in recent years even though the results of exploration drilling have been somewhat disappointing since 2010. In particular, the government has succeeded in widening the number and range of companies making exploration commitments despite the progressive decline in the expected discovery size in mature and semi-mature areas. Between 2011 and 2017, the average discovery size on NCS was about 7 mcm oe or 45 mboe[25].

The latest APA round (APA 2017) led to a record of 75 production licences being awarded in January 2018 to 34 different companies with work commitments in all three NCS areas[26]. Ten new production licences were awarded in 2016 in the 23rd licensing round including, for the first time, blocks in the south-east Barents Sea, the area formerly disputed by Norway and Russia. The 24th round launched in June 2016 also focused on the Barents Sea; the final awards are expected in mid-2018.

Figure 11: Exploration Drilling Activity on NCS by Region 1990-2017



Source: NPD Fact Pages

[25] 'Shelf in 2017' presentation, NPD, 11 January 2018
[26] MPE press release on APA 2017, 16 January 2018

Figure 11 illustrates the trends in exploration activity on the NCS since 1990: the strong recovery after 2005 in the number of exploration wells drilled, the shift in activity towards the Barents Sea since 2010 and the contraction of activity after the oil price collapse in 2014-15. The wells drilled comprise both wildcat wells and appraisal wells. In 2017, half the 34 exploration wells drilled were in the Barents Sea but the results were disappointing for almost all the companies involved. Exploration spending and activity is expected to remain at a similar level in 2018.

The NCS is sometimes described as a high-tax region for oil and gas production because of the headline marginal tax rate of 78%, before a deduction ('uplift') of up to 21.6% based on investment spending. However, in one important respect, NCS taxation is extremely favourable to offshore investors in that it offers immediate reimbursement of the tax costs of unsuccessful exploration[27]. Indeed, the dramatic increase in exploration drilling between 2005 and 2009 owes much to the introduction of the reimbursement option as an alternative to carrying the losses forward. This had the immediate effect of making NCS exploration very attractive for new entrants, unlike the more mature UK Continental Shelf where no such fiscal incentive exists. The reimbursement system has its domestic critics but there is little doubt that it has underpinned exploration drilling on the NCS for the last decade.

Exploration success is inherently unpredictable and episodic. In the 28 years between 1990 and 2017, the increase in oil and gas resources (2,900 mcm oe.) is dominated by the discovery of the Ormen Lange field in 1997 and Johan Sverdrup in 2010[28]. NPD aggregate data do not separate oil and gas resource additions from exploration. Over the entire period, the total additional oil and gas resources attributed by the NPD to exploration drilling amounted to less than 50% of total production (6,000 mcm oe) in that period. This rudimentary volumetric measure of the contribution from exploration does not of course indicate the economic value of such exploration. In its own study of the full-cycle profitability of NCS exploration published in 2016, the NPD estimated that exploration between 2000 and 2014 had contributed incremental net present value of almost NOK 500 billion, assuming a long-term real oil price of $90/bbl, a gas price of NOK 2/m^3 and a 7 per cent discount rate[29]. Johan Sverdrup accounted for about half the incremental NPV. In its most recent presentation, the NPD estimated that exploration between 2007 and 2016 had delivered a net present value of about NOK 450 million assuming a discount rate of 7 per cent but the value created was heavily concentrated in the North Sea and the Johan Sverdrup discovery[30].

The NPD acknowledges the inherent uncertainty of such estimates of the financial value of exploration, the acute sensitivity to underlying assumptions and the dependence on occasional large discoveries to remunerate exploration campaigns over long periods. There have been long periods in the past with very little exploration success, most notably the decade 1998-2007 but this has not diminished investor interest. Despite disappointing exploration results in 2015-17, when barely 100 mcm oe has been added to the resource base through exploration, the industry continues to demonstrate sustained interest in exploration on the NCS and the government remains committed to offering and awarding new acreage to develop the resource base.

7. Gas processing and transportation infrastructure

Since the mid-1980s, the state has viewed the rational development and efficient use of the gas processing and transport system as an essential element of its petroleum resource management and long-term value creation for Norwegian society. The consistent policy objectives of state regulation have been to ensure efficient operation of existing infrastructure and that profits are generated first and foremost in upstream production and not in gas processing or transportation. Accordingly, the state has

[27] 'The Petroleum Tax System', Norwegian Petroleum, May 2017
[28] 'Exploration Activity': Gross resource growth 1990-2016, NPD, February 2017
[29] Full-cycle profitability of exploration, Resource Report 2016, NPD.
[30] 'Shelf in 2017' presentation, NPD, 11 January 2018

regulated access to infrastructure and determined gas tariffs to permit a 'reasonable profit' of a 7 per cent pre-tax real rate of return on invested capital, leaving returns to upstream investors unregulated. Since 2003, gas tariffs have been set by the MPE in separate Tariff Regulations, as stipulated in the Petroleum Act and the Petroleum Regulations. New regulations governing third party access to all infrastructure designed to encourage more exploration and production of gas came into force in 2006. This regulated third-party access (TPA) regime has been particularly important in mature areas of the NCS in encouraging commercial agreement between infrastructure owners and operators and in successfully promoting new field tie-ins. In particular, the rise in North Sea gas production to a new record in 2017 (79 bcm) provides strong evidence of the success of the TPA regime in ensuring efficient access to existing gas processing and transportation capacity.

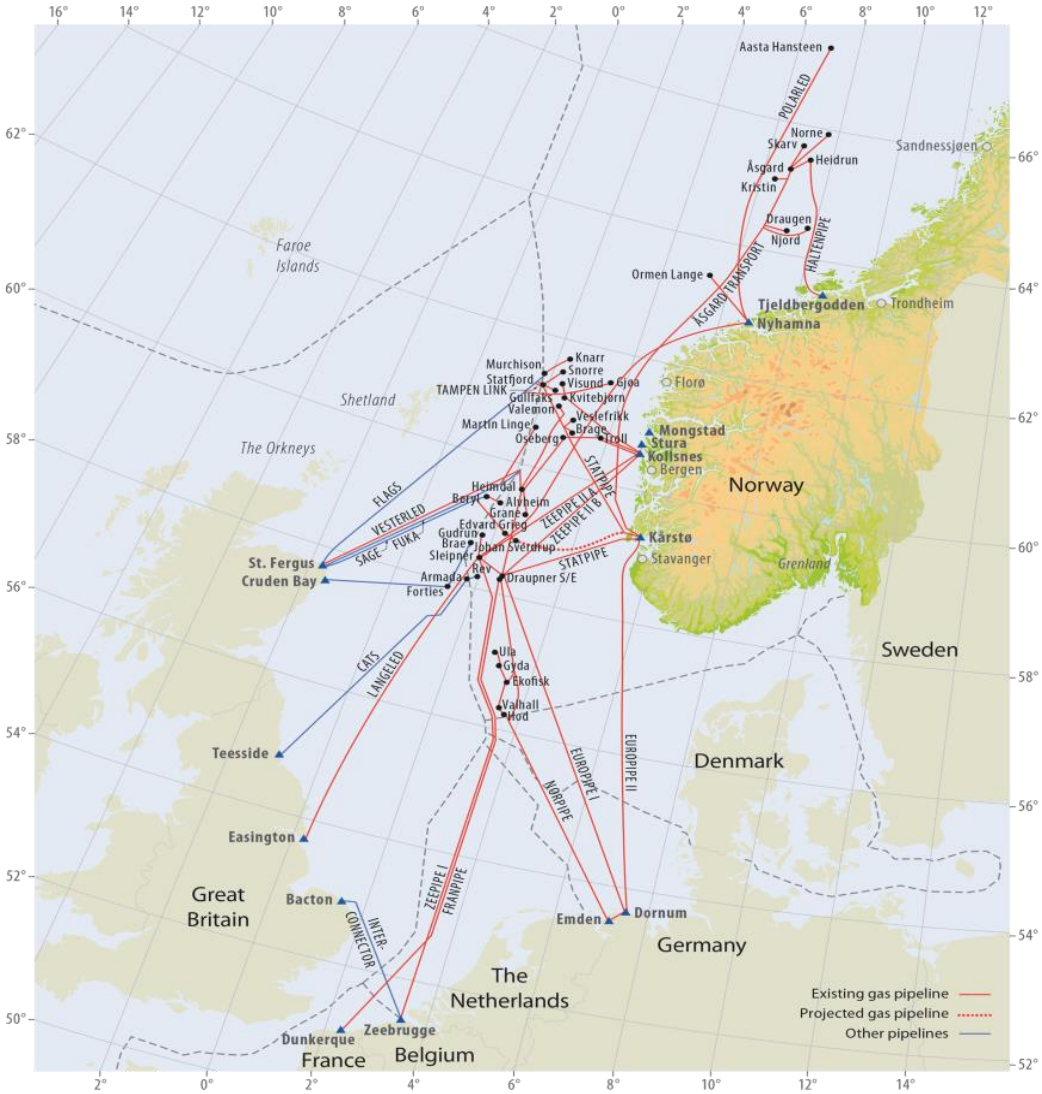
Almost all gas exported by pipeline from the NCS is transported through the offshore pipeline network owned by Gassled and operated by Gassco. In 2017, Gassco transported 117.4 bcm of gas to receiving terminals in the UK, Germany, Belgium and France[31]. Gassco was created in a major reform in 2001 as a wholly state-owned company and independent operator to ensure efficient operation of infrastructure under common ownership and non-discriminatory third party access. Access to gas processing and transportation capacity at reasonable cost was seen as a critical issue for many existing and prospective oil and gas developments. Since 2001, Gassco has gradually assumed operatorship of pipeline and processing facilities previously owned and operated by producing companies, a transfer of responsibility usually anticipated in the terms of the original PDO or PIO.

Gassled is a non-operating joint venture, established in 2003 through the merger of several separate transport systems, which owns most of the offshore gas infrastructure on the NCS. Its assets comprise processing facilities, offshore platforms, pipelines and onshore receiving terminals abroad. Gassled was originally owned by Petoro and many of the larger gas producers but in 2011 and 2012 most producers sold their stakes to financial investors attracted by the limited political risk and stable, regulated returns. Petoro is now the largest shareholder with 46.7% of the equity. Statoil retains a small (5%) equity holding, ensuring that the state retains effective control of the joint venture. The remaining equity is held by a number of infrastructure investors. Gassled's financial returns as a natural monopoly are regulated by the government through tariffs which are designed to deliver a 7% pre-tax real rate of return.

Gassco plays a number of distinct roles. It operates both the existing Gassled-owned assets under an agreement with Gassled, and other assets, notably Nyhamna and Polarled, which are still owned separately by producer-led joint ventures. Statoil and Shell provide technical services to Gassco at onshore processing plants at Kårstø, Kollsnes and Nyhamna. Gassco also administers the sale of the capacity to shippers, manages the gas flows through the network to minimise operating costs and undertakes a key role in assessing investment in new processing and transportation capacity. The pipeline and processing assets it operates are divided into at least 16 areas for which cost-based tariffs are published and regularly revised. Area D includes all the pipeline capacity delivering gas to terminals on the continent and in the UK, excluding only the Tampen Link volumes delivered via the FLAGS pipeline to St Fergus. The newest assets to be incorporated into the Gassco-operated system are the Nyhamna onshore gas processing plant (Area P), formerly operated by Shell, and the new Polarled pipeline (Area O) which will transport the first gas from Aasta Hansteen to Nyhamna in late 2018.

[31] 'Clear record set for Norwegian gas exports', Gassco press release, 11 January 2018

Figure 12: NCS Gas Export Pipeline Network

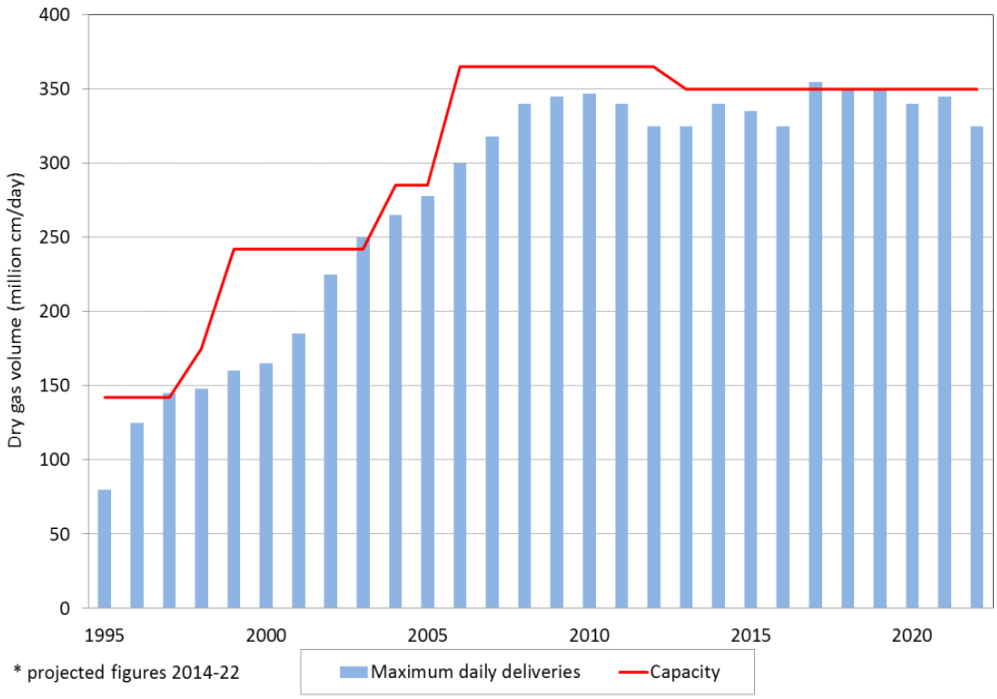


Source: NPD

In this open access infrastructure regime, NCS gas producers or their shippers must ensure that they hold capacity, acquired in the primary or secondary capacity market, to flow gas from the point of production through offshore pipelines to processing plants and then via Area D to an entry terminal on the continent or in the UK. The regime appears to have functioned well in facilitating market access for gas producers at reasonable cost and in operating assets efficiently to minimise costs and capacity redundancy. The Gassco system is highly reliable[32] and offers shippers a degree of flexibility in where they market their gas and allows them opportunities to optimise their daily and within-day trading.

[32] Gassco reports that on average in 2015-17 it met 99.5% of shippers' nominations in Area D and that 99.9% of its deliveries were within its contractual gas quality specifications, Gassco key figures.

Figure 13: Gassled Area D Maximum Deliveries and Capacity 1995-2022



Source: Gassco

Since 2013, the capacity of the Gassco system in Area D has been rated at 350 mcm/day (120 bcma), as shown in Figure 13. Actual deliveries have exceeded this figure on peak demand days in 2015-17 with growing frequency, reaching a peak of 376 mcm/day in 2016. Gassco has achieved this increasing use of existing infrastructure, without an erosion of operational reliability, by relieving minor transport bottlenecks and by expanding onshore processing capacity, most recently in 2016 at Kårstø. The sharp increase in Gassco throughput in 2017 to a record 117.4 bcm effectively means that the processing and transport system is operating at or close to full capacity more often in the gas year. As capacity utilisation on main export pipelines has increased, it is expected that gas trading flexibility has been more often constrained, if only temporarily. The recent upward revision of the NPD production forecast to 122 bcma until 2022 raises the question of the adequacy of existing Gassco-operated capacity, especially in the North Sea and Area D, after the commissioning of Aasta Hansteen in 2018-19 and a prospective Troll Phase 3 start-up by 2022.

Gassco has no publicly stated plans to expand Area D pipeline export capacity above 350 mcm/d. However, it is involved in investigating the viability of the proposed Baltic Pipe gas pipeline to take NCS gas from Europipe 2 to Denmark and on to Poland[33]. If the project is realised as currently conceived, the new line would increase the export capacity on Europipe 2 from the Kårstø processing plant to Dornum/Emden.

Gassco's gross tariff revenue in 2016 of NOK 27.4 bn indicates an average tariff for processing and transportation of about NOK 0.25/m^3 or approximately \$0.80/m BTU[34]. There is a wide variation in total costs (NOK 0.10-0.50/m^3) depending on gas quality, the number of tariff areas through which gas is deemed to pass and the capital costs associated with each area. Although NCS wellhead production costs may not be able to match those of some other major suppliers to Europe, the cost of delivering

[33] 'Baltic Pipe gas delivery plan moves forward', Upstream, 20 September 2017
[34] Gassco key figures, Gassco website, 2017

marketable gas to European entry points does compare very favourably with competing longer-haul suppliers, particularly when one takes account of the commercial flexibility the Gassco system is able to offer active marketers.

The government's authority to set gas tariffs was deployed in 2013 in an effort to encourage new gas field developments and to maximise the utilisation of existing infrastructure and the new Polarled pipeline. In June 2013, the MPE decided to reduce gas transportation tariffs by 90% for new bookings of capacity from 1 October 2016 on those mature parts of the Gassled-owned network which have already delivered their predicted financial return. Existing bookings made before June 2013 for capacity for any period up until the end of the Gassled license period in 2028 were not affected, nor were new bookings on less mature parts of the network. The aim of the tariff reform was to incentivise new exploration, development and production of gas on the NCS, particularly in less mature areas such as the northern Norwegian Sea served by Polarled. The effect of the proposed reform would be to ensure that new bookings for capacity, for example those associated with new field developments, would pay considerably less than existing capacity holders.

Unexpectedly, this MPE decision proved to be highly contentious. The four privately-owned shareholders who had bought a combined 45% stake in Gassled in 2011-12, backed by non-Norwegian infrastructure investors, brought court proceedings against the State, alleging the amendments were invalid and claiming financial damages because of an impairment of their expected future returns. In September 2015, the Oslo District Court rejected the plaintiffs' claims and upheld the government's amended tariffs. The plaintiffs appealed against this judgment. In June 2017, the Court of Appeal delivered its ruling on the appeal and once again upheld the government's revised tariff decision. In September 2017, the plaintiffs announced their intention to appeal against this latest ruling to the Supreme Court. Until this unusual litigation is concluded, probably at some time in mid-2018, the new tariff arrangements cannot be confirmed and prospective field developments must wait to see whether they will benefit from a lowering of their expected tariff costs.

8. Norwegian gas marketing and contract portfolio reform

All licensees on the NCS are responsible for selling their own gas. There are about 40 equity producers of gas on the NCS, all of whom have discretion over how, where and to whom they market their output. About thirty of these producers are registered shippers on the Gassco-operated processing and pipeline transportation system which gives direct access to the traded hub markets. However, in volumetric terms, the marketing of NCS gas is heavily concentrated in the hands of Statoil which, between 2010 and 2017, accounted for 70-85 bcma, or 70-80%, of total pipeline gas sales from the NCS[35].

Statoil markets its own equity production (42.9 bcm in 2017), the entitlement of the SDFI managed by Petoro (40.3 bcm) and an estimated 2-5 bcma purchased on the NCS from other smaller, privately-owned equity producers. Petoro's share of NCS gas production is greater than its share of oil output since it owns a 56% share of the giant Troll field and an unusually large share of both Ormen Lange (36.5%) and Åsgard (35.7%), the second and third largest producing fields; its typical participation in offshore licenses is 30%. Statoil is operator of the Troll and Åsgard fields; Ormen Lange is operated by Shell.

Petoro is not a license operator and all its oil and gas is marketed by Statoil under a 'marketing instruction' decided by the government in 2001 which gives Statoil a high degree of marketing discretion but also subjects it to monitoring and scrutiny by Petoro[36]. Since the equity entitlements of both Statoil

[35] Statoil's gas production and sales volumes are disclosed in its annual and quarterly reports and SDFI gas production is recorded in Petoro's annual reports and quarterly directors' reports.

[36] The marketing of SDFI oil and gas is fully described in Statoil's Annual Report and Form 20-F 2016 in sections 2.7 and 3.4 and in note 27 to the Consolidated Financial Statements.

and Petoro are marketed as part of a single portfolio, Petoro shares the costs and benefits of Statoil's 'asset-backed trading' of NCS gas in European downstream markets.

In the marketing of its gas, Statoil gives priority to meeting its contractual obligations to its term customers but it still enjoys a high degree of discretion over sales of uncontracted gas to NW European customers and markets. The priority given to term contract customers has established Statoil's reputation among European buyers as a secure, reliable supplier. Its flexibility in the marketing of uncontracted gas has conferred on Statoil a strong influence over supply to the traded hub markets which ensures that the flows of Norwegian gas to all major entry points are watched closely by market participants. Since the early 1990s, Statoil has developed an expertise and asset position in traded gas markets of NW Europe unrivalled by other major suppliers of gas to Europe. The underlying objective of its marketing is the achievement of the highest possible value of its remaining gas resource base.

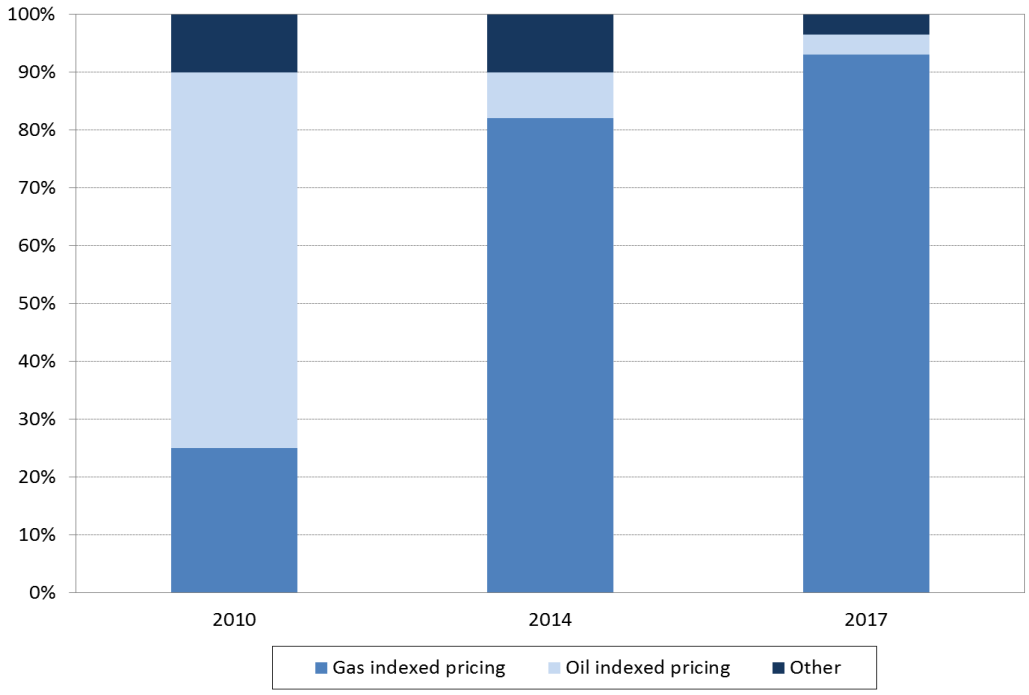
In 2010, Statoil showed its willingness to restrain output at key swing fields, principally Troll, at a time of weak demand and acute over-supply in European markets by adopting publicly a policy of 'value over volume'[37]. Statoil announced its intention to restrain short-term volumes by deferring production, but it did not set any objective related to price levels or price stability. The restraint was later relaxed and Troll output raised but the policy remains intact. Statoil remains committed, when it considers it economic, to using its upstream and midstream flexibility to restrain its short-term supply to restore balance to traded gas markets, as it did most recently in 2016[38].

Statoil's sales portfolio has undergone fundamental reform since 2010 as a result of the re-negotiation and reform of long-term contracts with continental European buyers which followed the period of acute over-supply in 2009-10. We believe this reform process has had an important consequence of weakening the link between term sales contracts and upstream investment in new sources of gas supply and in reducing the visibility of future gas supply from the NCS.

Figure 14 illustrates the shift in the pricing basis of Statoil's sales portfolio of 75-80 bcma between 2010 and 2016. In many cases, the renegotiation followed the formal triggering of price review clauses by continental buyers but the process was widened to a more fundamental review of the sustainability of long-term oil-indexed contracts in increasingly liberalised continental markets with growing hub market liquidity. The share of total volumes indexed to oil prices fell from 65% in 2010 to 8% in 2014 and just 3% in 2016. By 2016, the share of hub price-indexation in its total sales has risen to 93%. The corollary of this dramatic shift in price-indexation is the reduction or, in some cases, the elimination of the intra-year volume flexibility buyers formerly enjoyed under oil-indexed contracts and the change in the contractual delivery point from specific entry points to hub markets such as TTF, NCG or PEG. This gives the seller the additional flexibility not to flow gas to meet its contractual obligations but to purchase gas at the hub to do so.

[37] The deferral of gas production in 2010 and the 'value-driven gas strategy' was confirmed by Rune Bjornson in an interview with Reuters on 4 October 2010.
[38] Statoil results for 2Q 2016, Financial Statements and Review, page 6.

Figure 14: Statoil's European Gas Sales Portfolio 2010-2017

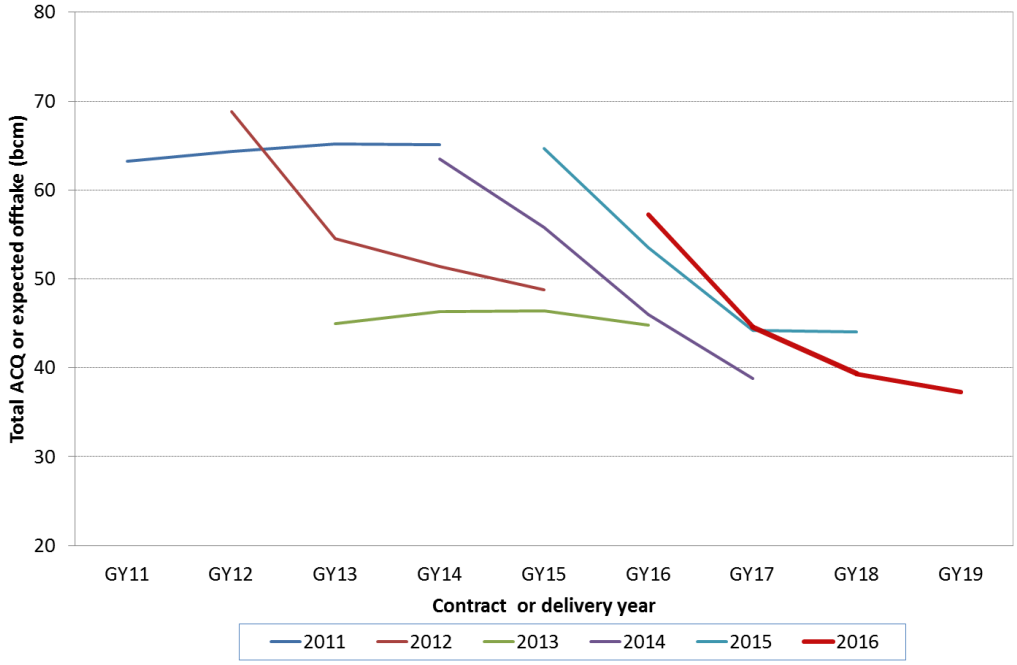


Source: Statoil Gas Seminar February 2018

Statoil does not disclose details of its term sales contracts but since 2011 it has provided a limited summary of its annual delivery commitments for the following four years arising from its existing long-term contracts[39]. These obligations are met by deliveries of gas from the joint portfolio of gas resources owned by Statoil and the SDFI. These reported figures are reproduced in Figure 15. In 2011, the delivery commitments in the following four years were almost flat at 63-65 bcma. Within two years, the future commitments had fallen to about 45 bcma. By 2016, when the contract renegotiations were largely complete, the delivery commitment in 2017 had risen to 57 bcm but in 2020 it stood at only 37 bcm, barely half its expected gas sales in 2020. Statoil also reported in 2017 that more than half its gas sales (>35-40 bcm) were delivered under long-term contracts with take-or-pay clauses. We can deduce from these figures not only that its term contract commitments have declined but also that the average tenor of its term contracts has contracted. It appears that a significant part of Statoil's sales (perhaps 10-15 bcma) is now delivered under short-term bilateral contracts of one or two years' duration signed close to the beginning of the delivery period.

[39] Statoil's delivery commitments at the end of 2016 are described in the Annual Report and Form 20-F 2016 in section 2.8 'Operating and Financial Performance' p.48

Figure 15: Statoil's Delivery Commitments under its Term Contracts



* 2016 projections are for calendar years 2017-2020, not contract years

Source: Statoil annual reports 2011-2016

In summary, Statoil's term contract portfolio has become more diverse in tenor and duration and more uniform in its pricing basis since almost all contracts are now linked to TTF or NBP prices. The former distinction drawn by Statoil between (oil-indexed) 'long-term contracts' and (hub-indexed) 'short-term sales' has now been replaced by a distinction between 'bilateral sales' to known customers under a variety of long and short-term contracts and 'hub sales' where the counter-party is often unknown. In 2016, bilateral sales, mainly to industrial users, power generators and distribution companies, accounted for more than half the total sales volume.

The reduction in the size of Statoil's *total* future delivery commitments reinforces the impression of profound change to its contract portfolio. At the end of 2011, Statoil reported that it had total future delivery commitments of 675 bcm. By 2016, its total future commitments were 329 bcm, a decline of more than 50% in just five years. Throughout this period, both Statoil and Petoro held sufficient gas reserves to meet all their shared delivery obligations which extended to the early 2030s. At the end of 2011, their gas reserves were 445 bcm and 800 bcm respectively. The contract renegotiation with buyers was guided by the principle of enhancing long-term economic value on the NCS. The consequence of the contract portfolio changes is that both Statoil and the SDFI/Petoro now have much greater flexibility in the management of their NCS gas resources and greater discretion in their capital budgets, particularly over the timing of new investments to meet their remaining delivery obligations to their term contract buyers.

The upstream impact of the contract portfolio reform is already evident in the Norwegian upstream. Statoil and its partners have been able to defer decisions on future gas field development since its future delivery commitments have been reduced and they are no longer required contractually to maintain the same degree of swing and flexibility. Troll has been capable of responding quickly to fluctuations in demand and producing at peak 120 mcm/day[40]. In the future, the licensees may choose

[40] NPD field data show a record monthly average of 121 mcm/d in December 2012.

to invest to slow the erosion of the flexibility of their output but they would do so based on their own market-based valuation of such flexibility, not on contractual obligations under long-term contracts. This represents an important gain in value to the Norwegian upstream, in particular to Petoro and Statoil, because of the expected increase in the cost of maintaining wellhead flexibility as the Troll field matures and reservoir pressure declines. For Petoro and Statoil, the option to defer capital expenditure on NCS gas field developments was made more valuable by the fall in oil prices in 2014-16 at a time when capital expenditure on the larger and more valuable Johan Sverdrup oil project was rising towards its peak.

In summary, the profound changes since 2010 in the marketing of Norwegian gas by Statoil has relaxed some of the constraints on overall NCS gas resource management. They have had the effect of weakening the previous link between Statoil's term sales commitments and future upstream gas development on the NCS by reducing both the annual volume of future sales commitments and the flexibility needed from NCS fields in the future. Reform of Statoil's contracts has permitted the development of existing discoveries by other producers without regard to Statoil's sales commitments, levelling the playing field for some smaller discoveries where Statoil has only a small stake.

9. Conclusions: renewed confidence in NCS gas supply

The official projections of NCS gas production represent plausible estimates of the future capability of the NCS upstream, comprising both the resource base and the adequacy and reliability of the processing and transport infrastructure. The NPD is in a uniquely privileged position to understand operators' plans and its track record in making such projections has been fairly good. In 2017, the NCS produced 122 bcm, within the range identified by the NPD in 2007 before the sharp downturn in European demand. The restoration of gas demand growth, the loss of swing and flexibility in NW Europe since 2016 and new investment in NCS gas projects have given the Norwegian industry greater confidence that recent output is sustainable until at least 2023. Unless European demand suffers an unexpected decline, the risk of the NCS falling significantly short of the current projections of 120-125 bcma up to 2023 appear to be low.

The shift in gas contracting behaviour in Europe since 2010 and the move to hub-based pricing has fundamentally changed the relationship between Statoil's marketing strategy and NCS upstream investment. Reform and liberalisation downstream has been accompanied by new flexibility over gas field investment on the NCS, to the benefit of all gas resource holders. The visibility of future NCS gas exports has declined but the capability of the NCS to deliver gas has been enhanced, assuming that new investment is capable of being remunerated by oil and gas prices. The NCS will never be a source of 'low-cost gas' but the success in reducing development and operational costs since 2014 and the responsiveness of the Gassco-operated infrastructure suggest that Norway will continue to be a competitive gas supplier to Europe well into the 2030s.

There are a number of sources of 'new' NCS dry gas supply in the next five years: the northern Norwegian Sea via Polarled delivering first gas in 2018-19, an expected approval of Troll Phase 3 bringing new gas to Kollsnes by 2021-22, the associated gas from the first phase of the giant Johan Sverdrup field beginning in late 2019 and, possibly, a reduction in the demand for gas for reinjection and improved oil recovery at existing mature oil fields.

After declining in recent years as Ormen Lange and Åsgard have come off plateau, output from the Norwegian Sea will start to rise again as Aasta Hansteen begins production at the end of 2018 via the Polarled pipeline. The operator Statoil expects Aasta Hansteen will deliver 6.0-7.5 bcm pa. Only two other smaller fields (Dvalin and Snefrid Nord) in the northern Norwegian Sea have so far taken FID, so Polarled will be underutilised in its early years. Considerable capital cost barriers and the question of access to gas processing capacity offshore and onshore will have be addressed before FID is taken at other known discoveries capable of being tied into Polarled.

The recent approval to raise Troll's permitted output from 30 bcm in 2015-16 to 36 bcm in 2017-18 signalled a shift towards greater tolerance by the NPD of higher gas output and sales; an expansion of gas sales is no longer deemed to pose a risk to remaining oil recovery. We expect that, after several years of deliberation and study, Statoil will submit plans for Troll Phase 3 in 2018, leading to the installation of two subsea templates tied back to the Troll A platform to tap gas reserves in Troll Vest by 2021. The new investment is expected to allow gas production of 36bcma to be maintained for seven more years, through the 2020s, and to extend the producing life of the Troll field until 2063 assuming a licence extension[41].

Since 2010, the gas output from non-Troll fields in the North Sea has increased by 10 bcma to a record 42 bcm. This is testimony to the industry's success in increasing recovery from mature fields like Ekofisk and in tying in numerous small discoveries into existing Area D infrastructure. The commissioning of the first phase of the giant Johan Sverdrup oil field in 2020 will add to such North Sea supply delivered via Statpipe to Kårstø. The proportion of associated gas in initial production will not be high but as subsequent phases are added in the 2020s, the sheer size of Johan Sverdrup will provide an additional source of dry gas supply, at least until such time as gas injection is adopted to maintain reservoir pressure and long-term oil recovery.

The fourth source of potential new dry gas supply, reduced injection demand in mature oil fields, is much less certain. All we can observe at this stage is that the profile of demand for gas injection at the first oil fields to be developed, such as Statfjord, now suggests that aggregate demand for gas injection into later oil fields like Oseberg may be on the point of diminishing, freeing up more gas for sale.

The gas production outlook beyond 2025 necessarily carries progressively more geological, economic and political risks which are not explicitly addressed in the current NPD projections. It is notable that the central case NCS production profile beyond 2030 is so dependent on output from resources which have not yet been discovered and that so much of this undiscovered resource lies in the Barents Sea where the economics of development are most difficult[42]. Nevertheless, despite the risks, the projection of production of 90 bcma in 2030-35 does not at present appear imprudent or implausible given the impressive record of raising recovery from producing fields and in tying in small discoveries in mature areas.

The government is committed to maintaining the pace of NCS exploration activity and a strong fiscal incentive for further drilling but the opening of new sensitive areas to exploration will not take place before 2021. It would be a mistake to dismiss or to downgrade the potential of the Barents Sea to produce more gas beyond 2025 merely because of the paucity of discoveries in recent years and the very disappointing drilling results in 2017. Since exploration began in 1980, only 162 wildcat and appraisal wells have been drilled in the Barents Sea, and there are still large areas which are at a very early stage of exploration or not open to exploration. Unfortunately, both the first gas development in the Barents Sea (Snøhvit in 2007) and the first oil project (Goliat in 2016) suffered cost overruns and early production problems that have set an unwelcome precedent for other prospects. Only if there are some commercial gas discoveries in the next five years and no major problems on the second large oil project, the Johan Castberg FPSO, can we reasonably expect the Barents Sea to realise current expectations for gas production between 2025 and 2035.

[41] Statoil Capital Markets Update 2018, page 11, 7 February 2018

[42] Gassco's Barents Sea Gas Infrastructure report (2014) provides a useful summary of the economic challenges for development of gas discoveries in the Barents Sea.

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