A phase-out plan for Norwegian oil and gas

A stepwise transition towards 2040

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mdg

Foreword

This is how we win the fight against climate change!

The transition of Norway from an oil-dominated economy to a society with sustainable value creation will be demanding, but offers great opportunities. The transition is necessary to achieve the climate goals in the Paris Agreement, and not least for Norway to maintain welfare, jobs and economic resilience of local communities.

As the world's richest country, with a high level of trust and a tradition of cooperation, we have all the prerequisites for success. Norway can become a global driving force in the energy transition and in the development of new zero-emission industries. But the scarcity of resources such as power, expertise and labour requires wise choices, so that the economy does not remain dependent on an export product that the world does not need in the future.

This is The Norwegian Green Party's (Miljøpartiet De Grønne, "MDG") proposal for a detailed strategy for how we can round off the oil age towards 2040 in a predictable and gradual manner. It is a demanding exercise to which we do not claim to have all the answers, but we welcome a debate on the topic.

We invite you to a knowledge-based and targeted discussion on how we can succeed in transforming Norway. For this, we need input from the social partners, industry and research communities, as well as the broader political environment.

Let me extend my gratitude to our internal *oljenettverk* ("oil network") for providing MDG and Norway with this knowledge base, and thank you to everyone else who is joining the discussion.

Ingrid Liland
Chair of the Program Committee and Vice Chair of the Green Party

Executive summary

The world and Norway are in the midst of a green transition. To prevent dangerous climate change from affecting water supply, access to food, safe housing and peace, fossil fuels must be phased out and replaced by renewable energy. As one of the world's largest exporters of fossil energy, Norway will be important for speeding up this transition. That is why Norway needs a strategy for the final phase of Norwegian oil and gas, as recommended by the Climate Committee 2050 and Statistics Norway.

Norwegian value creation must contribute to the fastest and safest possible transition, in the world and in Norway. Norway's largest customer, Europe, must transition away from fossil fuels according to the conclusions of the COP28 in Dubai. The UN Secretary General has asked rich countries to become zero-emission societies by 2040. Norwegian exports must consist of goods and services that contribute to this transition, and ensure lasting reductions in greenhouse gas emissions and the development of clean energy supplies. This strategy will ensure that Norwegian oil and gas sector is phased out by 2040, with three objectives:

1. Accelerate the energy transition in Norway and Europe
2. Free up resources for emission-free value creation in Norway
3. Implement the transition in a predictable and safe way for people and businesses

In the strategy, we use the variation within fields on the Norwegian continental shelf to prioritize between different oil and gas fields, and propose a stepwise sequence for decommissioning the fields. This sequence maximizes emission reduction, ensures gas supply to Europe in the short term, and minimizes economic consequences and resource use. Electrification of the Norwegian continental shelf and blue hydrogen are not currently included in our plan due to the large required use of scarce resources.

Current policies for fossil fuels

The Norwegian debate related to extraction and consumption of fossil fuels is currently polarized and characterized by selective use of facts. Demand in Europe for oil and gas will have to drop drastically to meet climate targets, but is nevertheless used as an argument for making long-term investments in Norway. The great variations within oil and gas fields on the Norwegian continental shelf are not adressed, although these can be significant in terms of profitability, intensity in production emissions, remaining reserves and the proportions of oil and gas produced.

The strategy of the current government is based on technological solutions with high resource consumption in the form of electrification with electricity from shore and the production of blue hydrogen. This is despite the fact that electricity is becoming an increasingly scarce resource, and the future profitability of new technologies is highly questionable. The government itself has said that oil and gas will be phased out, but the result is high investments in oil and gas, and a Norwegian economy that remains dependent on export revenues from the very products that will be phased out.

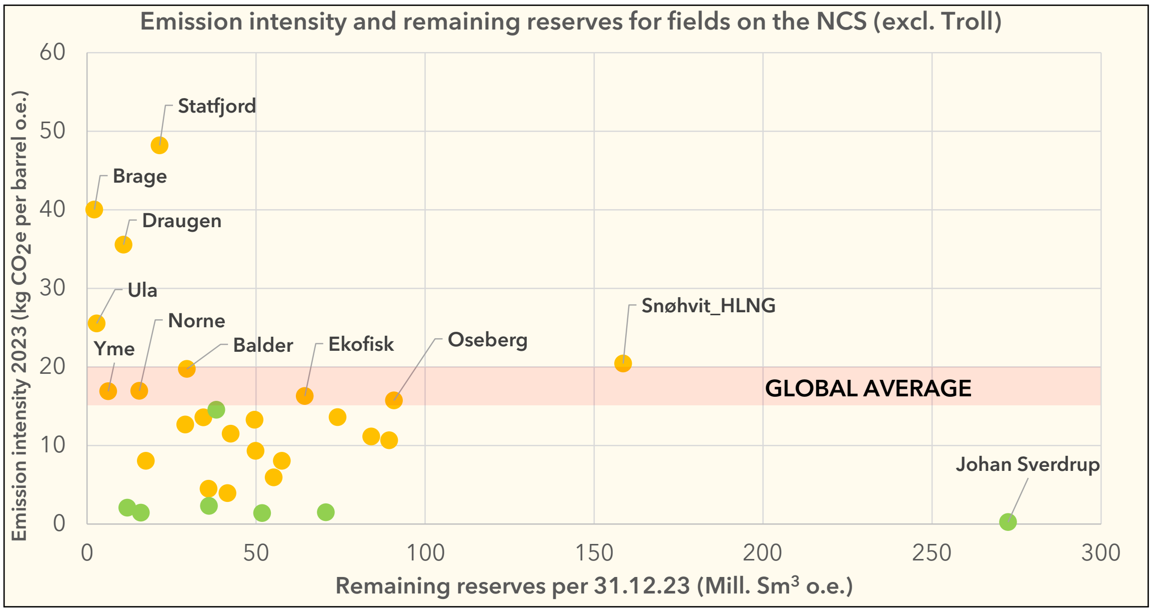
Access to expertise and labor are the most important input factors for solving the challenges of the transition phase. Unfortunately, he Norwegian debate has little to do with the fact that oil and gas is taking up precisely these factors and thus preventing growth in new and innovative industries.

This strategy shows what a phase-out could look like, and what consequences it could have. Such a plan is essential if Norway is to participate in a global transition away from fossil fuels. Likewise, for reducing Norwegian greenhouse gas emissions, making the Norwegian economy more robust and diverse and to ensure competitive exports.

Even though our plan is based on thorough analysis, we do not claim to have all the answers. We therefore hope that this report contributes to the debate of the best way forward.

Our conclusions

Discoveries on the Norwegian continental shelf occur less frequently and are smaller than before, despite high exploration activity. Many fields have little left to produce with consequent high levels of greenhouse gas emissions. It is claimed that the Norwegian shelf has *"the world's cleanest oil"*, but a handful of fields already have higher emission intensities than the global average. Without electrification or new discoveries, the emissions intensity will *increase* over time, as the figure below clearly shows. Prioritizing decommissioning of fields according to emission intensity is a cost-effective way to reduce emissions, as high-intensity fields also tend to be less profitable and thus contribute little to government revenues and the Norwegian economy.



Overview of the emission intensity and the amount of remaining reserves for selected fields on the Norwegian continental shelf. The global average emission intensity is also indicated. Note that in order to increase readability of the figure, the Troll field is not included due to its size.

In the work on our phase-out plan, we have drawn on expertise in forecasts for oil and gas production, electricity consumption and emissions. We have made forecasts for each individual field, and built up a total forecast for the shelf from this. We have done this to achieve a plan as realistic as possible, with as credible estimates of consequences as possible. Although our forecasts are not very different from those of the Norwegian Offshore Directorate, and there is still a great deal of uncertainty surrounding forecasts, we would like to continue the dialogue with partners who have more accurate data so that we can improve them.

Our plan assumes an immediate halt in exploration activities and that no further investments are made that lead to increased production or extended lifespan, including electrification projects with power from shore. In our analyses, we show a scenario with the effect of this important measure, and thus why it is crucial to contribute to a rapid and safe transition in Norway and the world.

The strategy has the following phases:

1. Shutting down old fields with high emission levels and relatively low profitability. These are fields that primarily produce oil and hence do not contribute to Europe's transition away from Russian gas.

2. Shutting down fields successively, as they exceed the global average for emission intensity. This is supplemented by not renewing production licenses for a number of fields where the situation indicates that they should be shut down instead.

3. Shutting down electrified fields to free up power for other purposes that contribute to the green transition.

Our phase-out plan achieves *"zero emissions"* during the year 2040, as well as a significant reduction in the use of electricity from shore measured against "*business as usual*" (i.e., a continuation of current policies). Based on analyses of previous oil crises as well as forecasts from other actors, we expect that employment at the national level will not be a major problem. However, local challenges are likely to arise, and separate "transition commissions" with local knowledge should be established to find good solutions. In the "*worst case scenario*", where we do not take into account either possible market failures with corresponding price drops for petroleum products (in "*business as usual*"), reduced investment costs for the state with our plan, or increased earnings from other industries, we find that the total possible drop in revenue by following the steps in the phase-out plan is approximately NOK 70 billion annually, or 20% of the state's total revenue from petroleum for the period up to 2050. This is without taking into account that other industries will emerge and provide new tax revenues when resources are released.

Table 1: Selected key numbers quantifying the effects of our proposed phase-out plan. Electricity need and aggregated revenue towards 2040 are compared to the "business as usual" reference case.

Emissions in 2040 (relative to 2023)	Electricity need from shore (2040)	Government's revenue, total towards 2040 (worst case)
-98%	- 12 TWh/year	-1 400 billion NOK

The tools for achieving this plan are an increased CO2 tax on the Norwegian continental shelf and the introduction of a transition tax per unit produced. The transition tax is a necessary supplement to ensure that electrified fields are also affected. In addition to these fees, the practice of renewing production licenses must be tightened considerably, so that the expiry of licenses supplements the financial incentives. We also propose a support scheme for plugging wells and decommissioning, so that companies can get started with this important work quicker than the current pace. To ensure that decommissioning takes place in a safe and predictable manner, our strategy calls for cooperation with the labor unions, the industry partners and, in particular, strong local cooperation. This would would be in accordance with traditions for dealing with temporary, local employment challenges in Norway.

The figures, methodology and report have been prepared by MDG's internal "oil network" led by Marius Heide and Andreas Ormevik. The content is supplemented with contributions from a working group consisting of Margit Martinsen Bye, Gunn Kari Hygen, Ivar Henry Larsen and Paal Frisvold, under the leadership of deputy chair Ingrid Liland.

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1 Introduction

Norway as a nation has much to thank the petroleum industry for. Since production started at Ekofisk in the summer of 1971, it has provided stable income that has been wisely managed both to strengthen the welfare state and to build up a fortune for future generations through the Oil Fund – which has now exceeded 18,000 billion kroner in value. The petroleum industry has employed hundreds of thousands of people for a long time and has been particularly important in ensuring population growth and activity in many coastal communities. The Norwegian continental shelf has also been an arena for world-class technology development, and skilled oil workers and professionals have seen opportunities, seized chances and delivered solutions that were previously considered impossible to realize. Many of the solutions delivered in the petroleum industry have also been useful in other industries.

Much of the credit for the Norwegian oil adventure can be given to visionary and forward-looking politicians, as well as entrepreneurs and players in the business community - who, through many courageous decisions, have generated large revenues for the Norwegian state. At the same time, the management of the Oil Fund has meant that Norway has avoided overheating its own economy. The considerable financial wealth that the petroleum industry has given us gives us an opportunity few other countries can dream of.

However, the climate and nature crisis is already threatening the health, life, safety and quality of life of people and animals around the world. Now there is a renewed need for politicians, entrepreneurs and businesses to make bold and visionary choices. The UN has recommended that wealthy countries should reach net zero emissions in 2040, and as a rich country with significant oil and gas exports, Norway has a clear responsibility to take the lead in rapidly reducing greenhouse gas emissions. This applies to both domestic emissions, where oil and gas production has the highest emissions of all sectors, and our indirect impact on other countries' emissions, where exported oil and gas is by far our largest contribution. In other words, if we are to reduce emissions in line with our own targets and international commitments, there is a need for a major transition in Norway away from today's oil-dependent economy and business sector.

The ongoing transition also offers great opportunities for a more robust and diverse Norwegian business community. In the future, value and welfare will be created without destroying the climate and nature. This is fully possible if we release the creative power, labor and capital currently tied up in oil and gas, and do so in a predictable way that ensures that the business community and the economy as a whole can adapt and adjust gradually. Our proposed phase-out plan for Norwegian oil and gas provides this predictability, by gradually reducing the level of activity on the Norwegian continental shelf while releasing expertise, infrastructure, electricity and other resources for other purposes. In addition to phasing out oil and gas, Norway must focus on climate solutions and create green, circular solutions - so that we help to reduce costs and accelerate the transition *from* fossil and resource-wasting solutions *to* a renewable and circular society both in Norway and internationally.

Today's debate on a fossile phase-out in Norway

In Hurdalsplattformen, the Government's political platform, the government parties have stated that "*Norwegian petroleum industry will be developed, not phased out*", and that "*The government will facilitate a continued high level of activity on the Norwegian shelf*" (**our translations**). This is a widely used rhetoric, and most public debates on oil policy in Norway are characterized by this. In addition, a story is told about *"the world's cleanest oil"*, referring to the fact that production on the Norwegian continental shelf has a lower emissions intensity[1] than the world average. Nevertheless, the oil and gas industry accounts for the largest share of Norway's domestic greenhouse gas emissions

[1] Emissions intensity is a measure of CO_2 emissions per produced unit (barrel or Sm^3) of oil or gas

of all sectors; about a quarter of total Norwegian emissions with 11.5 million tons of CO_2 equivalents (CO_2e) annually (numbers from 2023).

Like the Norwegian state and large parts of the business community, the Norwegian continental shelf also has targets for reducing greenhouse gas emissions. The collaborative body KonKraft[2] launched its own climate targets for the Norwegian continental shelf in 2020, aiming for a 40% (later raised to 50%) reduction in emissions in 2030, and close to zero emissions in 2050, compared with emissions in 2005. The strategy for achieving these goals involves electrification (primarily with onshore electricity) as by far the most important measure. Other measures include more energy efficiency and scaling up carbon capture and storage of CO_2.

Klimautvalget 2050, an expert committee appointed by the Government in 2021 with the aim of showing how Norway can become a low-emission society in line with the Climate Change Act, recommended in its NOU report ("Official Norwegian Report") presented in October 2023 that "*a strategy for the final phase of Norwegian petroleum activities should be prepared and presented to the Storting as quickly as possible*". In addition, they recommended that "*no further Plans for Development and Operation (PDO) or installation and operation (PIO) should be granted until such a strategy is completed*", and "*as a general rule to avoid electricity from shore as an emission-reducing measure*" (**our translations**).

Stakeholders in the petroleum industry have submitted their critical responses to these recommendations through the public consultation ("hearing") process. The industry association Offshore Norway commented in its consultation response the need for electrification to reduce emissions from the Norwegian continental shelf, and that reductions in oil and gas production must be governed by reductions in demand. They believe that further exploration on the shelf is necessary to avoid an energy crisis in Europe, and point out the importance of the lowest possible production emissions. Furthermore, the Norwegian Offshore Directorate commented in its consultation response that the possibility of meeting climate targets in 2050 through the purchase of climate quotas had been disregarded, and that scenarios other than the IEA's net zero (NZE) had not been considered. They also called for socio-economic analyses of exploration shutdowns and lower activity, and a greater focus on security of supply. They also explicitly pointed to new gas infrastructure in the Barents Sea, and that this could create long-term value.

Even though a minority of political parties propose a halt to exploration in their programs, and opposition to electrification of the shelf is growing, the consultation responses to the NOU are indicative of the debate on phasing out Norwegian oil and gas:

- The arguments are based on the current energy situation in Europe and assumes sustained high demand and high prices for oil and gas.
- There is no differentiation between fields on the continental shelf (oil or gas fields, or the age of fields), in particular there is a lack of focus on major differences in profitability and emission intensity.
- Doubts are being raised about whether Norway needs to reach its climate targets with territorial reductions, and whether the world will reach net zero emissions in 2050.
- Solutions that favor continued high activity in oil and gas are promoted, such as the production of blue hydrogen, electrification using power from shore or electrification using offshore wind.

[2] Offshore Norway, the Federation of Norwegian Industries, the Norwegian Shipowners' Association, NHO, and LO (Fellesforbundet and Industri Energi)

- There is little focus on the fact that a high level of investment in oil and gas hinders growth in new, green industries.

What does the future look like for the Norwegian shelf?

The current situation is that Norwegian oil and gas is an important part of the energy mix in Europe. Since Russia's invasion of Ukraine in 2022, Norwegian gas has been one of several important solutions in Europe's transition away from Russian gas. In 2023, Norwegian gas accounted for 30% of gas imports to the EU, and Norway is undoubtedly an important energy supplier for the European continent. However, the current situation is not particularly relevant in the discussion about phasing out Norwegian oil and gas; petroleum activities have a long time horizon, and the strategy for the Norwegian continental shelf must therefore be assessed based on long-term forecasts.

Forecasts for oil and gas production are generally highly uncertain for several reasons: The market and the development of demand/price is the most important factor, because it will determine which fields are considered profitable for development and how long operation will remain profitable. In addition, there are a number of technical aspects that need to be considered, with production capacity, technology development and, not least, the inherent physical complexity of the reservoirs as important elements. Due to this high level of uncertainty, it makes more sense to operate with different "*scenarios*" for the future resource base and production. The Norwegian Offshore Directorate has established three scenarios for the overall production development on the Norwegian shelf up to 2050, which are shown in Figure 1:

- *Expectation*: This is based on current policy and the companies' reported forecasts. Exploration activity is initially high for a few years, before gradually declining. Exploration primarily takes place close to existing infrastructure, so that new discoveries are linked to it.

- *Low resource growth and little and late technology development*: Exploration activity is declining faster and fewer discoveries are being made than expected. In addition, few projects for increased recovery are being carried out, so the total investment level is also falling rapidly from the current level.

- *High resource growth and extensive and rapid technology development*: New discoveries are being made rapidly, as well as several major discoveries in immature areas – including gas discoveries in the Barents Sea that in this scenario has been decided to explore and develop at a great scale.

All three scenarios show a marked decline in production. The expectation path's production in 2050 is approximately 65% lower than the current level. In other words, it is *expected* that the age of Norwegian oil and gas production is entering its final phase.

95% of both oil and gas exports from Norway go to the EU and the UK. Gas exports are in practice tied to Europe through the established pipeline network (with the exception of LNG from Melkøya), and although oil is sold in a global market, it is primarily Europe's future development that is decisive for the development of demand and price for Norwegian oil and gas. In the new geopolitical situation, the EU has a strong focus on avoiding import dependency on fossil energy, and has through its climate package Fit for 55 set a goal of phasing out the use of Russian gas by 2027. In RePowerEU, a binding target for the share of renewable energy has been tightened to 42.5% in 2030, and according to the revised Energy Performance of Buildings Directive, fossil gas for heating must be phased out by 2040. In addition, the EU has adopted a legislative package on the gas and hydrogen market that sets an explicit end date for long-term contracts for fossil gas in 2049. On the recommendation of the EU's Scientific Committee on Climate Change, the European Commission has proposed that EU countries must reduce their greenhouse gas emissions by 90-95%

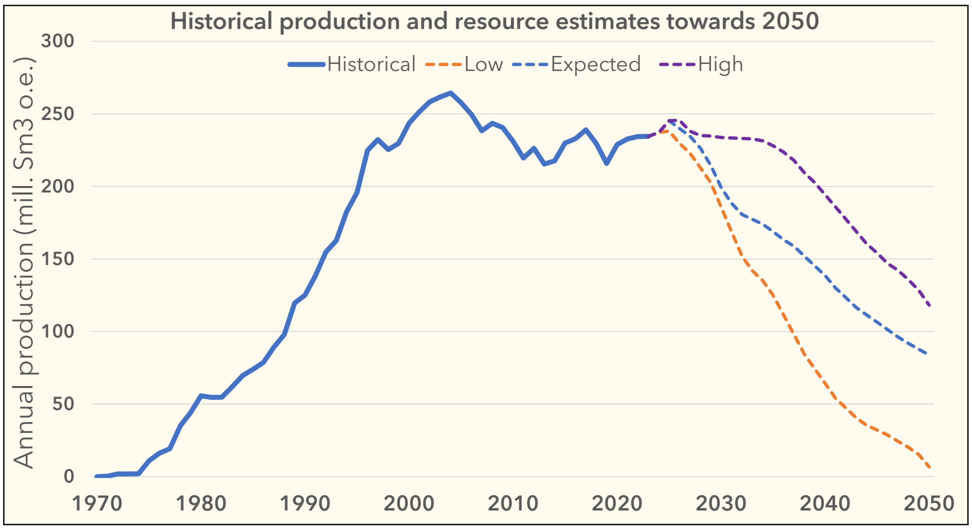


Figure 1: The Norwegian Offshore Directorate's scenarios for future production volumes on the Norwegian continental shelf. The numbers are based on their annually released Resource report 2024.

by 2040 (compared to 1990) to stop global warming at 1.5 degrees.

According to Zero Carbon Analytics and as illustrated in Figure 2, the European Commission's proposal for a 90% reduction in emissions by 2040 will mean that demand for gas will fall by 66% compared to current levels. Given this 90% reduction in emissions, contracted gas from the EU, Norway and Algeria is already sufficient to meet gas demand in 2040. This means that no new projects or more exploration is needed either in Norway or in other countries that sell gas to the EU. In a net-zero scenario, demand in 2040 will be reduced by as much as 90% compared to current levels. While the EU is working to phase out fossil fuels and increase the use of renewable energy, Norway is insisting on more exploration and increased long-term investments to meet a demand that is highly uncertain. A coordinated approach is needed to ensure a sustainable and reliable energy future for both the EU and Norway.

Nor is there a safe place for Norwegian oil and gas in a global perspective, if the world follows through on its climate commitments. In a study published in Science, British researchers reach the same conclusion as the IEA; no new oil and gas fields are needed in a world where we reach the target of global warming not larger than 1.5 degrees.

Fossil phase-out from the financial and safety perspectives

When a field ends its oil and gas production, all wells must be permanently plugged in a safe and environmentally sound manner, and facilities must generally be removed. This phase is regulated by Section 5 of the Petroleum Act, Chapter 6 of the Petroleum Regulations and the Oslo-Paris Convention (OSPAR). The OSPAR Convention only permits the abandonment of infrastructure in special cases. It is the Ministry of Energy that decides on disposal, and licensees/owners (i.e. oil companies) are responsible for implementation. Through tax deductions the state indirectly covers 78% of the costs associated with decommissioning and disposal of facilities (in the case of direct ownership through the SDFI/Petoro, the state will cover more than this).

Today, there are over 2,000 well trajectories remaining to be plugged on the Norwegian continental shelf, and even more will be drilled in the years to come. There are also 12 concrete facilities, 86 steel facilities and around 500 subsea installations. Only a handful of fields have been plugged and abandoned permanently so far; most of these are small. SINTEF has estimated that plugging wells

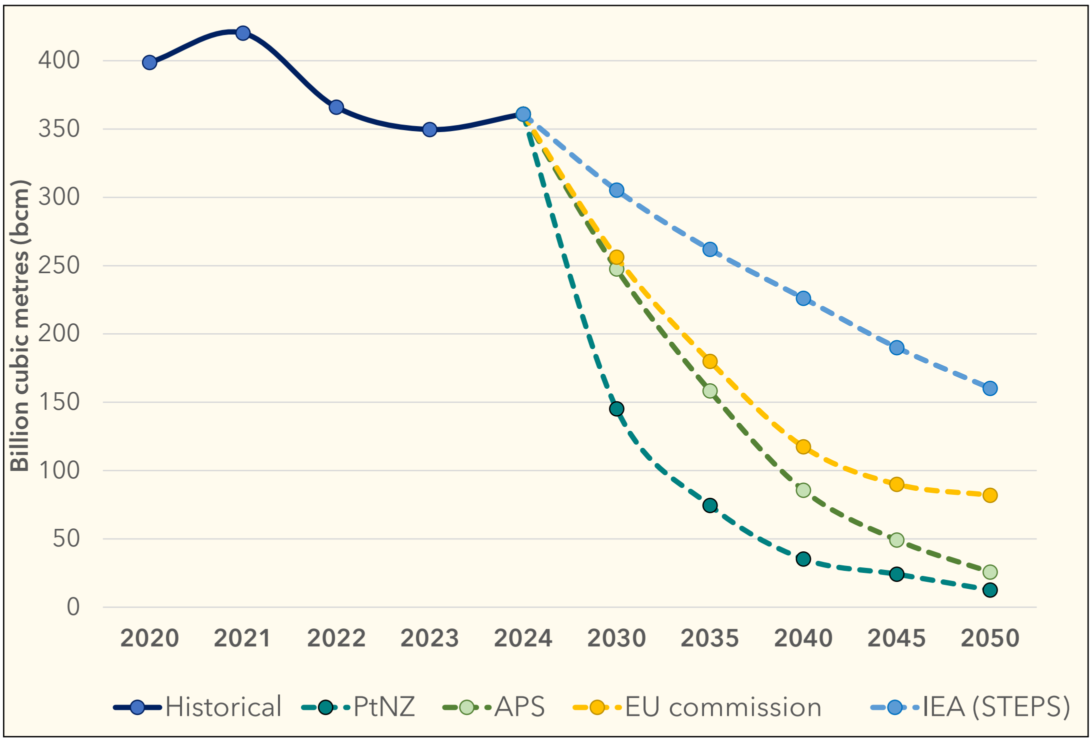


Figure 2: Expected trajectories for future gas demands in the EU, in various scenarios based on analyses from Zero Carbon Analytics: The DNV's "Pathway to Net Zero" (PtNZ), the Announced Pledges scenario (APS), the European commissions plan for 90% emission reductions in 2040 and the IEA scenario based on the stated policies, STEPS. Note that the horizontal time axis is not scaled.

alone could cost a total of NOK 800 billion with today's technology, and in the UK sector, plugging wells is only estimated to account for less than half the total cost of decommissioning. These cost estimates are highly uncertain, but nevertheless illustrate the order of magnitude.

Most fields on the Norwegian continental shelf (NCS) have had their lifetime extended in accordance with the plan for development and operation (PDO), see Figure 3. Although the petroleum industry is subject to strict legislation and monitoring related to HSE, it is reasonable to assume that the risk of accidents increases when the lifetime of the installations far exceeds what was planned. Increased focus on cost reductions with low financial margins in the tail phase can also compromise the safety aspect.

Since the job of decommissioning (which at some point has to be done anyway) is so extensive, a planned, accelerated and more even distribution of plugging, termination and disposal will provide several advantages:

- Reduced safety risk on very old installations.
- Incentive for faster technology development, which can result in lower total costs and lower environmental risk (related to methane leaks, for example). The technology can also be used outside Norway.
- The oil companies still have high earnings when plugging and disposal are carried out, which reduces the risk of payment problems and the ability to execute.
- Predictability for onshore reception facilities to ensure sufficient capacity.

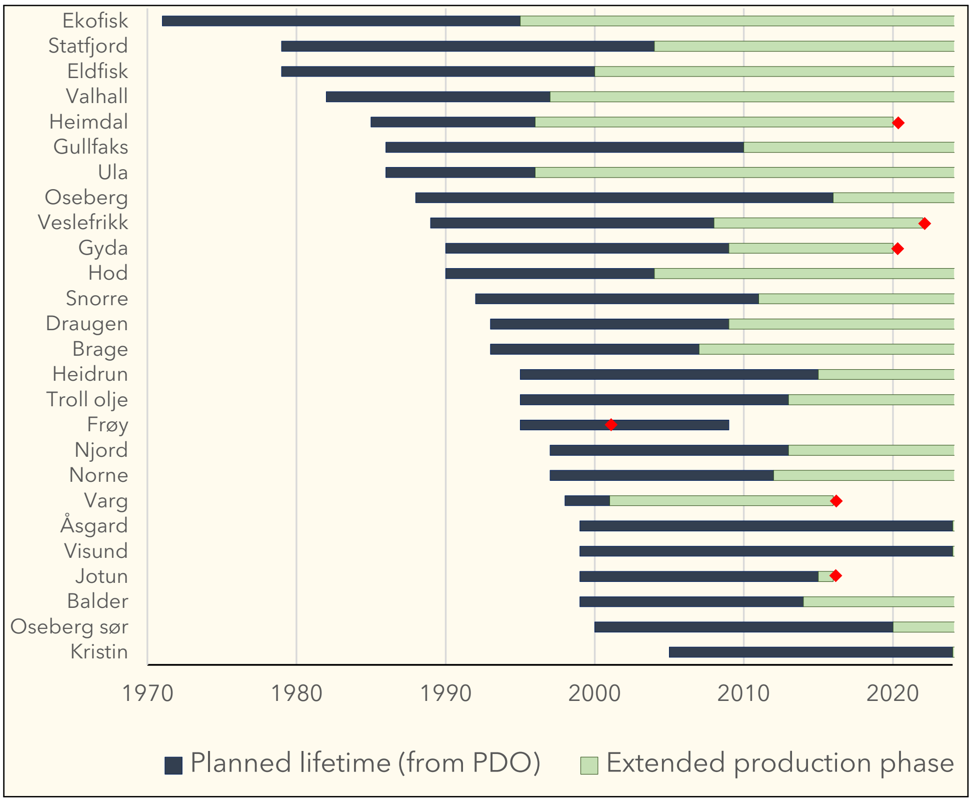


Figure 3: Initially planned and extended lifetimes for selected fields. Some fields have already shut down production, indicated with red dots. Note also that the large majority of fields is planned for extended production phases beyond 2030. Numbers retrieved from Norskpetroleum.no.

Employment in the Norwegian petroleum industry

Statistics Norway's *ringvirkningsanalyser* ("ripple effect analyses") indicate that just under 100,000 people are employed in petroleum-related activities. Excluding those who produce general business services such as cleaning, accounting, catering and the like, approximately 26,000 people are directly employed in the extraction of oil and gas.

The petroleum industry, and the supply industry in particular, is vulnerable to rapid price fluctuations in the market. After the sharp fall in prices in 2014, many people lost their jobs, and this had an impact on unemployment - especially in petroleum-intensive regions such as Rogaland county. With high uncertainty about future demand and prices, a predictable and gradual phasing out of Norwegian oil and gas activities will be easier for oil workers to handle than such rapid, market-driven changes.

One lesson learned from the oil crisis in 2014 is that most of those who had to leave the petroleum industry abruptly found other jobs relatively quickly. The skills in the industry are diverse, and there is a great need in other industries for engineers, ICT technicians and electricians. According to an analysis (2023) from Statistics Norway, approximately 60% of those who quit / lost their jobs in 2015-2016 were back in work as early as 2017 – and of these, 75% then worked in other industries. By 2021, the unemployment rate among those who quit had fallen to 2%. Even in municipalities with a high level of petroleum activity, unemployment had returned to the level before the fall in oil prices after just five years. This shows that even with rapid price declines, oil workers have relevant skills that make them attractive in many other industries, while illustrating that faster growth in green industries is prevented by the petroleum industry tying up important resources and expertise.

However, a gradual phase-out can be expected to have significant consequences for employment in the regions where a high proportion of people currently work with oil and gas, but there is reason to believe that the negative consequences can be mitigated by ensuring that the phase-out is predictable and announced well in advance.

Structure and purpose of this report

In Chapter 2, we explain the assumptions underlying our analyses and our phase-out plan, and the methods and data we use. The effects of the phase-out plan are dependent on these assumptions, and it is therefore important to be as transparent as possible in describing how we have proceeded.

In Chapter 3, we summarize the status of the Norwegian shelf as of 2024. The current debate on Norwegian oil and gas is characterized by referring to the shelf as a single unit - while in reality there is great variation between the fields. This chapter provides a good overview of production, emissions and electricity consumption - also in a historical context - so that the measures in our phase-out plan can be understood in light of this.

In Chapter 4, we present the actual phase-out plan, divided into different time-limited steps. For each step, we describe the principles we want to follow, which fields we propose to close when and why, and which political instruments can be used to realize the various steps in the phase-out plan.

In Chapter 5, we describe the effects of the phase-out plan. Here we cover both consequences for the economy and employment, as well as for greenhouse gas emissions and the use of electricity from shore.

With this phase-out plan, the Norwegian Green party (**MDG**) wants to present a more nuanced picture of the status of the Norwegian continental shelf, and to show in concrete terms what a controlled phase-out could look like and what consequences it could have. We would like to see other political parties and actors create similar plans, so that we can have a debate about *how* phasing out of Norwegian oil and gas should take place.

2 Assumptions and methodological approach

2.1 About the plan and scenarios

In order to present a proposal for a phase-out plan for the Norwegian petroleum industry, we need a solid data base and a consistent methodology for using this data. Broadly speaking, our plan is based on a "*bottom-up*" approach, where we have considered historical data, ownership, license periods, remaining reserves and future production forecasts for each field. In order to later present the effects of the proposed phase-out plan, there is also a need to define the following three *scenarios* for the future of the NCS:

- **MDG's phase-out plan** shows our proposed path for the final phase of Norwegian oil and gas. The decommissioning plan includes forecasts for production, revenue, greenhouse gas emissions and use of onshore power. A given field is shut down when one or more criteria occur.
- **No exploration and investments:** These are the forecasts for the fields that are in operation

today, as well as fields with *approved* PDO[3] and power-from-shore projects. Exploration and any new discoveries are also not included here, so that this scenario clarifies the effect of an immediate halt in exploration and investments.

- **Business as usual:** Our forecast for future production if the current petroleum policy is continued, exploration continues and more commercially viable discoveries are made. This scenario is the reference against which we compare the phase-out plan when quantifying the effects of our plan in Chapter 5. The scenario is similar to the Norwegian Offshore Directorate's expectation path up to 2035 (see Figure 1), while we then assume a lower production than the Directorate as we expect greater challenges with demand up to 2040 and 2050.

Figure 4 shows the production forecasts for these three scenarios, compared with the Norwegian Offshore Directorate's scenarios up to 2050. The forecasts are described in more detail in Chapter 4 and Chapter 5.

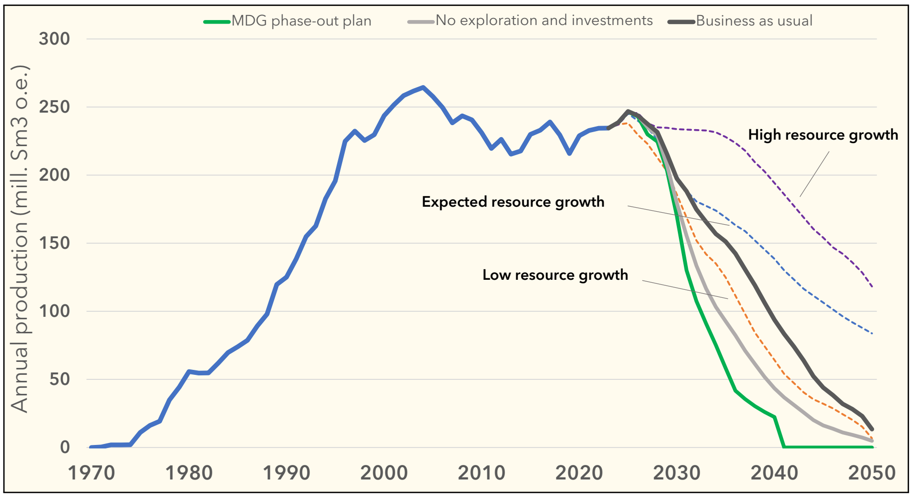


Figure 4: Our three scenarios for future production from the Norwegian continental shelf, compared to the scenarios launched by the Norwegian Offshore Directorate in Figure 1.

2.2 Scope and definitions

Fields

The Norwegian Offshore Directorate defines a **field** as: "*One or more petroleum deposits collectively covered by an approved plan for development and operation (PDO) or granted an exemption from a PDO*". In our analyses and in the phase-out plan, we will instead use this definition throughout:

> Our definition of **field** in the decommissioning plan: A cluster of fields (i.e. fields as defined by the Norwegian Offshore Directorate) and/or installations that have a common development solution and are not appropriate to divide into smaller units when discussing decommissioning. In some cases, our definition overlaps with that of the Norwegian Offshore Directorate, for example for Johan Sverdrup and Snøhvit.

There are several reasons for this simplification. First and foremost, greenhouse gas emissions are reported where they physically occur, i.e. allocated emissions for satellite fields connected to an installation are not available - it is also a very complicated exercise to allocate emissions between fields that share the use of the same equipment, such as gas compressors or water injection pumps.

[3] PDO: Plan for Development and Operation

In addition, it does not make sense to shut down a "main field" (e.g. Heidrun) while satellite fields are still in operation.

With our field definition, there are currently 32 fields in operation (see full overview in Appendix I), while two fields (Johan Castberg and Yggdrasil) have approved PDOs and are scheduled to come on stream in 2024 and 2027, respectively. Figure 5 shows how we have divided the Tampen area into the fields Statfjord, Gullfaks, Snorre and Visund. Some examples from our field division that are worth noting are:

- Edvard Grieg / Ivar Aasen is considered as one field, which also includes Solveig, Hanz (both in production) and Symra (PDO approved).
- Gullfaks is considered to be a single field, even though the Gullfaks field contains the Gullfaks A, B and C platforms. The satellite fields Tordis, Gullfaks South, Gimle, Visund South and Sindre are also included. The same logic applies to other fields that have several main installations, i.e. Ekofisk, Eldfisk, Johan Sverdrup, Oseberg, Sleipner, Snorre, Statfjord, Troll, Valhall and Åsgard.
- Sleipner / Gina Krog / Gudrun is considered a single field, which also includes Gungne, Sigyn, Utgard (all three in production) and Eirin (PDO approved).
- Yggdrasil is considered to be one field, consisting of Fulla, Hugin and Munin.

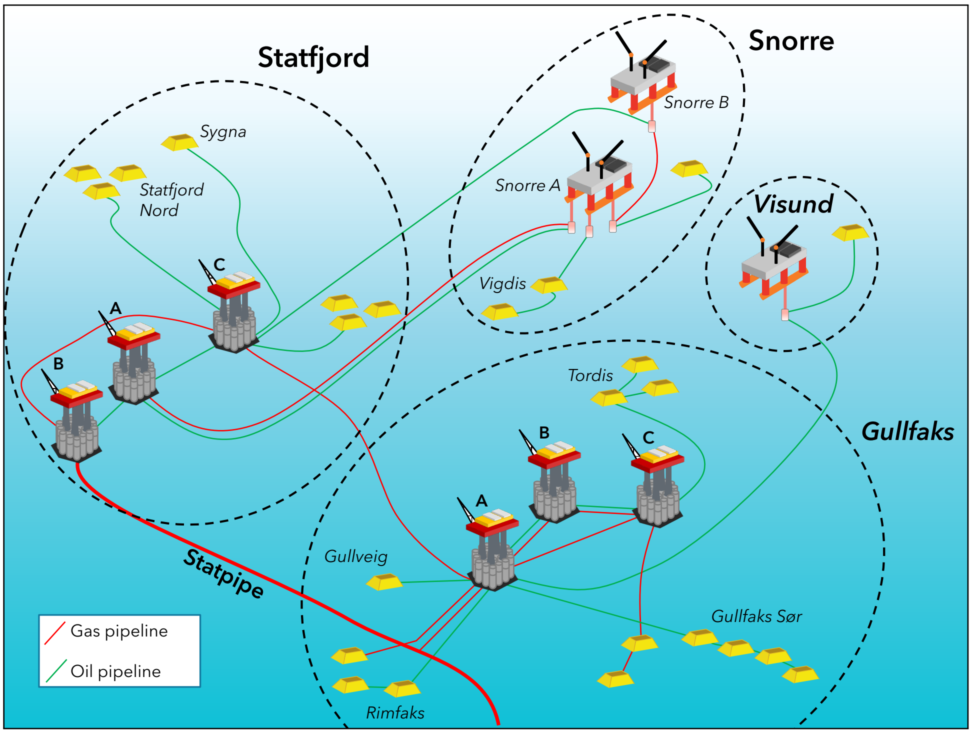


Figure 5: A simplified topography for the Tampen area, where the dotted circles highlight how fields are defined in our phase-out plan, indicated for Statfjord, Gullfaks, Snorre and Visund fields. The illustration is based on an article from SNL ("The Great Norwegian Encyclopedia").

Time horizon for the phase-out plan

We consider the period from today until 2050. As stated in our phase-out plan, we propose that all fields should be shut down before 2050. Although a few large fields (primarily Troll and Johan

Sverdrup) have sufficient resources to produce beyond 2050, we believe that even with current policies there will not be sufficient demand in 2050 to continue production on these fields.

Onshore facilities

The onshore facilities process the oil and gas produced from the fields; this involves the use of both electricity and gas power - which in turn results in greenhouse gas emissions. Complexity and function vary from the LNG plant at Melkøya to the methanol plant at Tjeldbergodden to the oil refinery at Mongstad to the gas processing plants at Kollsnes and Kårstø. What the facilities have in common is that it is difficult to find good historical data on electricity consumption and emissions, and that future electricity consumption and emissions are also difficult to predict - as there are typically many fields producing towards the same onshore facility. The exception is Melkøya - referred to in this report as HLNG (Hammerfest LNG) - where production is linked to one field, and where annual emissions reporting follows the same format and requirements as for the offshore fields.

Due to this complexity, only offshore fields and HLNG will be included in our primary figures and numbers. We nevertheless make approximate assessments of the effects on emissions and electricity consumption related to the onshore facilities in a separate calculation (Chapter 5.5).

2.3 Production forecasts

When drawing up a phase-out plan and assessing its effects, we are dependent on having reliable forecasts for production from the fields. Our starting point is the Norwegian Offshore Directorate's figures for remaining oil and gas reserves for each field. Field lifetimes are obtained from PDOs or other publicly available information. New fields or projects (own PDOs or PDO exemptions) are included from a start-up year obtained from either the Norwegian Offshore Directorate or the operator's own website. The forecasts are then made within this framework using trend analysis. In Appendix II we explain the methodology in further detail.

Validation of forecast data

Our forecasts also cover 2023. At the end of the year, these can be compared with actual production (from the Offshore Directorate's fact pages). The comparison shows a good match:

- Liquid production in the forecast: 1.5% lower than actual production.
- Gas production in the forecast: 1.4% higher than actual production.
- Total in oil equivalents: 0.1% lower than actual production.

2.4 Forecasts for greenhouse gas emissions and electricity consumption

We have also calculated our own forecasts for greenhouse gas emissions and electricity consumption. In MDG's oil network, we have people with detailed knowledge of how Equinor's recently developed emissions and energy calculator (eCalc^{TM}) is constructed, and of the company's best practices for energy and emissions forecasting. Together with historical data on emissions and electricity consumption, we therefore use the following methodology:

1. Retrieve historical data on emissions and electricity from annual reports. We include both methane emissions and emissions from mobile units (typically drilling rigs).

2. Establish a correlation between production and emissions - in this process, you often have to exclude statistical "outliers" due to, for example, revision shutdowns or abnormally high/low drilling activity.

3. Sets a minimum level for emission/power - in most cases we use 2/3 (67%) of average emissions over the last 5 years. This is to model the problem that equipment is designed for early/high production and is rarely replaced to a great extent to operate with equally good energy efficiency in the tail phase, and that some equipment has an on/off mode rather than a linear relationship with volume rate.

4. For planned (PDO-approved) installations (Johan Castberg and Yggdrasil) and power-from-shore projects, we use data from similar fields in operation, as well as an overview Energi & Klima has established based on operators' own estimates of electricity consumption.

5. Planned electrification projects are included both in terms of electricity consumption and reduced emissions from the expected year of implementation.

We also want to analyze the electricity consumption for onshore and offshore use per power region. Unfortunately, this is more difficult than it should be. However, by collecting electricity data from the field-specific annual reports (this became mandatory as of 2020), monthly consumption data for electrical power for mining and oil and gas extraction (there is only one common category), and annual consumption data for electrical power for municipalities for mining and industry, it is possible to present an approximate distribution of the current electricity consumption.

A key concept in the phase-out plan is **emissions intensity**. We calculate this on a year-by-year basis for each field and for the shelf as a whole; it shows how efficiently the fields produce measured in greenhouse gas emissions per unit produced. We have chosen to include methane emissions in our emission forecasts, so we calculate the emission intensity according to the following definition:

$$\text{Emissions intensity} = \frac{\text{Annual greenhouse gas emissions}}{\text{Annual production}} \left[\frac{\text{kg } CO_2e}{\text{barrel o.e.}}\right], \text{ where}$$

CO_2e is CO_2-equivalents and 1 kg CH_4 has a global warming potential (GWP) of 28 kg CO_2e, and

o.e. is equivalents, where 1 000 Sm^3 gas = 1 Sm^3 o.e. and 1 o.e. = 6,3 barrels.

Validation of emissions and electricity consumption data

With our forecast data for production for 2023 (as previously mentioned, less than 1% lower than actual production) as input, our methodology gives us an acceptable match on emissions and electricity consumption in 2023:

- Emissions: 3% higher forecast than reported emissions
- Power from shore (excluding onshore plants other than HLNG): 3.5% higher forecast than reported electricity consumption

Due to changes in regularity and drilling activity, as well as uncertainty in the timing of new power-from-shore projects, both electricity and emission levels vary somewhat from year to year (even given constant production). Therefore, we cannot expect to be more accurate for a single year than we are here.

Exported (scope 3) emissions

We focus mostly on calculating direct (scope 1) emissions and emissions intensity in our phase-out plan. However, we have also included a calculation of the "gross" scope 3 emissions impact of the plan:

$$\begin{aligned}
\text{Scope } 3_{\text{liq}} &= \text{Prod}_{\text{liq}} \times LHV \times \text{Share}_{\text{liq}} \times (1 - NEF_{\text{liq}}) \times EF_{\text{liq}} \\
\text{Scope } 3_{\text{gas}} &= \text{Prod}_{\text{gas}} \times LHV \times \text{Share}_{\text{gas}} \times (1 - NEF_{\text{gas}}) \times EF_{\text{gas}} \\
\text{Scope } 3_{\text{total}} &= \text{Scope } 3_{\text{liq}} + \text{Scope } 3_{\text{gas}}
\end{aligned}$$

Note the following:

- LHV is the calorific value, here we assume – as Equinor – a value of 5.7 GJ/barrel o.e.
- NEF is the fraction not used for energy purposes, here we assume 14 and 10% for oil/liquid (liq.) and gas respectively in 2024, increasing to 21 and 15% in 2050.
- EF are the specific emission factors, here we use 0.072 tons of CO_2e/GJ for oil/liquid (equivalent to 410 kg CO_2e/barrel o.e.) and 0.056 tons of CO_2e/GJ for gas (319 kg CO_2e/barrel o.e.).

2.5 Economic calculations

We calculate government revenues as the sum of taxes and export revenues via the SDFI[4] - i.e., we disregard smaller revenues (these typically amount to a maximum of 5% annually) such as the CO_2 tax and other environmental taxes.

To calculate revenues, we use constant oil and gas prices at the current level, 80 USD/barrel and 4 NOK/Sm^3. We consider this to be conservative/high compared to the calculations from other stakeholders, especially in the long term.

We calculate tax revenues from a simplified model and validate these against actual revenues in recent years.

Costs related to plugging wells are highly uncertain. We have chosen to use SINTEF's estimate (NOK 800 billion), and the study on the UK continental shelf (see table 5-5), which shows that well costs are just under half of total costs. These total costs of around NOK 1 800 billion are then allocated to fields according to a complexity key that includes the type and number of installations and the number of wells.

When assessing cumulative economic effects, we do this by calculating present value. We apply an discount rate of 5 % in these calculations, i.e. the value of a given amount of production in one year is 5% less than the value of the same amount of production in the current year - given a flat price development.

[4] State's Direct Financial Interest (SDFI)

3 Status on the Norwegian continental shelf

3.1 Fields

According to the Norwegian Offshore Directorate's definition of fields, it exists on the Norwegian shelf as of August 2024

- 125 fields that have been in production in total
- 93 fields currently in production
- 32 fields that are closed
- 15 fields under development, where PDO has been approved

In the following sections, the variation between the fields will be described. Any strategy for the Norwegian continental shelf should be based on this variation, because it provides a context for *prioritization*. Important differences include geographic location, duration of production licenses, the fields' total reserves, where the fields are in the production cycle in terms of remaining reserves and lifetime, the distribution between oil and gas, the level of greenhouse gas emissions, and electricity supply – in particular the use of power from shore.

3.2 Production licenses

Licenses for production are regulated in Chapter 3 of the Petroleum Act. Licenses mainly follow this course:

- By virtue of Section 3-9, first paragraph, a license is first granted for an *initial* period, where the purpose is exploration and appraisal. It is common for the licensee to be subject to a "work commitment" during this period (Section 3-8), which may, for example, involve a certain number of exploration wells to be drilled (see Section 13 of the Petroleum Regulations). The duration of the initial period is up to 10 years.

- By virtue of Section 3-9, second paragraph, the licensee is then entitled to an extension of the production license, if the work obligation is fulfilled. As a general rule, this *production period* is up to 30 years, but may in special cases be up to 50 years.

- By virtue of section 3-9, fifth paragraph, the Ministry of Energy may "when indicated by special reasons" extend the permit further. An application for such an extension must be submitted no later than 5 years before the expiry of the permit.

Practice shows that extensions are granted almost routinely, even though the companies are not entitled to them; this is probably motivated by the ministry's assessment of the state's financial interest. Only six of the 34 fields (our field definition) are still in their original production period - for the remaining fields, either all or several of the associated licenses have been extended.

Figure 6 shows the fields' distribution of the current validity of the production licenses. Some fields have several licenses with different types and validity periods; in such fields, the license(s) that contain the most reserves are used. Some fields have licenses that expire before 2030, while some have licenses that run almost until 2050. The fact that very long validity periods have been approved for fields with a low remaining resource base means that the scope for using this tool in the phase-out is smaller than it should be - but it is nevertheless one of several instruments we propose to use.

3.3 Ownership

Petoro manages the state's direct financial interest (SDFI) in the oil and gas fields. The ownership share of the SDFI varies greatly between the fields; some (few) fields have higher than 50%, but

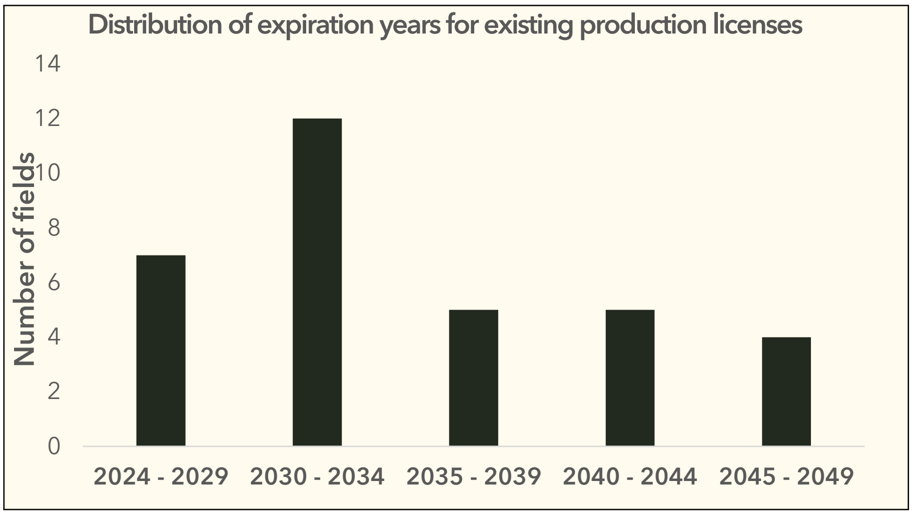


Figure 6: Overview of the distribution of expiration years for existing production licenses for fields on the Norwegian continental shelf, per august 2024. Based on numbers from the Norwegian Offshore Directorate.

there are also a significant number of fields where the state is *not* a direct owner. Through the SDFI, the state covers parts of the investments and operating expenses, and not least the state receives parts of the export revenues. This variation means that the SDFI share is an important factor when calculating and assessing the financial consequences of a phase-out plan. Remaining reserves for the 34 fields that are in operation or PDO-approved are shown in Figure 7. Troll is in a league of its own with 635 million Sm^3 o.e. remaining and a Petoro share of 55%, and has been omitted from the figure to highlight the differences between the other fields. The same applies to Johan Sverdrup, which is also very important with 272 million Sm^3 o.e. remaining and a 17% Petoro share. Other particularly important fields financially for the state are Snøhvit, Heidrun, Oseberg and Ormen Lange.

3.4 Production

Historical production from the Norwegian shelf is shown in Figure 8. Production in recent years has been relatively stable. In 2023, a total of 234 million Sm^3 o.e. was produced, of which:

- 50% gas and 50% liquid (oil, condensate and NGL).
- 75% from fields in the North Sea, 21% from fields in the Norwegian Sea and 4% from fields in the Barents Sea.

Table 2 shows the contribution from the largest and smallest fields to annual production in 2023. For both oil and gas, there are a few fields that make up a large part of the shelf's production, while there are relatively many fields that together do not contribute much. Fields with low production are typically less profitable than fields with high production and are usually late in their lifetime with few remaining reserves.

Table 2: Contributions to annual production (relative share) on the Norwegian continental shelf, by different fields and groups of fields. Based on numbers from the Norwegian Offshore Directorate.

Fields	Troll	Johan Sverdrup	Top 5 fields (agg.)	Bottom 10 fields (agg.)
Total	18 %	19 %	50 %	7,1 %
Oil/liquid	4,0 %	36 %	56 %	6,6 %
Gas	33 %	1,2 %	55 %	0,89 %

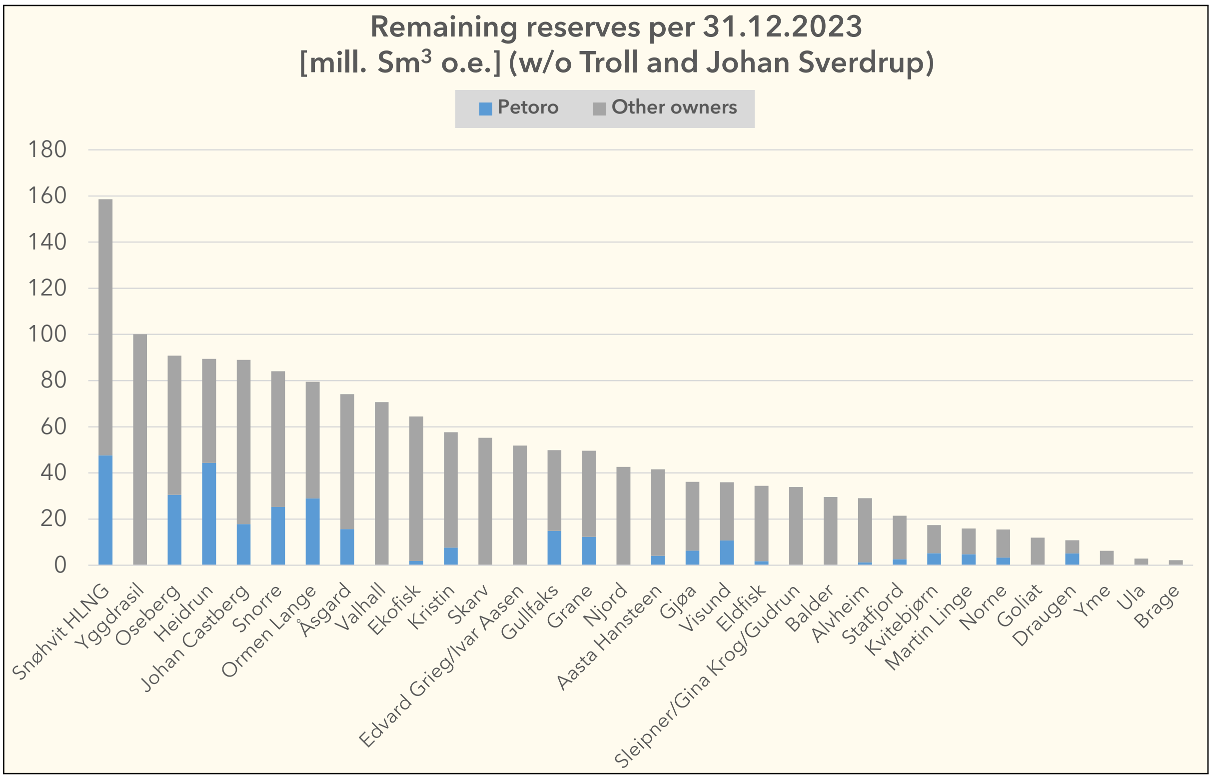


Figure 7: Remaining reserves for fields on the Norwegian continental shelf (in mill. Sm^3 o.e.) by the start of 2024, distributed on ownership shares of Petoro and other owners. Troll and Johan Sverdrup are significantly larger fields and are therefore excluded from the figure to better highlight the variation between other fields. Based on information from the Norwegian Offshore Directorate.

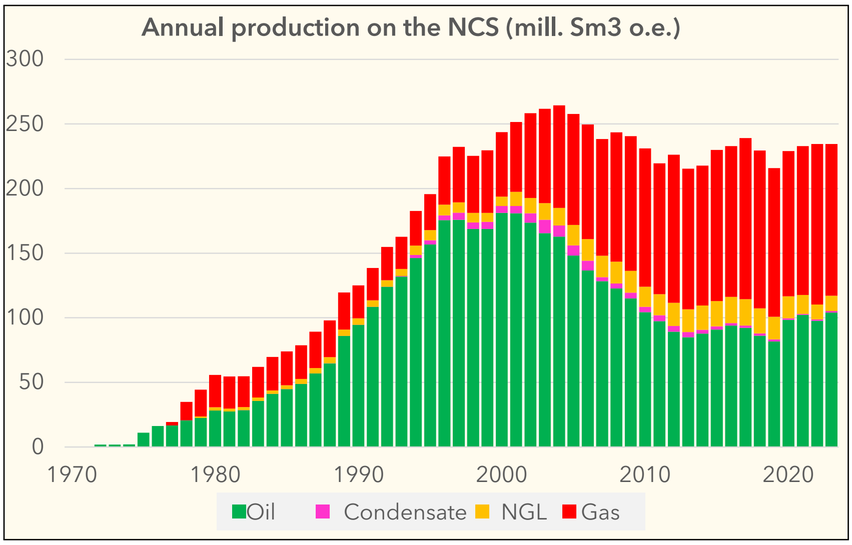


Figure 8: Historical production on the Norwegian continental shelf, based on type of petroleum products (Norskpetroleum.no, 2024).

3.5 Economy

In recent years, due to the war in Ukraine and high energy prices in Europe, Norway has had extraordinarily high revenues from the petroleum industry. By far the two largest sources of income are tax and net cash flow from the SDFI; over the last ten years, these have together contributed an average of 90% of total income. The third largest source of income is dividends from Equinor;

on average 7% of total income. Environmental taxes amount to around NOK 7 billion annually, of which the CO_2 tax is the most important; this corresponds to 0.5 – 5% of the state's total revenues. The development in the government's net cash flow is shown in Figure 9.

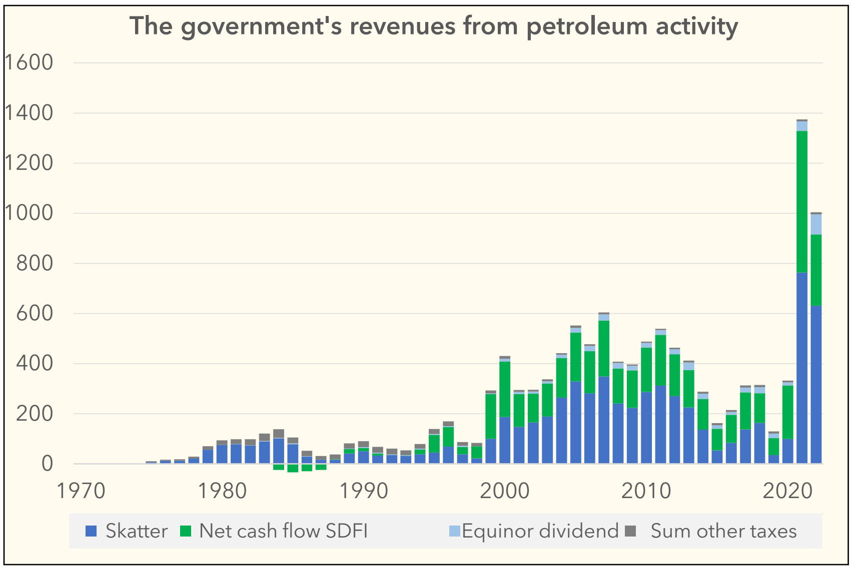


Figure 9: The Government's net annual revenue from petroleum activities on the Norwegian continental shelf, given in billions NOK (2024). Numbers retrieved from Norskpetroleum.no.

On average over the last ten years, the petroleum sector has contributed 24% of government revenues, 19% of GDP and 44% of Norway's exports. In the short term, this picture is expected to be maintained, while in the longer term it is very uncertain; the development of demand and price in Europe is affected by energy and climate policy, technology development and the geopolitical situation. It is important not to equate the current situation with expectations beyond the 2030s. Another important factor in the transition of Norway to a low-emission society, is that the petroleum sector on average (last ten years) has accounted for 19% of investments - these have created and are creating high activity in the short term, but are also locking up a lot of capital and resources that could and should have been used in new, green industries.

3.6 Remaining reserves

According to the definition by the Norwegian Offshore Directorate of petroleum resources, reserves are defined as "*the quantity of petroleum that it has been decided will be recovered*"; this includes fields that are already in production, fields/projects that have an approved PDO, and fields/projects that have been approved by the licensees. It is important to distinguish *reserves* from *resources*, the latter also includes discoveries that have not matured up to the decision/approval of development, as well as undiscovered resources (prospects and exploration opportunities that have not been proven, where discovery probability is included in the estimates).

As already shown in Figure 7, there is great variation between fields when it comes to remaining reserves. Fields with a lot of remaining reserves can continue to generate high revenues for many years to come, but with a long lifetime they are also more exposed to uncertainty in demand and price. In general, it is also the case that profitability decreases and the energy requirement per barrel produced *increases* the lower the proportion of reserves that remain to be produced - in the so-called *tail phase*. In Table 3, the remaining reserves for some key fields and groups of fields are shown, measured against the shelf total. Taking a closer look at the maturity (measured as the proportion of reserves produced out of total available, as of 31.12.2023) for the various fields, we see that there are relatively many fields that have both a low contribution to total remaining reserves, and also have a very low proportion of reserves left to produce. 17 fields (our definition) have between 0-25% share of reserves left to produce. 11 fields have 25-50%, four fields have 50-75% and only two fields have 75-100% of reserves left to produce.

Table 3: Contributions to remaining reserves (relative share) for fields and groups of fields on the Norwegian continental shelf, per 2024. Based on numbers from the Norwegian Offshore Directorate.

Field	Troll	Johan Sverdrup	Top 5 fields (agg.)	Bottom 10 fields (agg.)
Total	26 %	11 %	51 %	5,4 %
Oil/liquid	1,9 %	24 %	50 %	4,6 %
Gas	45 %	0,47 %	69 %	0,57 %

3.7 Exploration and discoveries

Figure 10 shows the development of exploration activity on the Norwegian shelf. Over the past decade, 20-40 exploration wells have been drilled annually, with a discovery success rate of around 50%. Although activity remains high, we have to go all the way back to 2010 and Johan Sverdrup to find a really big discovery. After 2013, annual resource growth has never been higher than 78 million Sm^3 o.e, which corresponds to 1/3 of annual production in 2023. With lower growth than production, even with continued high exploration activity, we will see declining production in the future, which is also confirmed by the Norwegian Offshore Directorate's latest forecasts (Figure 1).

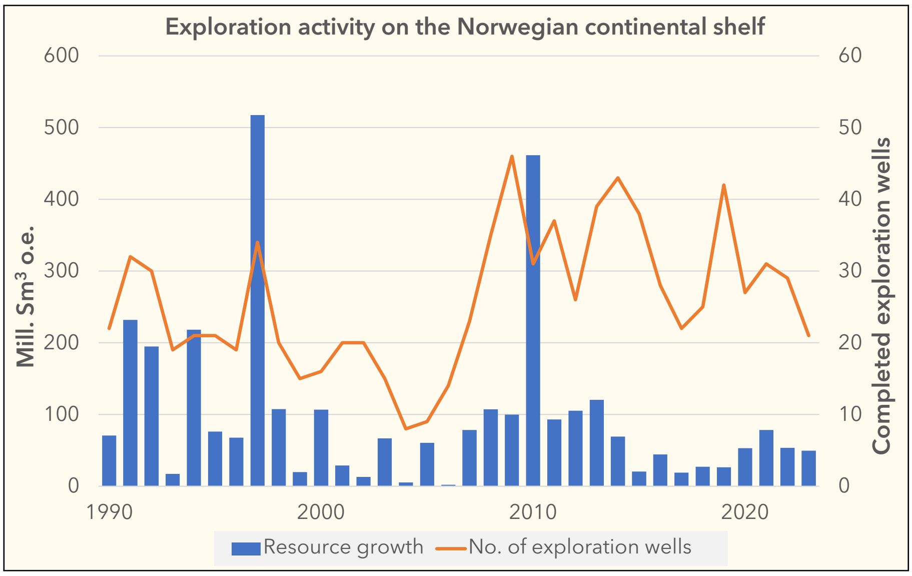


Figure 10: Exploration activity on the Norwegian continental shelf since 1990, illustrated through the total resource growth and number of exploration wells drilled per year (Norskpetroleum.no).

In order to be able to assess possible future value creation from further exploration, it must be taken into account that it takes time to convert a discovery into a field in production. Figure 11 shows this development time for all fields that are either in production, already shut down, or have an approved PDO, and shows that

- Fields that cannot be connected to existing infrastructure typically require 10-15 years from discovery to start of production - there is no clear trend over time.
- Fields that can be linked to existing infrastructure typically require 5-10 years from discovery to the start of production. This has clearly decreased since around 2000.

Development time varies considerably between fields. Fields with low subsurface complexity and subsea/topside technical solutions can often be developed and put into production faster and with higher profitability than fields with high complexity. The data shows no correlation between field size (reserves) and development time.

Although there is great variation, one should have a time perspective of at least 5 years when considering exploration near existing infrastructure, and 10-15 years when considering exploration in new areas - for the start of production. In addition, you need to add the *payback period* that will depend on export revenues and thus oil and gas prices.

Annual exploration costs amount to NOK 20-30 billion, much of which the state has historically covered through the exploration reimbursement scheme. In 2022, the scheme was replaced by a cash flow tax, but companies are still reimbursed most of any annual deficit. Falling demand (see Figure 2) beyond the 2030s could turn what has so far been a beneficial investment for the state into financial losses due to "*stranded assets*" – but the risk is now primarily associated with small companies that are mostly involved in exploration activity, and the risk is reduced compared to the model with an exploration reimbursement scheme.

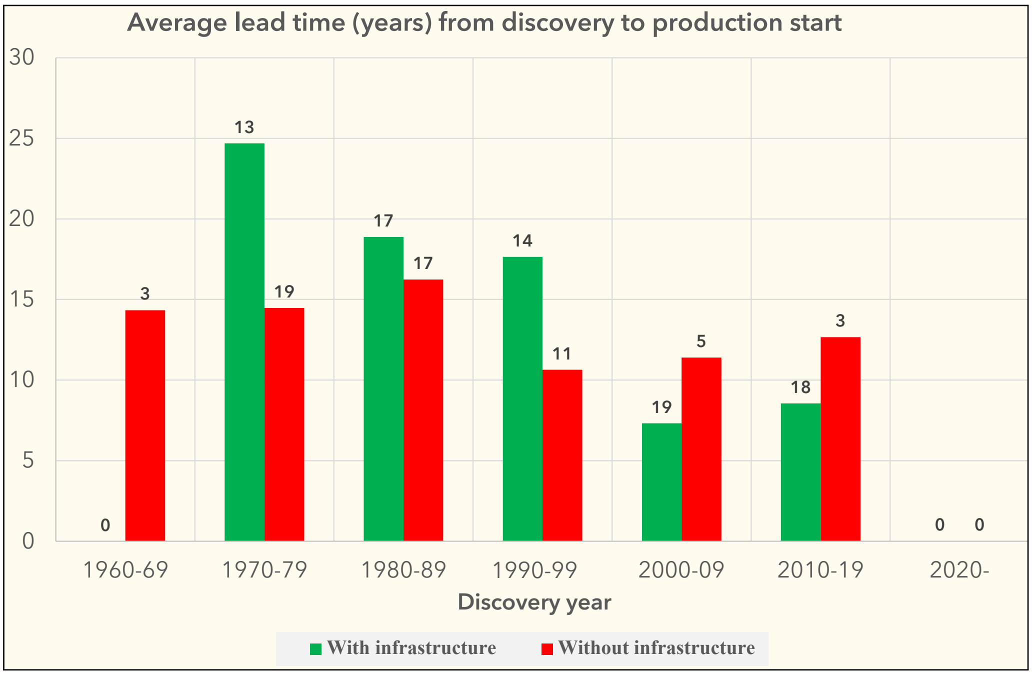


Figure 11: Average lead time from discovery to start of production (in years) for fields on the Norwegian continental shelf either in production, with approved PDO, or fields that have already been shut down. The numbers above each column indicate the number of fields discovered in each decade, and lead time is separated for fields with and without existing ambient infrastructure, respectively. Based on numbers from the Norwegian Offshore Directorate.

3.8 Planned fields

Table 4 shows the fields that have an approved PDO as of August 2024. Johan Castberg and Yggdrasil are new field developments, while the rest of the fields are planned to be connected to existing infrastructure. In addition to new fields, PDOs for power-from-shore projects have also been approved for Oseberg (new), Troll (increase), Valhall (increase), Njord/Draugen (new) and Snøhvit/Melkøya (new).

Despite the narrative from the petroleum industry and the government that Norway must be a stable gas supplier for Europe in the future, a total of only 35% of the reserves for PDO-approved fields is gas - this is primarily due to the fact that Johan Castberg is an oil field without a gas export solution, and that Yggdrasil has a clear predominance of oil. The estimated electricity demand for Yggdrasil and the aforementioned approved electrification projects is approximately 6.4 TWh/year. Yggdrasil alone will require electricity equivalent to approximately 55,000 households annually. Other new fields and field developments that are not electrified will instead lead to an increase in greenhouse gas emissions.

Table 4: Overview of new fields with approved PDO per august 2024 (The Norwegian Offshore Directorate). Reserve volumes given in million Sm^3 o.e.

Field	Planned start	Reserves	Infrastructure	Shore-powered?	Gas share
Johan Castberg	2024	89	NEW	No	0 %
Eirin	2025	4	Gina Krog	Yes	86 %
Halten Øst	2025/2029	15	Åsgard	No	61 %
Tyrving	2025	5	Alvheim	No	<1 %
Verdande	2025	6	Norne	No	16 %
Irpa	2026	21	Aasta Hansteen	No	98 %
Alve Nord	2027	7	Skarv	No	61 %
Idun Nord	2027	3	Skarv	No	89 %
Ørn	2027	10	Skarv	No	90 %
Fenris	2027	25	Valhall	Yes	55 %
Fulla	2027	12	NEW (Yggdrasil)	Yes	75 %
Hugin	2027	38	NEW (Yggdrasil)	Yes	17 %
Munin	2027	50	NEW (Yggdrasil)	Yes	43 %
Symra	2027	10	Ivar Aasen	Yes	12 %
Berling	2028	8	Åsgard	No	61 %

3.9 Greenhouse gas emissions

In 2023, oil and gas extraction in Norway accounted for approximately 11.5 million tons of CO_2e, which corresponds to around 25% of total Norwegian greenhouse gas emissions. This makes it the largest emission sector in Norway.

Gas turbines account for most of the emissions, about 81% in 2022. The turbines are partly used directly/mechanically to drive gas compressors, and partly in conjunction with generators that convert the energy into electrical power, which in turn is used to drive compressors, pumps and other electrical equipment. There is a certain, but not linear, correlation between production level and emission level. The remaining emissions are distributed more or less equally between flaring, boilers and engines; diesel engines are primarily used on mobile drilling rigs.

Approximately 9.4 million tonnes of CO_2e of emissions in 2023 came directly from offshore operation of the fields. The rest is distributed among the onshore facilities, with Mongstad, Kårstø and Melkøya accounting for the majority.

Figure 12 shows the development since 1990 in greenhouse gas emissions from oil and gas extraction, as well as the intensity measured in kg CO_2e per produced barrel (o.e.). Both emissions and intensity have fallen in recent years, primarily due to increased use of onshore electricity. The petroleum industry has a goal of reducing emissions by 50% in 2030 (measured against 2005), but KonKraft says in its latest status report that it will be very difficult to achieve this goal. The report is also clearer than ever that electrification through power from shore is the most important measure, and it puts pressure on the authorities to quickly approve the remaining planned projects.

Today, the average intensity (including emissions from onshore facilities) is approximately 8 kg

CO_2e/barrel o.e.; this is lower than in most other countries. However, it is worth noting that the intensity (only including emissions from offshore facilities and Melkøya, not other onshore facilities) is approximately 12,5 kg CO_2e/barrel o.e. when excluding production and emissions from all fields with onshore power. In other words, the story being told that Norway has particularly "*clean*" production due to low flaring, small leaks and energy-efficient operation does not tell the whole truth, at best.

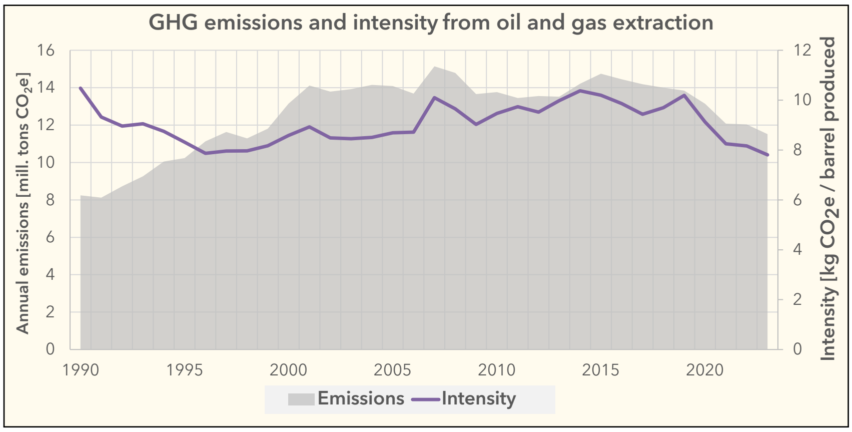


Figure 12: Development in greenhouse gas emissions and emission intensity from the Norwegian oil and gas industry, 1990 – 2023. Data retrieved from Statistics Norway (emissions) and Norskpetroleum.no.

The average emissions intensity for the Norwegian continental shelf hides great variation. In general, fields (that are not electrified) will have increasing emissions the further out in the tail phase they get - this is primarily because equipment (especially gas compressors) is designed for high production and the early production phase, and it is too costly or technically complicated to replace with equipment that is continuously adapted to specifications on production rate and pressure conditions. Another factor is that more energy is required per unit produced in the form of either injection volume (to "reach" small amounts of residual oil) or lower topside pressure (to extract as much gas as possible). Figure 13 clearly shows that fields with little remaining reserves have much higher intensity than fields that have a lot of reserves left to produce. A remarkable number of fields already have an intensity as high as or higher than the world average, which is estimated at 15-20 kg/barrel.

So far, only the direct greenhouse gas emissions have been discussed, i.e., scope 1. However, it is the combustion/final use of oil and gas that causes the greatest emissions – scope 3. In addition, there are emissions associated with the use of energy for extraction – scope 2. Both scope 2 and scope 3 are difficult to calculate, and there is also the discussion of gross vs. net effects.

Net effect of electrification: The gas not used in the gas turbines will instead be exported to Europe. Electrification of the Norwegian continental shelf will most likely still result in a net emission reduction, because the removal of point emissions within the quota market provides incentives to lower the quota ceiling over time, and because gas power plants on the continent are more energy efficient than offshore gas turbines. On the other hand, there is uncertainty about whether increased gas exports will come in addition to other energy supplies, or what they will replace. It is difficult to be quantitative here, but it is clear that the *net* emission effect of electrifying the shelf is *lower* than the gross effect, and that the measure has a high cost per *net* emission reduction globally.

Scope 2: In Norway, the electricity sent to the shelf has a very high share of renewables, and consequently low associated GHG emissions - Equinor estimates in its annual report for 2023 (page 109, location-based scope 2) these emissions to be less than 1% of scope 1 emissions. It is possible to argue for using a "market-based" approach since Norway is connected to the European electricity grid - then scope 2 emissions will be somewhat higher, but still low compared to "scope 1" emissions.

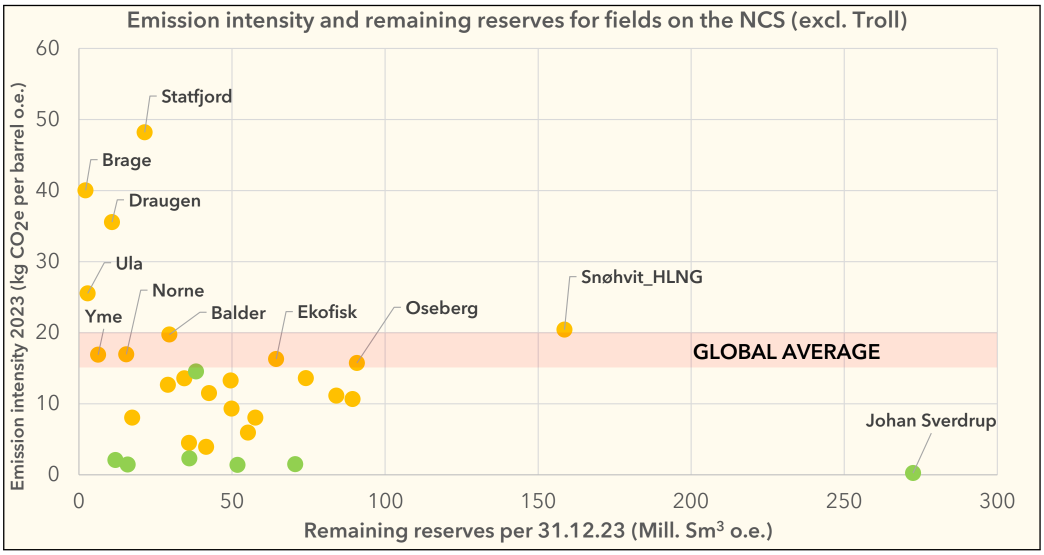


Figure 13: Emission intensity and remaining reserves for the fields (using our definition) on the Norwegian continental shelf. Green fields are powered by electricity from shore, yellow fields are powered by gas turbines only. The Troll field is excluded from the figure due to its huge remaining reserves, but it reported an emission intensity of 2,1 kg CO_2e/barrel o.e. in 2023. Data retrieved from Offshore Norway and The Norwegian Offshore Directorate.

However, both of these variants are only a *gross* assessment. A *net* assessment is complicated, but one should still take into account that electricity is a limited resource and that it has alternative uses. Electrifying yet another platform could mean that a transition project with emission reductions in the onshore industry is not realized.

Scope 3: The gross effect of burning Norwegian oil and gas has been estimated at just over 500 million tons of CO_2e annually – i.e., more than 10 times higher than annual total Norwegian territorial emissions, and about 45 times higher than scope 1 emissions from oil and gas extraction. The *net* effect has been calculated in recent years by Rystad (2023) and Vista Analyse (2023), with different conclusions. In particular, there is disagreement about the demand *elasticity*, i.e., how much demand changes in response to changes in production. However, it is worth noting that none of the reports take into account either the signal effect of the Norwegian phase-out of oil, or the fact that the phase-out will take place gradually over a relatively long period of time - during which the market for fossil fuels will have to change significantly. Nor does it consider which other countries might have to phase out their oil and gas faster if Norway does not take the lead.

3.10 Electricity consumption

Figure 14 shows the consumption of electricity for petroleum extraction in Norway. There has been a marked increase over the past decade, and in 2023 we passed 10 TWh/year for the first time. In addition, we see that the petroleum industry requires an ever-increasing share of electricity production in Norway, approximately 7% in 2023. As mentioned in Chapter 3.8, new power-from-shore projects have already been approved that will increase consumption to around 17 TWh/year in 2030. Power from shore is the petroleum industry's preferred solution for reducing greenhouse gas emissions because it is relatively cheap (compared to other measures) and because it allows a high level of activity to be maintained on exploration and new oil and gas projects. In sum, high use of power from shore leads both to a low rate of conversion on the shelf, and to a lower rate of conversion on shore due to electricity not being available to other industries. We also do not know what the *net* emission effect of electrification is globally.

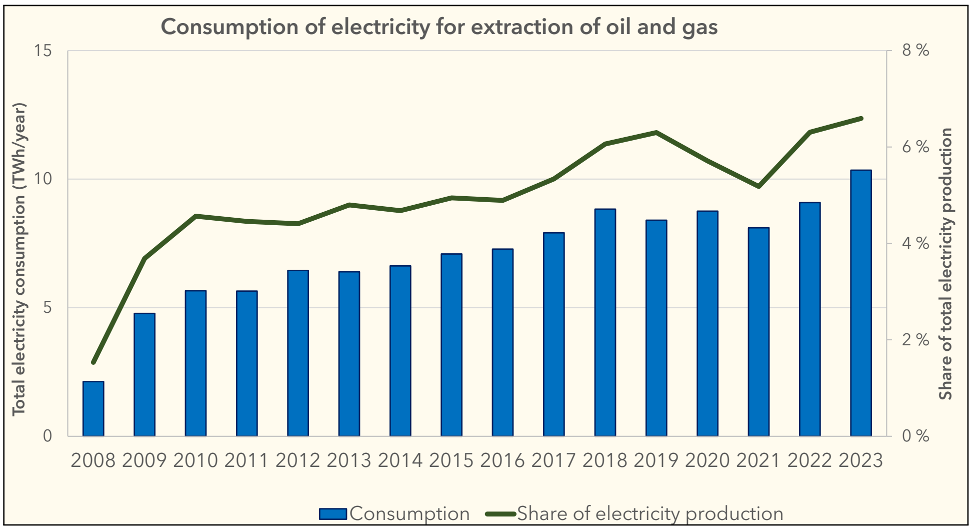


Figure 14: Electricity consumption for oil and gas extraction in Norway since 2008, measured both as absolute numbers (Statistics Norway) and as a relative share of the overall domestic electricity production (Statnett).

Electricity consumption broken down into onshore and offshore per power region is summarized in Table 5 – see comments on methodology in Chapter 2.4. Although the figures are not entirely accurate, it is clear that the load is currently greatest in NO5 and NO2. Both are areas with high electricity production, but transmission capacity is a bottleneck. New, green industry will also be hindered the most in terms of available electricity in these areas. It's worth noting that several of the approved projects going forward will also lead to increased pressure in NO3 (Njord/Draugen) and not least NO4 (Melkøya).

Table 5: Overview of electricity consumption associated with oil and gas extraction and distributed on the Norwegian power regions (2023). Data compiled from Statistics Norway's statistics on annual consumption, region-specific data and statistics on a municipality level.

Power region	Total consumption 2023 [TWh]	Consumption offshore 2023 [TWh]	Connected fields offshore	Onshore consumption 2023 [TWh]	Onshore processing plants
NO1 (East)	0	0	-	0	-
NO2 (South)	2,8	1,4	J. Sverdrup, E. Grieg / Ivar Aasen, Sleipner / Gina K. / Gudrun, Valhall	1,4	Kårstø
NO3 (Central)	1,8	-	-	1,8	Nyhamna, Tjeldbergodden
NO4 (North)	0,8	0,4	Goliat	0,4	Melkøya
NO5 (West)	5,0	1,9	Troll, Gjøa, Martin Linge	3,2	Kollsnes, Sture, Mongstad
TOTAL	**10,4**	**3,7**		**6,7**	

4 The MDG's proposal for a fossil phase-out plan

Based on an adopted resolution from the MDG's national convention 2024, our phase-out plan is based on the following principles:

- **No more exploration or new investments**. This already applies from today.
- **Shutting down fields that are "dirtier" than the world average.** In practice, we shut down fields that reach a higher emission intensity than 15 kg CO_2e/barrel o.e.. Before 2030, we disregard to some extent this limit to allow enough time to plan the closure of the dirtiest fields on the shelf.

- **Say no to lifetime extensions**. Due to the wide range of production license expiry times (see Chapter 3.2), we do not have an absolutely strict interpretation of this - as an example, it does not make much sense to shut down Troll in 2030 when current licenses expire. But we use the expiry time of permits as one of several measures, for fields where the expiry time of the current permit allows for this.
- **Stop all plans for more use of power from shore**. In addition, during the 2030s, we will phase out several fields that are already connected to power from shore to free up electricity for other purposes - when profitability and remaining reserves are significantly lower than today.

In this chapter we present the phasing out of Norwegian oil and gas in several phases lasting five years at a time. The phases are summarized in Table 6, which shows which fields are proposed to be phased out in which phase.

Table 6: Detailed timeline for our proposed phase-out plan. For each phase, the table shows the fields that are proposed to shut down, with their year of production start indicated in parentheses and where the background color indicate the current status for electrification of the fields.

Fase	1 (2024-2030)	2 (2030-2035)	3 (2035-2040)
Fields phased out [Opening year]	Ula [1986]	Alvheim [2008]	Edvard Grieg+ [2015]
	Brage [1993]	Goliat [2016]	Johan Sverdrup [2019]
	Draugen [1993]	Gullfaks [1986]	Valhall [1982]
	Statfjord [1979]	Kvitebjørn [2004]	Yggdrasil [2027]
	Yme [1996]	Aasta Hansteen [2018]	Ormen Lange [2007]
	Balder [1999]	Kristin [2005]	Troll [1995]
	Eldfisk [1979]	Martin Linge [2021]	
	Norne [1997]	Skarv [2013]	
	Ekofisk [1971]	Njord [1997]	
	Sleipner+ [1993]	Oseberg [1988]	
	Snøhvit/HLNG [2007]	Snorre [1992]	
	Åsgard [1997]	Visund [1999]	
		Gjøa [2010]	
		Grane [2003]	
		Heidrun [1995]	
		Johan Castberg [2024]	
Electrification	Partially el.		
Fully electrified	Approved fully el.	Approved partially el.	Partially el. - offshore wind

The overall effect on emissions and annual production (relative to the current level), as well as the number of active remaining fields at any given time, is shown in Figure 15. In the following sections, details from each phase will be presented and described in more detail.

4.1 First phase: 2024 – 2030

In the first phase, up to 2030, all fields with very high emission intensity will be phased out, in line with MDG's previous proposal to the Storting submitted in December 2023. The fields that are phased out first have a minimal impact on revenues from the shelf, but a relatively large impact on emissions. These are also either pure oil fields or fields with a high oil content, so that we can continue to supply Europe with gas in the short term. As we approach 2030, fields with somewhat higher potential earnings will also be phased out - because they still have an emissions intensity

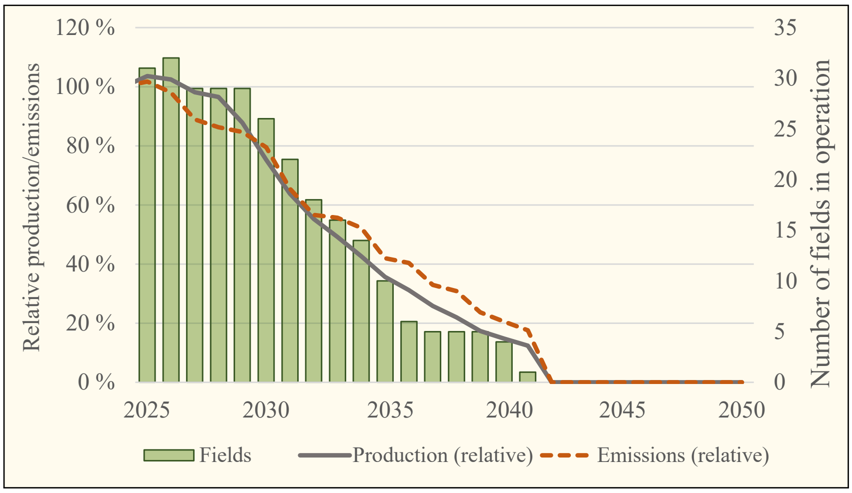


Figure 15: Annual aggregated production and emissions from the Norwegian continental shelf as a result of our proposed phase-out plan, relative to the current levels (100 %). Furthermore, the figure shows the number of fields in production per year towards 2050.

above 15 kg CO_2e/barrel o.e. The vast majority of the fields we propose to shut down before 2030 have already produced for at least 25 years today, meaning that these are old installations and fields.

Draugen has approved power from shore (together with Njord) from 2027, but already today has as little as around 11 million Sm^3 o.e. remaining reserves. Annual electricity demand is estimated to be 0.35 TWh – this will yield a major disturbance to the power balance for Trøndelag county. We therefore propose to shut down Draugen already before 2027, so that the electricity can be prioritized for other purposes in the region.

Snøhvit/HLNG also has approved power from shore, from around 2030. Snøhvit still has significant reserves left to produce, but is currently at around 20 kg CO_2e/barrel o.e. The annual electricity requirement is as much as 3.6 TWh. We suggest shutting down the entire field around 2030, rather than either putting Finnmark county in a very difficult power situation in terms of balance and transmission capacity, or having to dismantle large amounts of untouched nature to produce sufficient electrical power. Secondarily, a solution with carbon capture and storage can be considered.

4.2 Second phase: 2030 – 2035

In the years after 2030, an increasing number of fields, both those operated without power from shore and partially electrified fields, will experience such a large drop in production that their emissions intensity exceeds the global average. It will then no longer be advantageous to continue production from these fields.

In addition, some of the fully electrified fields, such as Goliat and Martin Linge, have such low remaining production that there is a better social benefit in shutting them down and freeing up electricity for other purposes.

We propose shutting down Johan Castberg at the end of this period - even though it will only have produced for about 10 years. Johan Castberg is being developed without power from shore and without a gas export solution, which means that all produced gas must be injected back into the reservoir. This results in a relatively high emissions intensity right from the start, and around 2035 the intensity exceeds the world average. The field does not contribute to delivering any gas to Europe, and without continued exploration and new discoveries in the area, most of the reserves are already produced at this point.

4.3 Third phase: 2035 – 2040

This is the phase in which the remaining fully electrified fields are shut down, as production falls to a level that makes it inappropriate to use large amounts of power from shore to extract the very last of the oil and/or gas. This also applies to the Edvard Grieg, Johan Sverdrup and Yggdrasil fields, all relatively new fields with start-up years later than 2015. Even the giant Yggdrasil development only contains known reserves equivalent to around six months of current production for the shelf as a whole and, according to our forecasts, will have few reserves left as we approach 2040.

The Valhall field is also being shut down - all-electric since 2014, but Valhall is an old field that has undergone several rounds of lifetime extensions since its start-up in 1982.

Ormen Lange produces exclusively gas, but according to our forecasts does not have much reserves left to produce after 2040. The field has a production license that expires in 2041 anyway, and we propose to shut down this field in 2040.

Even after 2040, Troll will have significant reserves left to produce. Although this is also a fully electrified gas field, we nevertheless believe that the starting point must be that Troll is shut down in 2040. If further operation is to be considered after 2040, we believe that this must take place with a zero emission solution - In other words, there will be no emissions from production, transport or use - in Norway or in other countries.

4.4 Relevant policies for implementing the plan

It is a prerequisite **to stop all exploration, as well as investments that result in increased production and/or extended lifetime**. As shown in Chapter 5, this will clearly be the most important instrument in realizing the plan.

Not renewing production licenses is also one of the instruments we propose to use. If other assumptions for demand/price are used, and the importance of emission reductions and restructuring is raised, the threshold for renewing permits will change in relation to the ministry's practice up to now. Since the companies under the law cannot *claim* such extensions (see Chapter 3.2), the state will not risk any form of liability here.

Financial incentives will nevertheless be necessary. Today, fields are only decommissioned when operators consider them unprofitable. By managing the tax policy, we can ensure that this happens in line with the phases in the phase-out plan in two ways:

- The carbon tax (NOK per ton CO_2) must be stepped up significantly compared to current plans. This hits fields that are not electrified, and fields with the highest intensity are hit best.
- A transition tax must be introduced per unit produced. This also affects fields that are electrified, and is therefore an important supplement to the increased carbon tax.

A **support scheme for plugging wells and decommissioning** will help some of the fields to get started earlier with this major job. It is not intended that the state should take over large parts of these expenses, but the incentive should ensure that fields do not extend their lifetime solely for the sake of the present value effects of postponing the decommissioning job (this happens on several fields today).

5 Effects of the proposed fossil phase-out plan

5.1 Production and economy

The production development for the three scenarios "*MDG's phase-out plan*", "*No exploration and investment*", and *"business as usual"*, are already shown in Figure 4. We assess the consequences of our phase-out plan *relative* to the scenario *"business as usual"* - with the assumption that in this scenario there is still sufficient demand in relevant markets so that oil and gas can still be sold profitably in the decades ahead.

Table 7 shows the *possible* accumulated change in production as a result of our phase-out plan, measured against *"business as usual"*. Table 8 shows the *possible* accumulated loss of government revenue, given demand and flat prices. Unfortunately, we do not have sufficiently detailed figures to calculate possible saved costs for the state, in the form of expenses for investments, operations and exploration that are lost if fields become unprofitable ("*stranded assets"*). Overall, the economic estimates must therefore be seen as conservative; in a *worst-case scenario*, the total loss of revenue throughout the period (to 2050) is limited to being in the order of one state budget - or a maximum of 20% of the state's petroleum revenues for the entire period up to 2050.

Costs related to plugging of wells and decommissioning of fields are shown separately in Chapter 5.2.

Table 7: Potential *aggregated* lost production as a result of our phase-out plan, compared to the *"business as usual"* scenario. Note the varying duration of the three time periods all starting from 2024. All numbers given in millions Sm^3 o.e.

Period	"Business as usual"	Our phase-out plan	Change
2024 - 2030	1 610	1 560	-55 (-3 %)
2024 - 2040	3 040	2 180	-900 (-29 %)
2024 - 2050	3 490	2 180	-1 320 (-38 %)

Table 8: Potential *aggregated* reduction of the Government's revenue as a result of our phase-out plan, compared to the *"business as usual"* scenario. Note the varying duration of the three time periods all starting from 2024. All numbers are present values, given in billion NOK.

Period	"Business as usual"	Our phase-out plan	Change (worst case)
2024 - 2030	5 000	4 920	-85 (-2 %)
2024 - 2040	7 800	6 380	-1 420 (-18 %)
2024 - 2050	8 250	6 380	-1 870 (-21 %)

5.2 Field plugging and abandonment costs

With our decommissioning plan, all fields will have to be shut down earlier than in "*business as usual*". This means that decommissioning costs (much of which are covered by the state) will be accelerated, and there is a possible negative net present value effect; we have estimated and summarized this in Table 9. When we get to 2050, the calculations show that this effect is small - some more installations will have to be decommissioned in "*business as usual*" than with our plan, and this effect is approximately as large as the present value effect of earlier termination. With "*business as usual*", most of the decommissioning activity comes after 2040, while with our plan it comes between 2030 and 2040.

Again, it must be stressed that these figures are highly uncertain. However, it is not difficult to imagine that with a "*flatter*" profile for field termination, it will be possible to learn and develop new technology quicker, so that costs related to plugging and abandonment can be lower overall with our plan.

Table 9: Potential *aggregated* overall costs for our phase-out plan associated with plugging and abandonment for fields, compared to a *"business as usual"* scenario. Note the varying duration of the three time periods all starting from 2024. All numbers are present values, given in billion NOK.

Period	"Business as usual"	Our phase-out plan	Change
2024 - 2030	6	220	214
2024 - 2040	80	966	886
2024 - 2050	1 086	1 086	0

5.3 Greenhouse gas emissions

One of the main goals of our decommissioning plan is to reduce greenhouse gas emissions to zero faster than current policy allows. By using emission intensity as an important criterion for which fields are shut down first, we maximize emission reductions while limiting economic consequences. In Table 10, the emission level in different years is compared with the baseline *"business as usual"*, and with the 2023 level. Already in 2035, the emission level is reduced by 88% compared to 2023, and during the year 2040, emissions are reduced to zero.

Table 10: Calculated annual greenhouse gas emissions on the Norwegian continental shelf in our phase-out plan, compared to both a *"business as usual"* scenario and the current emission level (2023), found to be 10,3 million tons of CO_2. As explained in Chapter 2.2, these numbers do not include the onshore facilities except Melkøya/HLNG. The effects of onshore facilities is further discussed in Chapter 5.5.

		Reduction in annual emissions compared to	
Year	GHG emissions	"Business as usual"	2023-emissions
2030	6,4	22 %	38 %
2040	0,2	97 %	98 %
2050	0	100 %	100 %

Figure 16 shows the development in greenhouse gas emissions for our phase-out plan, measured against "*business as usual*" and "*no exploration and investment*". Even in "*business as usual*", emissions are reduced compared to current levels, but keeping many non-electrified fields in operation well into the 2030s and 2040s limits how much reduction can be achieved. A stop in exploration and investments is a very important first step in reducing emissions, but it is clear that active policies beyond this are needed when compared to our plan.

Using the methodology explained in Chapter 2.4 we have also calculated the *gross* effect of scope 3 greenhouse gas emissions, this is shown in Figure 17. It is difficult to quantify the *net* effect of our plan on reducing these emissions, but the order of magnitude shows that the potential to also contribute to global emission reductions outside Norway's borders is great. Accumulated avoided scope 3 emissions (measured against *"business as usual"*) in 2050 are estimated at approximately 2.5 billion tons of CO_2e, or around 55 times Norway's reported emissions for 2023.

5.4 Power from shore

Another important goal of our phase-out plan is to free up electricity for other purposes. Most of the fields that are already electrified with power from shore or have an approved PDO are relatively new fields with high remaining reserves. In addition, there are few (scope 1) greenhouse gas emissions to be gained from shutting down such fields; however, some are/will only be partially electrified (e.g. Sleipner) and therefore also have potential for emission reductions. For these reasons, we primarily prioritize shutting down non-electrified fields first, while fields with power from shore are

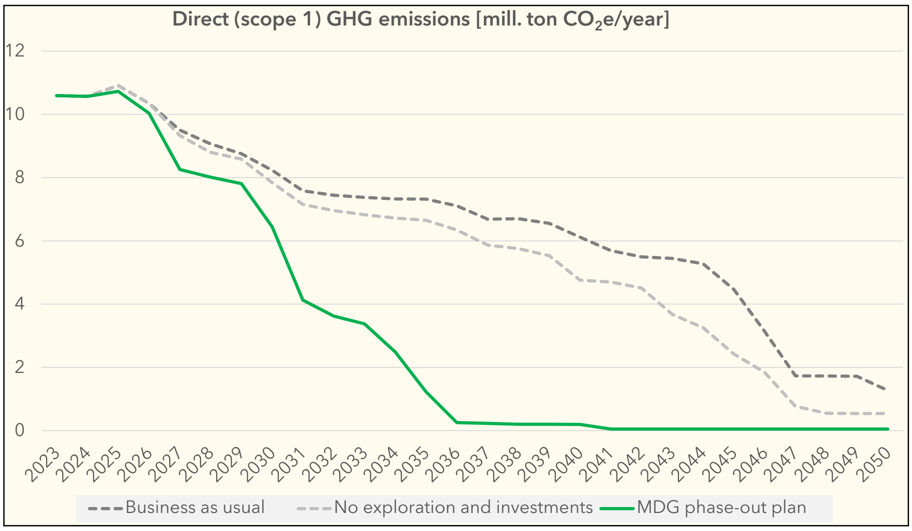


Figure 16: Annual scope 1 greenhouse gas emissions with our phase-out plan, compared to the *"business as usual"* and *"no exploration and investments"* scenarios.

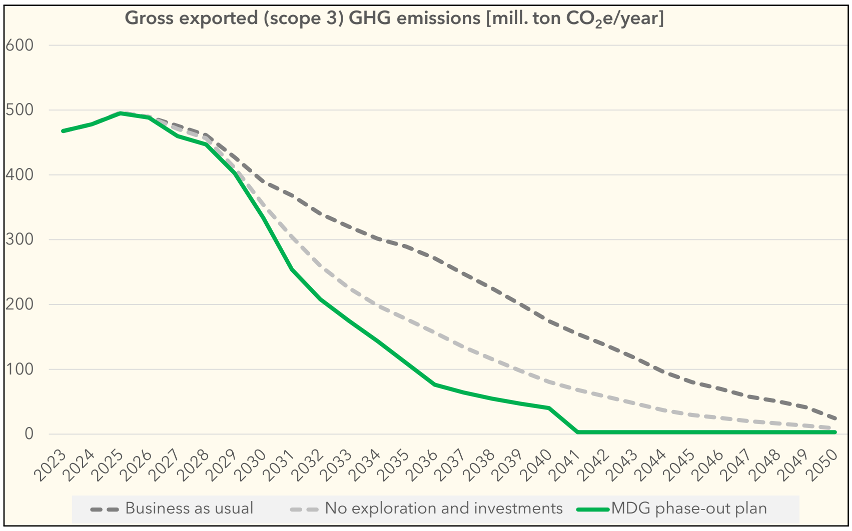


Figure 17: Annual scope 3 greenhouse gas emissions with our phase-out plan, compared to the *"business as usual"* and *"no exploration and investments"* scenarios. Note the magnitude of the emissions compared to the numbers in Figure 16.

largely phased out during the 2030s. Important exceptions are Draugen (planned power from shore 2027) and Snøhvit/HLNG (planned power from shore from 2030) - we propose to shut these down even before the planned electrification date, due to a combination of high emissions intensity (before electrification) and a pressured power situation on shore in Trøndelag and Finnmark counties.

Figure 18 shows the development in the use of power from shore for our phase-out plan, measured against "*business as usual*" and "*no exploration and investment*". In "*business as usual*", a significant increase in electricity consumption is expected, especially due to the planned electrification of HLNG in 2030. In 2040, expected electricity consumption is approximately 15 TWh/year. No exploration and investment helps somewhat beyond the 2030s by avoiding even more power-from-shore projects and extending the lifetime of already electrified fields. But as with greenhouse gas emissions, it's clear that tighter policies beyond stopping exploration and investment are needed to truly release greater amounts of electricity.

In our phase-out plan, we will release 12 TWh/year in 2040 measured against "*business as usual*".

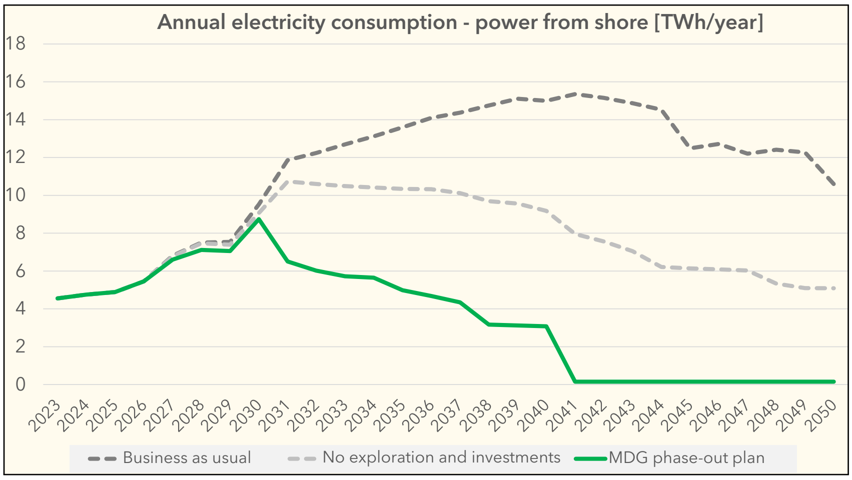


Figure 18: Annual consumption of electricity from shore in our phase-out plan, compared to the scenarios *"business as usual"* and *"no exploration and investments"*. As explained in Chapter 2.2, these numbers do not include the onshore facilities except Melkøya/HLNG. We account for these effects in the discussion presented in Chapter 5.5.

5.5 Effects from onshore facilities

As explained in Chapter 2.2 , the results so far are presented *without* effects on the onshore facilities (except Melkøya/HLNG), due to the complexity and uncertainty that comes with analyzing the onshore facilities. It is nevertheless possible, based on the methodology explained in Chapter 2.4, to estimate additional effects on emission reductions and electricity consumption from our plan. This is shown in Figure 19 (greenhouse gas emissions) and Figure 20 (electricity consumption).

Beyond the 2030s, our plan makes it possible to shut down some of the smaller onshore facilities, i.e. those that are not linked to very many fields. However, it's not until 2040 and beyond that the extra effects on emissions from the onshore facilities really pay off - when they can be shut down completely. We see the same picture for the consumption of electrical power; after 2040, shutting down the onshore facilities will free up a lot of electricity that can be used for other purposes.

5.6 Impact on employment

With an expected decline in production in the future, the number of jobs associated with the oil and gas industry will also decrease. In *Perspektivmeldingen 2021*[5], a fall of 50,000 jobs is estimated up to 2030 (adjusted in *Perspektivmeldingen 2024* to a reduction of 35,000 from 2024 to 2030, and a further 70,000 from 2030 to 2060), but it is also pointed out that in the event of a sudden drop in oil prices, 90,000 jobs could disappear.

In June 2023, the Norwegian Committee on Skill Needs, *Kompetansebehovsutvalget*, launched its report on future skills needs and challenges for transforming Norwegian business and industry, stating that we lack the skills needed to succeed in the transition. There is a shortage of skills and specific professional knowledge, and increasing competition between industries for the same heads and hands. As part of the committee's knowledge base, NIFU and SINTEF in a separate report summarized their review of the business community's needs based on achieving established climate and environmental goals. They find that "*the petroleum industry employs many of the people who are also expected to be needed more as a result of a green transition across the whole of working life*". If we are

[5] Long-term Perspectives on the Norwegian Economy, presented by the Ministry of Finance

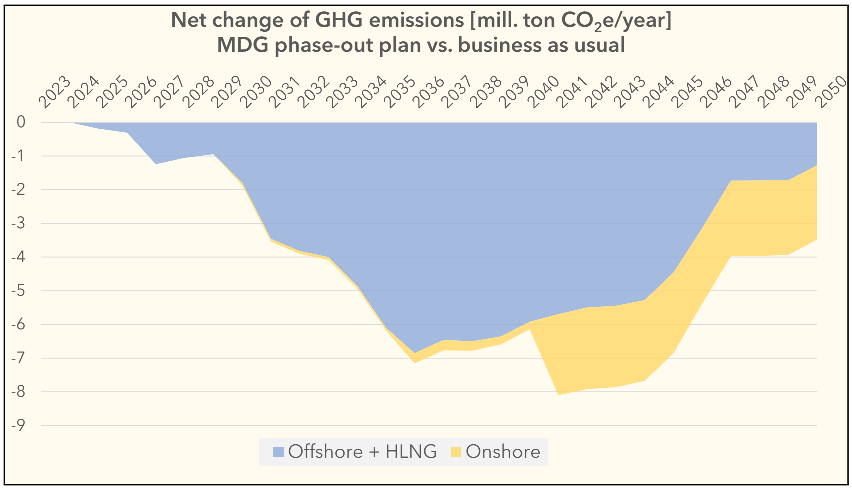


Figure 19: Reduced greenhouse gas emissions in our phase-out plan compared to the *"business as usual"* scenario. The figure also highlights the potential additional effect on the greenhouse gas emissions due to the shutdown of onshore facilities.

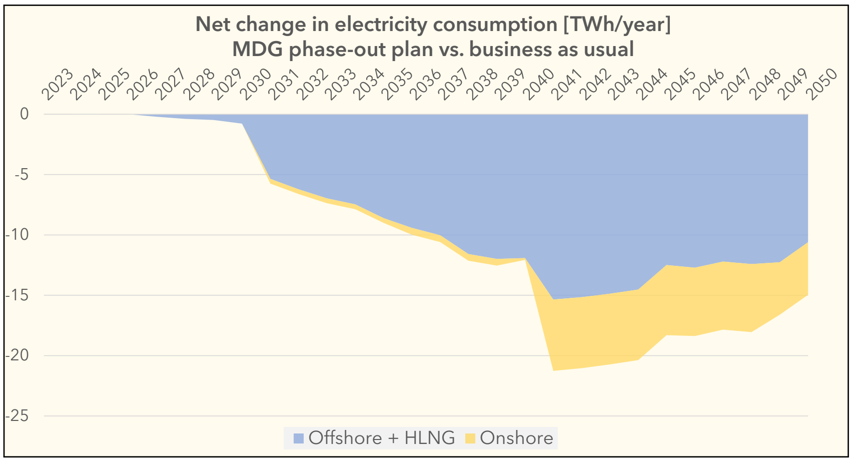


Figure 20: Reduced electricity consumption in our phase-out plan compared to the *"business as usual"* scenario. The figure also highlights the potential additional effect on the electricity consumption due to the shutdown of onshore facilities.

to increase the pace of the transition, we must free up resources that are currently tied up in the petroleum industry. Perspektivmeldingen 2024 concludes that "*a gradual decline in activity in the oil and gas industry will not create challenges in the form of long-term increased unemployment, because the workforce will be in demand elsewhere*" (**our translations**).

In its report Utfordringer for lønnsdannelsen og norsk økonomi[6] (2023), Statistics Norway calculates the consequences of the Norwegian Offshore Directorate's scenario with low resource growth/no technological development (see Figure 1), and finds that the petroleum industry and associated services will need to employ approximately 15,000 more people in other industries. The report *Rettferdig, grønn omstilling* ("Fair, green transition") by Samfunnsøkonomisk Analyse) launched in April 2024 presents estimates of the effects of a low-emission scenario in which there is an immediate halt to all new exploration for oil and gas and a controlled phase-out of all petroleum production by 2050. Compared with a reference scenario that is similar to the expectations scenario of the

[6] Translates to "Challenges for salary determination and the Norwegian economy"

Norwegian Offshore Directorate (see Figure 1), it is found that in the period up to 2050, around 27,000 people will need to be retrained. In this report, the authors also point to the great need for expertise in other industries and that the transition at a national level will be able to take place without major challenges, but they also point to the risk of regional vulnerability in local communities and municipalities where the petroleum industry (and especially the supplier industry) accounts for as much as 10-15% of total employment. This is typical for some coastal municipalities in Western Norway. We therefore propose setting up local transition commissions where relevant stakeholders can contribute knowledge about local conditions and propose measures to counteract these temporary challenges.

Predicting the consequences for employment in the petroleum industry and other industries as a result of a change in oil policy is a demanding exercise. Nonetheless, all available analyses indicate that with a controlled phase-out of petroleum activities on the Norwegian continental shelf over a moderate time horizon, we will avoid increased unemployment and be in a far better position to accelerate the restructuring of Norwegian business and industry than with a "*business as usual*" approach where we lose industrial opportunities to other parts of the world and at the same time run the risk of new, abrupt changes in the market situation due to a fall in oil and/or gas prices. MDG's policy also builds up green industries, which will increase the opportunities for current petroleum employees to find another relevant job.

Appendices

I Detailed field overview

Table 11: Full overview of the existing fields on the Norwegian continental shelf, included Johan Castberg (2024) and Yggdrasil (2027), highlighting the large variety in terms of annual production volumes, reported greenhouse gas emissions and corresponding emission intensity, as well as the electricity consumption and estimated remaining reserves per 31.12.23.

Field (our definition)	Production 2023 [mill. Sm3 o.e.]	Emissions 2023 [mill. tonn]	Intensity 2023 [kg CO2 per fat o.e.]	Shore power 2023 [TWh]	Remaining reserves [mill. Sm3 o.e.]
Aasta Hansteen	7,1	0,18	3,9	-	42
Alvheim	2,8	0,23	13,0	-	29
Balder	1,3	0,16	20,0	-	30
Brage	0,8	0,20	40,0	-	2
Draugen	0,9	0,20	36,0	-	11
Edvard Grieg & Ivar Aasen	7,9	0,07	1,4	0,33	52
Ekofisk	5,5	0,57	16,0	-	64
Eldfisk	3,0	0,25	14,0	-	34
Gjøa	8,4	0,12	2,3	0,36	36
Goliat	1,5	0,02	2,1	0,41	12
Grane	2,6	0,22	13,0	-	50
Gullfaks	9,9	0,58	9,3	-	50
Heidrun	5,2	0,35	11,0	-	89
Johan Castberg	-	-	-	-	89
Johan Sverdrup	43,0	0,07	0,3	0,63	270
Kristin	5,7	0,29	8,0	-	58
Kvitebjørn	3,8	0,19	8,0	-	17
Martin Linge	3,2	0,03	1,4	0,22	16
Njord	2,4	0,18	11,0	-	43
Norne	2,5	0,27	17,0	-	15
Ormen Lange	7,0	-	-	-	79
Oseberg	11,0	1,10	16,0	-	91
Skarv	9,5	0,36	5,9	-	55
Sleipner, Gina Krog & Gudrun	8,1	0,74	15,0	0,05	38
Snorre	6,5	0,46	11,0	-	84
Snøhvit / HLNG	6,9	0,89	20,0	-	159
Statfjord	2,4	0,72	48,0	-	21
Troll	43	0,58	2,1	1,30	640
Ula	1,1	0,18	26,0	-	2,9
Valhall	3,2	0,03	1,5	0,39	71
Visund	6,6	0,19	4,5	-	36
Yggdrasil	-	-	-	-	100
Yme	1,1	0,12	17,0	-	6
Åsgard	9,5	0,81	14,0	-	74
TOTAL	**234**	**10,3**	**7,0**	**3,7**	**2 460**

Notes:

- Emissions and electricity consumption at onshore facilities (excluding Melkøya/HLNG) are not included.
- Ormen Lange has been developed exclusively with a subsea solution; emissions and power consumption are therefore associated only with the onshore facilities and these are consequently not included.
- Consumption of power from shore, emissions and intensity will all be affected by PDO-approved projects for (increased) electrification with power from shore.
- The intensity of non-electrified fields will generally increase over time as production declines.
- Remaining reserves are colored by proportion of oil vs. gas: Fully green is oil and liquids only, fully red is gas only.

II Description of method for estimating production forecasts

The following is a description of the method used to make forecasts for fields in production on the Norwegian shelf. It must be emphasized that the method is a simplification of reality, but is based on knowledge of typical life cycles for fields of different size and character, as well as publicly available information on remaining reserves and estimated lifetimes. The method is illustrated with two fields of different types, and is applied to the remaining fields to create the aggregated production forecasts shown in Figure 4.

Mature field with little new resource growth: Snorre

Most fields on the Norwegian continental shelf are relatively old and have "plateaued", a term that describes that production has begun to decline after being stable at a peak level (plateau) of production for a period of typically 7-10 years. For a field like Snorre, which started production in 1992, this is clear, as shown in Figure 21a for the historical production of oil on the field. Although it is not always trivial to define the time period in which "plateau production" takes place, we choose here to use the period 1998–2004.

For further production on the field, we use an assumption that all production will follow a general S-curve (Richard's curve), where production in a given year t after a reference year with $t = 0$ is given as

$$P(t) = A + \frac{K - A}{(C + Qe^{-Bt})^{1/\nu}},$$

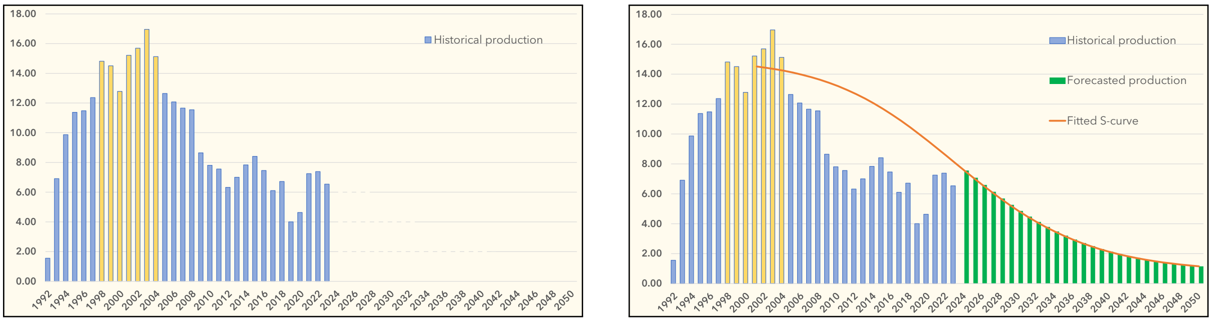
which is a general formula for such curves where $A, B, K, Q, C,$ and ν are constants. A and K define the start and end levels (limits) for very low and high time values. We measure the production relative to the plateau production, so that $A = 1$ expresses the maximum production and $K = 0$ represents the end of the production period.

Furthermore, it must be ensured that the total production (given as *integral* under the curve) in the remaining lifetime of the field, corresponds to the estimate of remaining reserves given by the Norwegian Offshore Directorate. For Snorre, it is stated that there are 84.1 million Sm^3 o.e. remaining oil reserves as of 31.12.2023. The remaining lifetime of such fields can be difficult to obtain information about, so in cases where such information is lacking, we make forecasts up to 2050.

If we define the reference year $t = 0$ for the first year of plateau production, i.e. in 1998, the forecast value for 2024 will correspond to the value for P when $t = 26$, and for the last year of production the time value will be $t = 52$. In other words, we must ensure that the curve fit gives the integral

$$\int_{26}^{52} P(t) = 84.1 \cdot 10^6 Sm^3 \text{ o.e.}$$

The curve illustrated in Figure 21b meets these requirements, and the production volumes year by year are as shown. It is clear from the historical data that production cannot be expected to follow an idealized curve, and variations in production will occur as a result of, among other things, turnarounds, tie-in of new satellite fields, new projects and wells. However, when the sum of remaining production matches the Norwegian Petroleum Directorate's estimate of remaining reserves, we believe that the margin of error is acceptable over time, especially since the purpose of these forecasts is to be able to discuss the effects of the decommissioning plan at an aggregated level for the shelf as a whole.



(a) Historical production at Snorre (oil)

(b) Forecasted future production at Snorre

Figure 21: Historical and estimated future production (given in mill. Sm^3 o.e.) towards 2050 in the scenario with no exploration and investments, based on curve fitting and details regarding lifetime and remaining reserves. The plateau production is indicated with yellow bars, and we assume that it consists of the period 1998–2004 for the Snorre field.

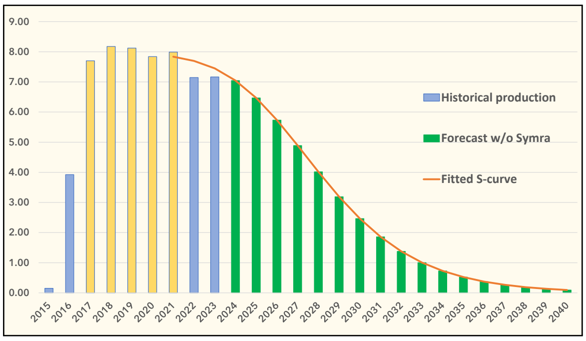
Existing, young field with tie-ins of new discoveries: Edvard Grieg/Ivar Aasen

A similar approach has also been applied to newer fields that are still in the period of plateau production, illustrated here with the field (using our definition) consisting of Edvard Grieg, Ivar Aasen and other satellite fields associated with these platforms. However, some additional assumptions must be made here compared with the example for Snorre - we assume that production starts to decline when half of the total reserves in the field(s) have been recovered. For Edvard Grieg/Ivar Aasen, this milestone was passed in 2023, indicating that the field will plateau and the reduction in production will start in 2024. However, according to the overview in Table 4, new production will be added through the connection of the Symra field from 2027. We take this into account through the following two steps:

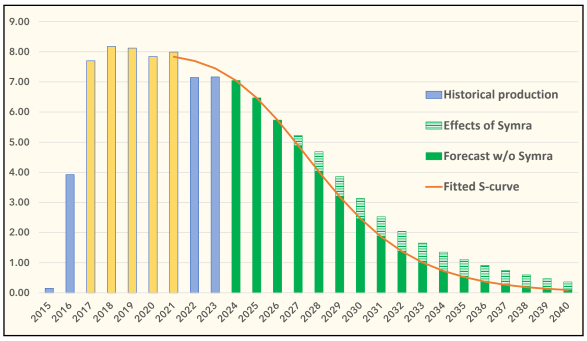
1. We calculate a separate forecast for the remaining reserves in the Edvard Grieg and Ivar Aasen fields (without the effect of Symra)

2. We assume that production at Symra follows the same development as for the two above-mentioned fields, from the time it opens until the end of the field's lifetime around the mid-2040s.

The curve fitting is done in the same way as in the example for Snorre, but the parameter values for B, Q and ν, which are shape parameters for the curve, will naturally change. We then end up with a forecast for existing reserves for Edvard Grieg/Ivar Aasen as shown in Figure 22a, and for the field as a whole including Symra from 2027, as shown in Figure 22b.



(a) Forecast for existing fields in operation



(b) Forecast including the connection of Symra

Figure 22: Historical and estimated future production (given in mill. Sm^3 o.e.) for the Edvard Grieg/Ivar Aasen field in the scenario with no exploration and investments, based on curve fitting and information regarding the lifetime and remaining reserves. The effect of connecting a new field (Symra) to the existing field infrastructure is shown, and the estimated aggregated production corresponds to the overall estimate for remaining reserves for the fields included in our database.

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