WHEN TRUST MATTERS

OG21 study: Low carbon solutions

Pre-read for OG21 workshop

13 June 2022

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1. Introduction

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1.1 Background

Meeting the GHG emission reduction targets require further measures

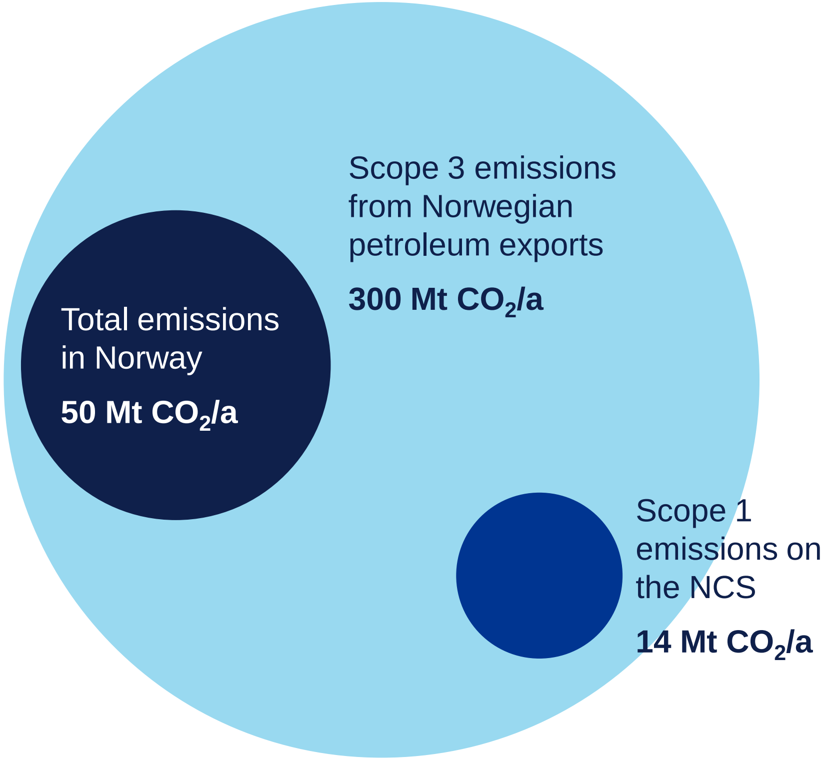
The Norwegian oil and gas industry has committed to reducing its scope 1 greenhouse gas (GHG) emissions by 50 percent in 2030 compared with 2005, and near-zero in 2050. Moreover, there is increasing focus on decarbonizing the whole petroleum value chain – the scope 3 emissions from petroleum exports are around 6 times higher than the total emissions in Norway today.

One main measure to meeting the 2030 emission reduction target is electrification from shore. However, a wide-scale electrification of all sectors in Norway in addition to increasing demand from new industries is expected, and studies show that investments in grid capacity and power production may not be sufficient to meet the demand. This imbalance, alongside the current landscape with high consumer electricity prices, has caused a heated political debate on how the power grid should be developed and whether the Norwegian Continental Shelf (NCS) should be electrified from shore.

Considerable efforts are now made in developing alternatives for reducing emissions on the NCS, such as electrification from offshore wind, offshore CCS and low-carbon fuels for gas turbines, as well as looking into synergies with scope 3 emission reductions. However, current maturity, plans and adoption pace do not suggest sufficient scale by 2030. As such, there is a need to investigate whether further measures can be taken to accelerate technology development and implementation in the coming years.

Norwegian emissions – the big picture

Source: LowEmission research centre



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1.1 Background
A holistic approach is important to enable accelerated implementation

The Norwegian petroleum sector will only reach the ambitious targets when great care is given to not only understanding the technological solutions at hand and the emissions reduction potential they offer, but also when and how technologies will be commercially viable. Such a holistic approach will lead to a successful plan on which technologies should be applied when, while being aware of specific obstacles for implementation upfront. The result of such planning should be a framework for operators that enables an accelerated uptake of the technologies, mostly driven by market acceptance and uptake as they see it as an opportunity, rather than regulatory push.

Moreover, it is important to view the possibilities in light of recent market developments and energy policy. Most notably, the Ukrainian war has made EU determined to become independent of Russian gas by increasing developments of renewables, accelerating green hydrogen and securing supply of natural gas from other sources. This impacts the Norwegian energy politics in several ways:

- The timeline for natural gas from the NCS in its traditional form may be extended.
- The incentive for blue hydrogen is more unclear. With Europe in direct need of natural gas and gas prices still spiking, the question is whether significant amounts of natural gas will be available for producing blue hydrogen.
- The acceleration of renewables and push for offshore wind in Europe provides an opportunity for Norway and the NCS to take a leading role in industry developments, but we need to act fast.
- With energy prices expected to continue at a high level in the coming years as well as the Norwegian power surplus approaching zero, the debate on whether to electrify the NCS from shore will likely continue.

1.2 Purpose and objectives of the study

Purpose: By the end of this project, OG21 has described realistic ways to accelerate technology implementation required to meet the GHG emission reduction targets.

Objectives:

- Obtain a thorough understanding of potential GHG emission reduction technologies, their technical and commercial readiness levels, application scope and scaling, and development and implementation obstacles.
- Identify measures and actions that could be taken to accelerate development and implementation of the most promising GHG reduction technologies with respect to GHG reduction volumes, scaling, and implementation timeline.
- Describe the business opportunity for the Norwegian state as well as for Norwegian industry enterprises in taking a leadership role in petroleum decarbonization solutions (Scope 1, 2 and 3 emissions).

Desired outcome: The findings from this report will play an important part in ensuring OG21 can describe realistic ways to accelerate the technology implementation required to meet the GHG emission reduction targets, as well as how Norway can take a leading role in emerging industries and petroleum decarbonization by ensuring our world leading petroleum companies and solutions provide a competitive edge.

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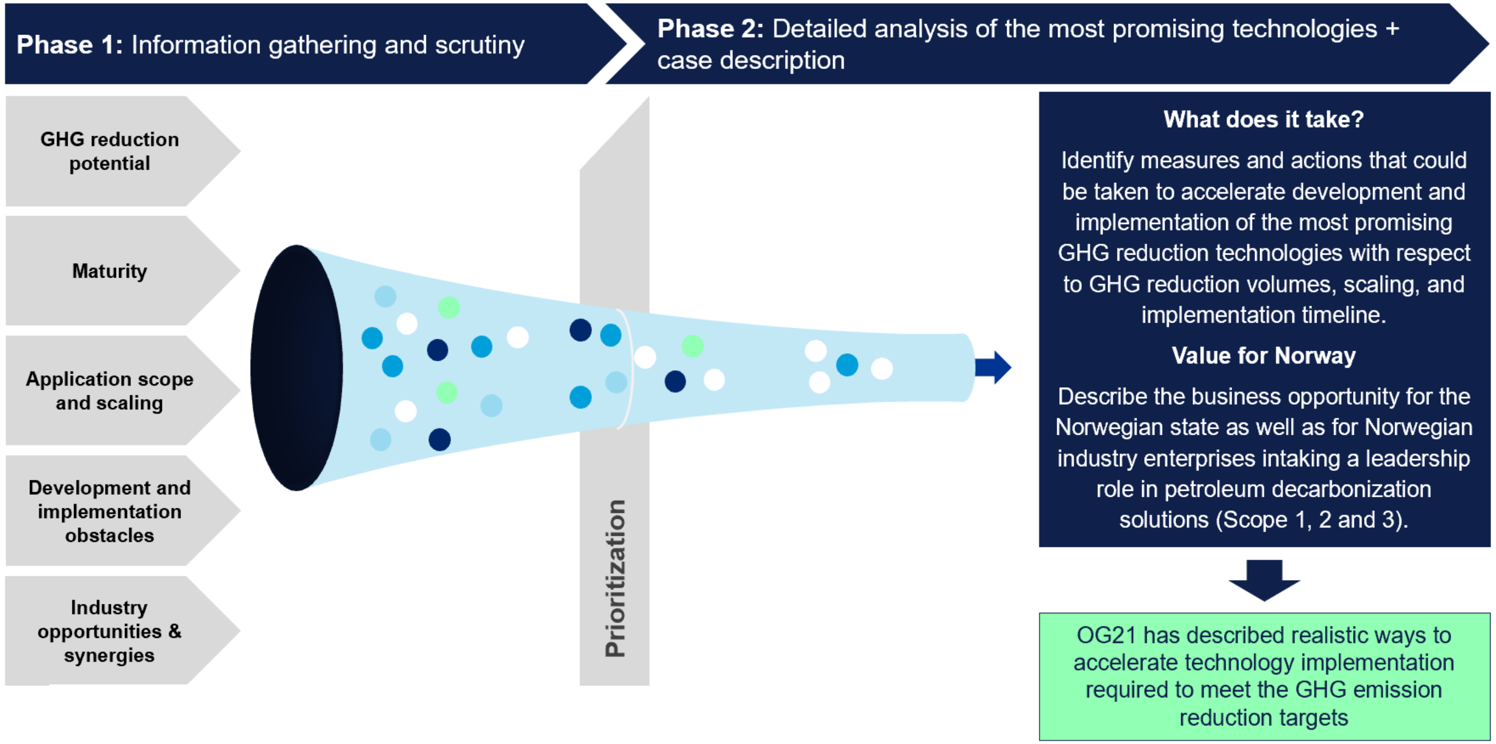
1.3 Approach
The study consist of several steps in order to identify the most promising opportunities

The study is performed in two phases, as seen in the figure.

In Phase 1, a set of decarbonization technologies are described on a high level based on chosen screening criteria. The technologies are further discussed in half-day workshops with all technology groups (TG's) in OG21. This provides us with a solid foundation for prioritizing and agreeing on a short-listed group of technologies that go into Phase 2.

In Phase 2, a more detailed analysis is done of the chosen technologies, including case studies. As part of this phase, we will identify important measures for accelerating development and implementation of the most promising opportunities ("What does it take?"), as well as describe the business opportunities for the Norwegian state and industry ("Value for Norway").

Together, this will provide OG21 with a solid basis for describing realistic ways to accelerate technology implementation required to meet the GHG emission reduction targets.



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1.3 Approach
Ensuring consistency between emission sources

- The GHG emission reduction targets for the NCS refer to the scope 1 emissions. As such, in order to ensure clarity and consistency, we distinguish between scope 1, scope 2 and scope 3 emission reduction opportunities in this study.
- **Scope 1 opportunities/technologies:** Quantitative assessment of GHG reduction potential and scaling – what will it take to meet the targets?
- **Scope 2 opportunities/technologies:** Scope 2 emissions are assessed alongside scope 1 opportunities.
- **Scope 3 opportunities/technologies:** More qualitative assessment and top-down approach on the reduction potential and scaling of most important technologies – how can Norwegian petroleum industry stay competitive and ahead of the responsibility trend by influencing indirect emissions?

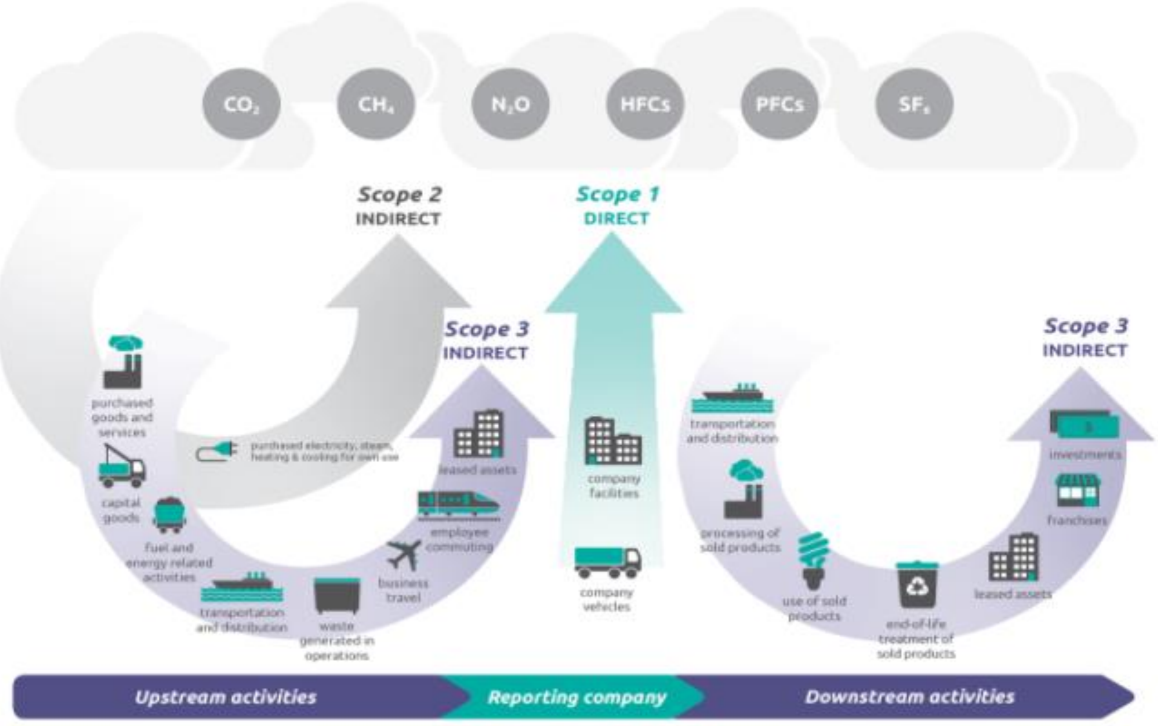

Figure: GHG Protocol

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1.4 Introduction to scope 1, 2 and 3 emissions

Overview

Historically, the emphasis of measuring a company's carbon footprint has been to measure direct emissions in the form of scope 1, as well as indirect emissions that are more easily influenced in the form of scope 2. Solid documentation on what Scope 1 and 2 emissions, and strategies to reduce them, are increasingly expected from stakeholders. This type of reporting has long been a feature of non-financial reporting requirements and features in most companies' sustainability reporting.

That said, scope 1 and 2 reporting falls short of capturing the full carbon footprint of a company, as it does not reflect the full indirect emissions throughout the value chain. As stakeholders have become increasingly aware of that scope 1 and 2 emissions are not accurately reflecting a company's real carbon footprint, the focus on scope 3 emissions have picked up. **For the oil and gas industry, this is notably in the form of emissions stemming from the use of sold products downstream in the form of oil and gas**. The logical extension to this realization would be that similar pressures intensify on countries exporting their emissions. In Norway's case, this would be in the form of the scope 3 emissions associated with the use of exported oil and gas downstream.

For corporates and countries, declining scope 1 and 2 emissions can reflect an effective decarbonization strategy within these boundaries. That said, if considered in isolation, such a focus is likely to conceal the full value chain carbon footprint of an activity. For full transparency on sustainability impacts, all three scopes are expected to be captured in order to reflect the true negative externalities of a company's (and country) across its value chain. Corporates are already feeling this squeeze, and it may be prudent to take such considerations into account at the national level in order to bolster the long-term international competitiveness of Norwegian companies and safeguard their sustainability credentials.

Scope 2: Captures indirect GHG emissions from purchased electricity, heat, cooling and steam. Scope 2 emissions are naturally higher for companies that require significant amounts of i.e., electricity to run their operations

Scope 3: Captures all indirect value chain GHG emissions that are associated with a company's operations and not captured by scope 2. This includes both upstream and downstream in the value chain, with the composition of scope 3 GHG emission sources varying widely depending on the company in question, operations, products, services or suppliers.

Scope 1: captures GHG emissions from operations and assets that are owned or controlled by a company and is of notable importance in sectors with high direct emissions such as fossil-fuel based processing industry, electricity generation and manufacturing.

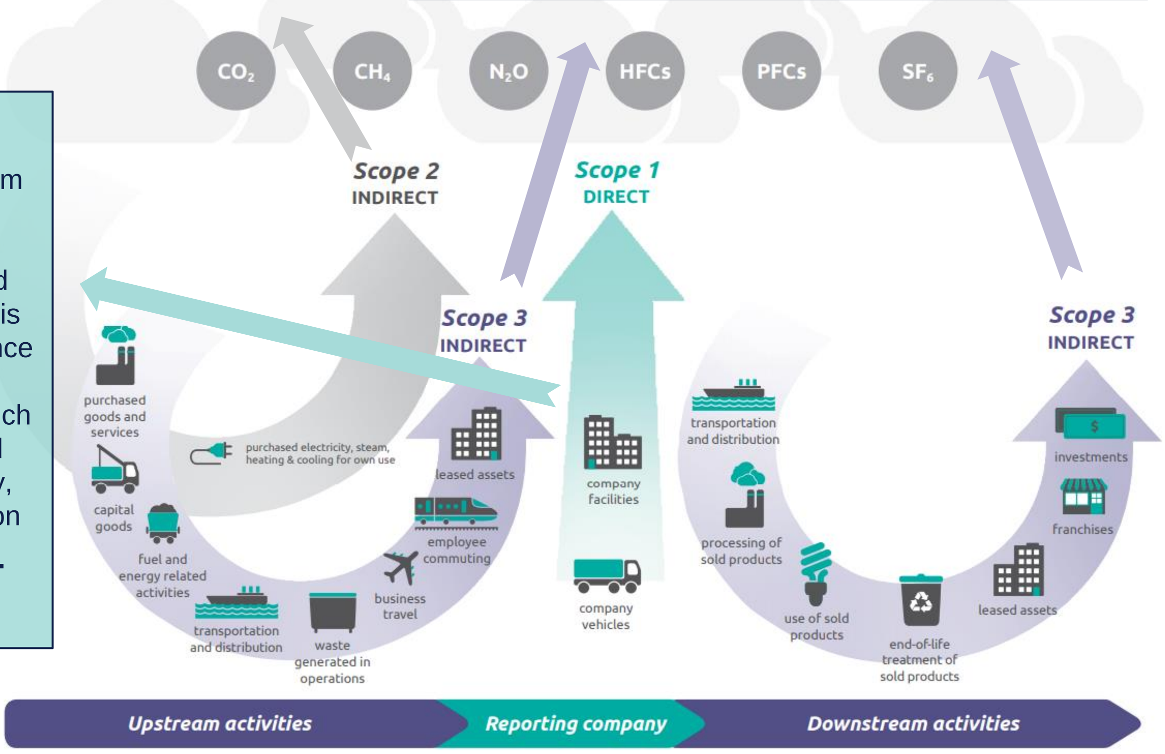

Figure: GHG Protocol

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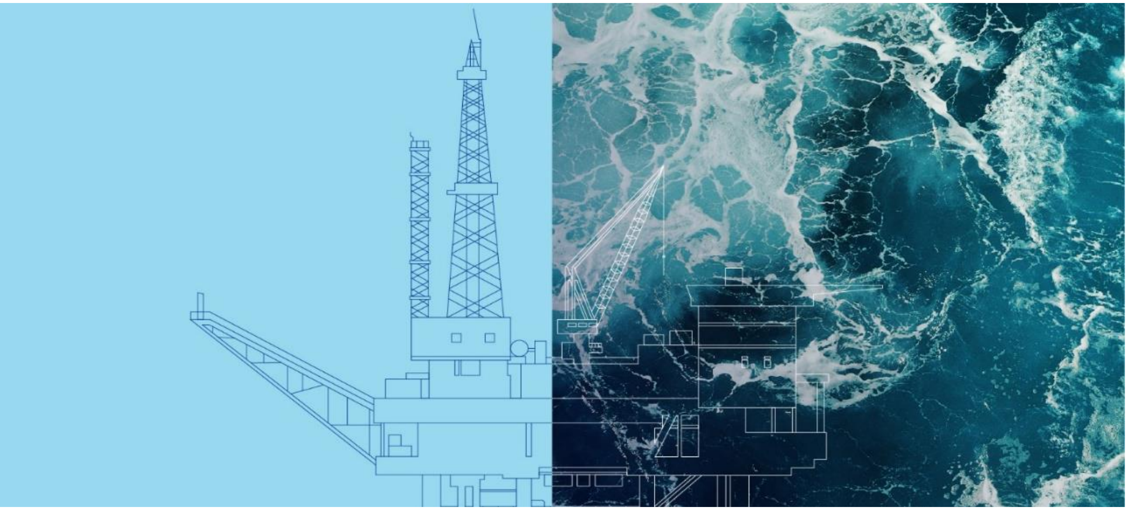
DNV

1.4 Introduction to scope 1, 2 and 3 emissions
What are scope 1 emissions?

Scope 1 – Addressing direct emissions

- Scope 1 emissions can be defined as “direct GHG emission that occur from source that are controlled or owned by an organisation” Within this definition, emissions from sources such as fuel combustion, furnaces, boilers, vehicles and so on are measured. For the oil and gas sector, a large share of the scope 1 emissions come from the operation of gas turbines offshore.
- As scope 1 emissions are directly under a corporate’s control, they can be directly positively or negatively influenced by corporate action. Scope 1 emissions are therefore naturally the main focus of carbon emission reduction compliance schemes. For example, carbon trading schemes such as the EU emissions trading scheme (ETS) imposes a carbon emissions allowance cap on scope 1 emissions for various high-emitting economic activities, which declines year-on-year to reflect annual EU GHG reduction targets.
- The overarching decarbonisation focus on scope 1 emissions reflects that any company’s scope 2 or 3 emissions is another company’s scope 1 emissions. Hence, to decarbonize value chains, all companies involved in the relevant value chain must reduce their own scope 1 emissions.
- Based on this logic, strict decarbonization requirements for electricity generators would reduce the scope 2 emissions for all companies buying electricity. Shipping decarbonization would reduce midstream scope 3 emissions for all companies shipping their materials with the relevant shipping company, while natural gas power with CCS would reduce downstream scope 3 emissions for a gas producer. In short, every company should start their decarbonisation action with focus on scope 1, but at the same time it is important to realise that decarbonisation of entire value chains are nessessary in order to meet the target of limiting climate warming to 1.5 degrees.



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1.4 Introduction to scope 1, 2 and 3 emissions
What are scope 2 emissions?

Scope 2 – documenting carbon intensity of electricity use

- Scope 2 emissions can be defined as "indirect GHG emissions associated with the purchase of electricity, steam, heat, or cooling". While the emissions are considered scope 1 for the electricity and/or heat generator, they are the result of the demand of the consumer requiring i.e., electricity for its operations. The emissions are thus indirectly a result of that company's activity.
- Documenting that scope 2 emissions reduce over time is integrally linked to i.e., power generators being able to document that their electricity has a falling carbon intensity. The GHG protocol outlines two main ways that consumers of electricity, heat, cooling and steam can document its carbon intensity, namely:
  1. Location-based reporting: which means reporting on the intensity of the electricity in the national or regional grid. This will thus reflect the intensity of the physical electricity within a defined area over a year.
  2. Market-based reporting: This method enable renewable energy generators to receive certificates that prove the renewable attributes of a unit of electricity. This certificate can thus be sold to an electricity consumer which can cancel such a certificate to prove that a unit of consumed electricity is green. As such, the attributes of the electricity is decoupled from the physical electricity on the grid. The European guarantees of origin scheme (GoO) is a market-based reporting scheme, while the map on the right highlight other relevant schemes.
- There is inconsistency in which of the approaches are used by companies, but the GHG protocol stipulates that both should be reported on.

Schemes for electricity attribute certificates globally

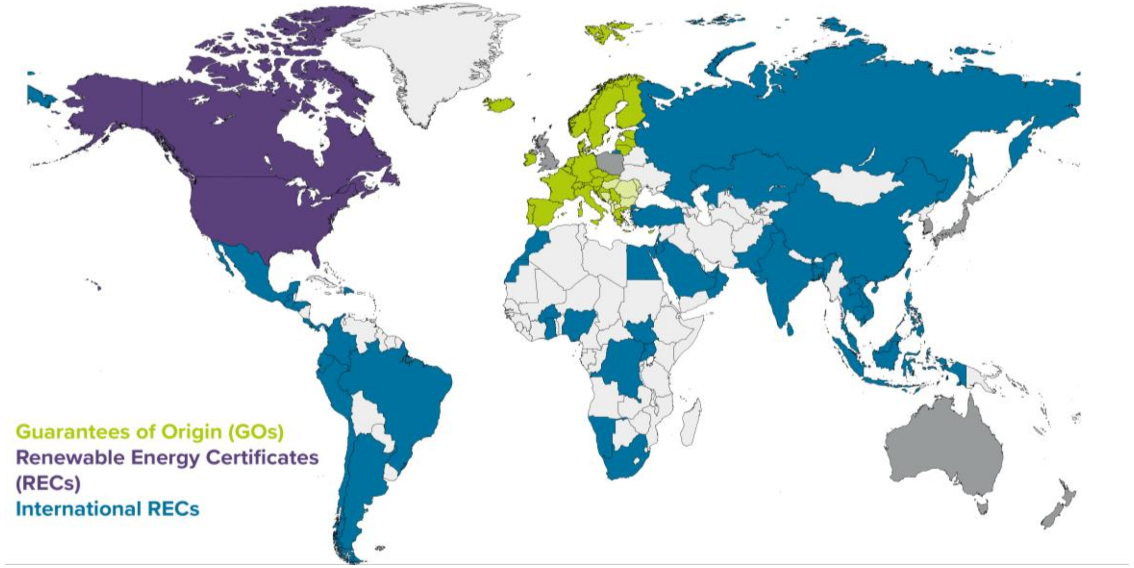

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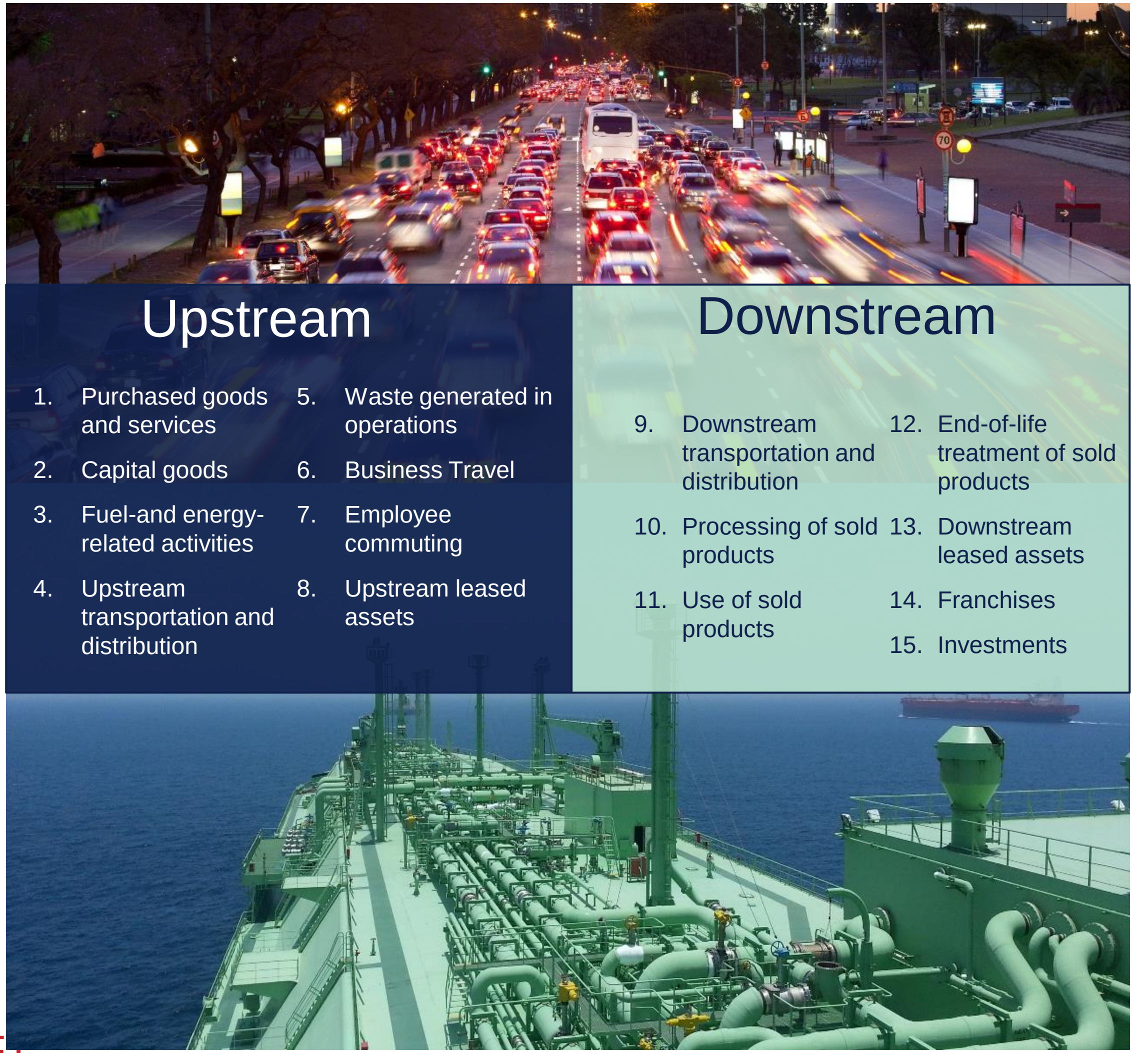
Figure: ECOHZ

1.4 Introduction to scope 1, 2 and 3 emissions

What are scope 3 emissions?

Scope 3 – the ‘iceberg’ emissions challenge for oil and gas

- **Indirect value chain emissions:** Scope 3 emissions can be defined as being the “result of activities from assets not owned or controlled by the reporting organization, but that the organization indirectly impacts in its value chain”. The GHG protocol outlines a total of 15 categories for scope 3 emissions.
- **Sector characteristics shape scope 3 profile:** For example, renewable energy projects with zero scope 1 emissions could source services, goods and materials from a more polluting upstream supply chain, leading to relatively high scope 3 emissions. Similarly, Oil and gas companies could have close to carbon-neutral scope 1 emissions from production activities, but will likely by default have high scope 3 downstream emissions from “use of sold products”.
- **Use of sold products:** For some oil and gas companies, scope 3 emissions can represent >85% of the total value chain emissions – notably in the form of category 11 “Use of sold products”. Category 11 is thus key in the eyes of investors – who considers this a notable transition risk in their portfolios.
- **Pressures on companies ramping up:** Oil and gas companies increasingly are expected to report on scope 3 emissions and include them in decarbonization targets, to capture full value chain emissions. Failure to do so may restrict access to competitive financing and negatively impact company value. Hence devising ways to reduce scope 3 emissions for Norwegian oil and gas companies will become a key facet of ensuring the future competitiveness of such companies and safeguarding the value of the industry.
- **Pressures for Norway:** a logical extension to pressures on companies is that countries over time will be expected to report on emissions outside of its own carbon budget boundaries, this could entail a form of category 11 reporting on the use of exported oil and gas and would dramatically increase Norway’s carbon emissions (by including value chain emissions).



Upstream

1. Purchased goods and services
2. Capital goods
3. Fuel-and energy-related activities
4. Upstream transportation and distribution
5. Waste generated in operations
6. Business Travel
7. Employee commuting
8. Upstream leased assets

Downstream

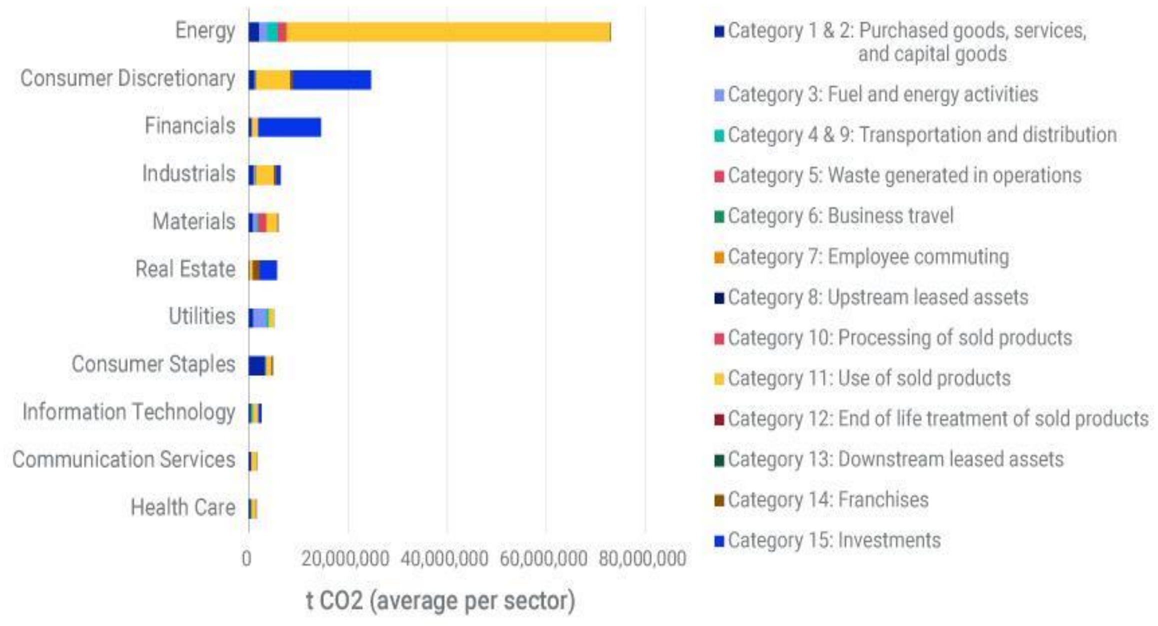
9. Downstream transportation and distribution
10. Processing of sold products
11. Use of sold products
12. End-of-life treatment of sold products
13. Downstream leased assets
14. Franchises
15. Investments

1.4 Introduction to scope 1, 2 and 3 emissions
GHG protocol categories – focus on category 11 and natural gas

Overview

- **Category 11:** For the oil and gas sector, around 75% of scope 3 emissions stem from downstream use of sold products (category 11) and 15% stems from upstream purchased goods and services. The remaining 10% is roughly equally divided into capital goods, upstream transportation and distribution, processing of sold products, and remaining relevant categories.
- **Category 11 emission reductions:** The most optimal value chain emission outcomes for oil and gas would target the decarbonization of product end-use. This would be achieved either by
    I. decarbonizing the feedstock prior to end-use, i.e., converting natural gas into blue hydrogen with CCS, or
    II. decarbonizing the feedstock at the point of end-use, i.e., natural gas power with CCS. Oil and gas companies typically have little control over downstream emissions but could in theory sign bilateral sales agreements that would entail carbon emission abatement by i.e., the gas end-user.
- **Natural gas vs oil:** A key focus of this study is natural gas, as down-stream use of sold oil decline through the switch to electric vehicles and low-carbon fuels in heavier transport (>50% of oil use).
- **Other categories:** While these are relatively smaller components of an oil and gas company's scope 3 emissions footprint, they nonetheless can comprise a substantial volume of GHG emissions. Decarbonization can be enabled by i.e., setting procurement requirements for
    I. service/goods suppliers and/or capital goods (**category 1 and 2**)
    II. transport & distribution upstream and downstream (**category 4 & 9**).

Estimated scope 3 emissions per category per sector



Source: MSCI

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2. Setting the scene

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2.1 Future demand for oil and gas

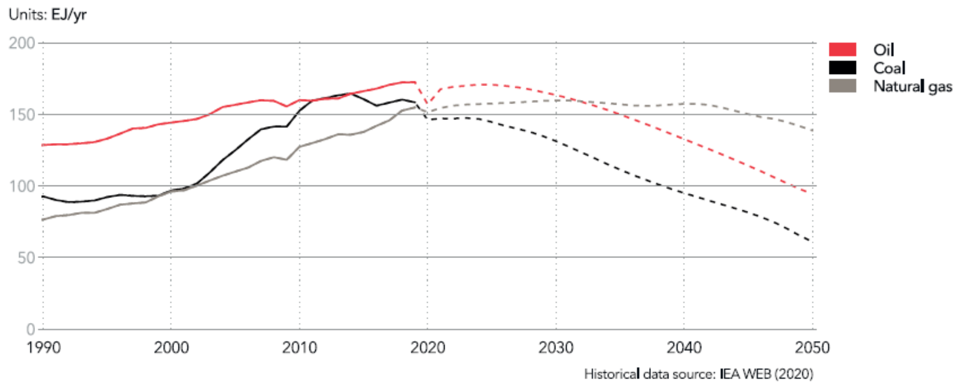
The demand for oil and gas in the energy transition is uncertain, but gas will likely surpass oil as the main fossil energy source

Global oil and gas demand

- Several scenarios for reaching the net-zero targets have been developed in the last decade, showing a wide span in projected oil and gas demand towards 2050. In our DNV Energy Transition Outlook (2021), we expect that global natural gas supply will surpass oil to become the largest primary energy source in the early 2030s, with relatively stable gas supply towards 2040 before declining towards 2050.

World primary fossil fuel supply by source

Source: DNV ETO (2021)

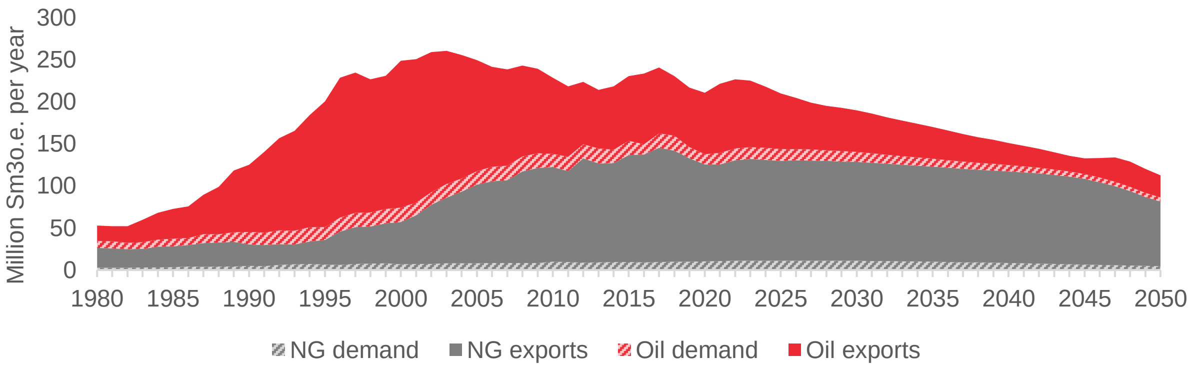


Production on the NCS

- Towards 2050, DNV expect oil production on the NCS to decrease as several oil fields are approaching end-of-life. Increased global competition in a shrinking market will see oil prices fall, and few new discoveries are expected to be developed [1]. Moreover, in “Tilleggsmelding til Meld. St. 36 (2020-2021)” from the Norwegian government, it was specified that all new development plans shall include a stress test against financial climate risk towards scenarios for the oil and gas prices that align with the 1.5-degree target [2], which could impact the appetite for new developments.
- In last years’ Energy Transition Norway (ETN), DNV expected natural gas production on the NCS to slightly increase in the coming decade, before declining by 2030. However, as more than 95% of Norway’s natural gas is exported to the European market, what happens in the European Union will have a large impact on the sales of natural gas from the NCS.

Oil and gas production on the NCS

Source: DNV ETN (2021)



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1) DNV Energy Transition Norway (2021)

2) https://www.regjeringen.no/no/aktuelt/pm-tilleggsmelding/id2908251/

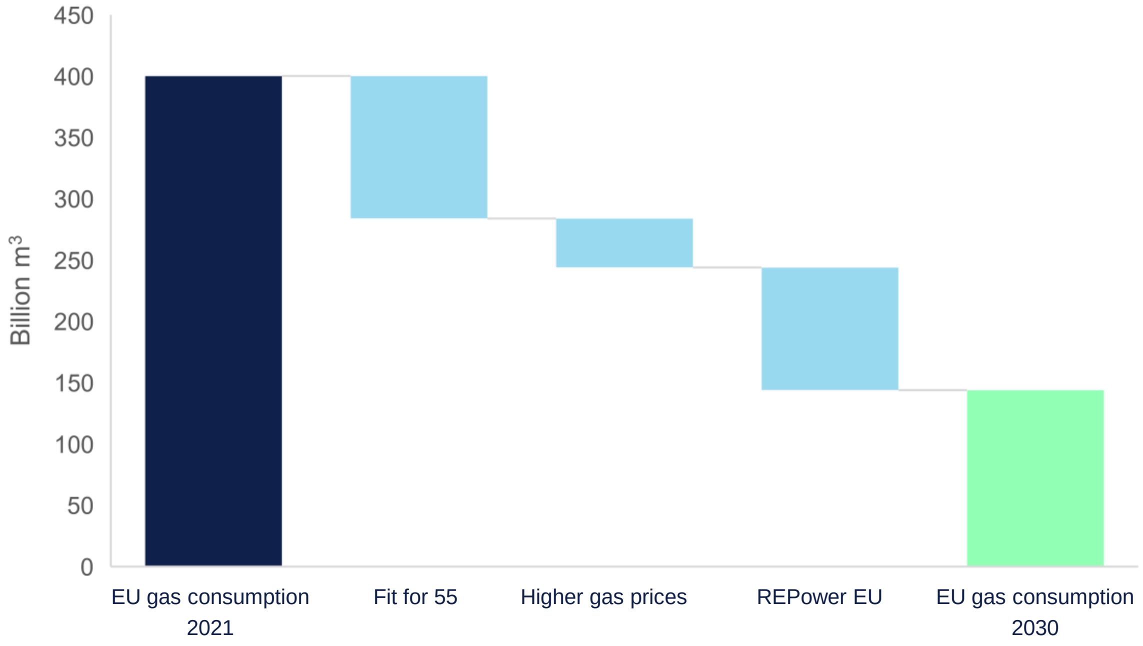
2.1 Future demand for oil and gas

European demand for natural gas will likely be significantly reduced

- The Ukrainian war has shed a new light on energy security. The EU has, through REPower EU, determined to rid itself of Russian gas through a combination of energy savings, increased renewables, and import of gas from diverse sources – such as Norway.
- According to new estimates from the European Commission, the EU would be able to replace all Russian gas (around 155 billion m3) by 2027. However, the estimates also show the beginning of phasing out non-Russian gas before 2030, based on proposed measures from the "Fit for 55" package and REPower EU, as well as higher-than-expected gas prices which will lead to increased nuclear and coal-fired power plants. Summing up, as seen in the figure, this means that almost two thirds of the EU's gas consumption can be replaced in 2030 [1].
- Although the REPower EU measures highlights scope for continued natural gas exports from Norway to Europe in the short-term, the accelerated phase-out of natural gas can pose a risk with Norway being the second-largest supplier of natural gas to Europe. However, it should be noted that LNG, which will cover a large percentage of the non-Russian gas imports to Europe towards 2030, both has higher energy losses and scope 1 emissions tied to it than piped natural gas from Norway.

How EU plans to reduce its natural gas demand towards 2030

Source: Energi og klima (22.05.22), based on released note from the European Commission



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1) Energi og klima, 25.05.22, https://energiogklima.no/nyhet/brussel/eu-notat-dramatisk-kutt-i-eus-gassbehov-etter-2030/

2.2 GHG emissions on the NCS

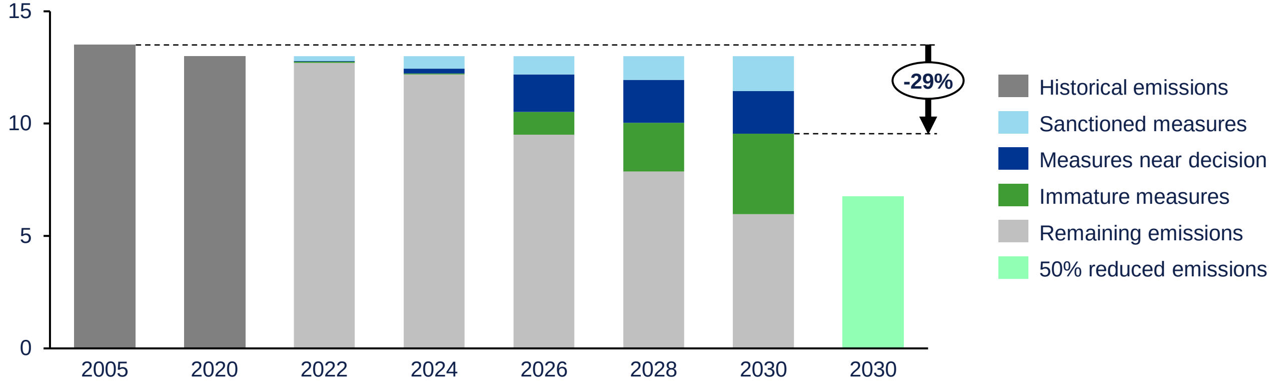
With current sanctioned and mature measures, emission levels are likely to be down by 29% in 2030

- The Norwegian Petroleum Directorate (NPD) estimates that the scope 1 emissions on the NCS and onshore facilities will likely be reduced by 15% towards 2030 through already sanctioned measures. When including measures near decision, including power from shore for Oseberg/Oseberg South as well as to Hammerfest LNG and gas terminals at Kårstø, the emission reductions could be closer to 29% [1].
  - The Konkraft status report from 2021 showed a reduction potential of around 12% from sanctioned and mature measures [2]. Although not comparable on an apple-to-apple basis, Konkraft has stated that the updated opportunity space of their new status report for 2022 is more in line with the NPD forecasts.
- Even if all sanctioned measures and measures nearing decision are operational before 2030, we still have a long way to go before reaching the target of 50% scope 1 emission reductions. More is yet to be done.
- It is also worth noting that of the 50+ registered fields, eight of them represented over 50% of the total scope 1 emissions in 2020, as shown in the figure to the right. Without significant emission reductions on these fields, the targets are almost impossible to achieve.
  - Note: This figure does not include onshore facilities, and only shows the fields representing in total 90% of all scope 1 emissions on the NCS.
- *Note: DNV is working to gather and project GHG emission data on the NCS and onshore facilities, including sanctioned or planned measures, for the second phase of the project. However, the data sources are not consistent, partly due to proprietary information and the decisions regarding new decarbonization projects are not easily available.*

Historical and forecasted emissions on the NCS and onshore facilities

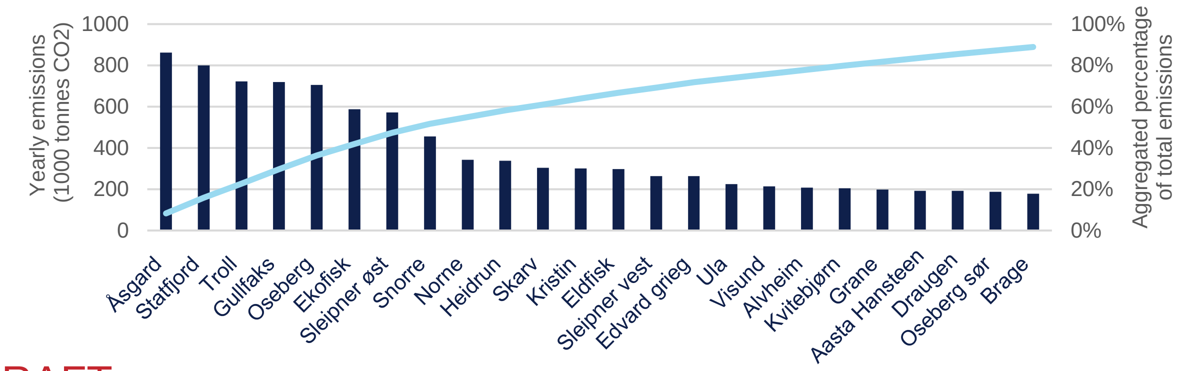
[million tonnes CO_2eq per year]

Source: NPD (2021)



Annual and aggregated CO_2 emissions for fields on the NCS (2020)

Source: Miljødirektoratet (2020)



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1) https://www.regjeringen.no/no/dokumenter/meld.-st.-36-20202021/id2860081/?ch=5#kap5-3
2) Konkraft (2021)

2.2 GHG emissions on the NCS

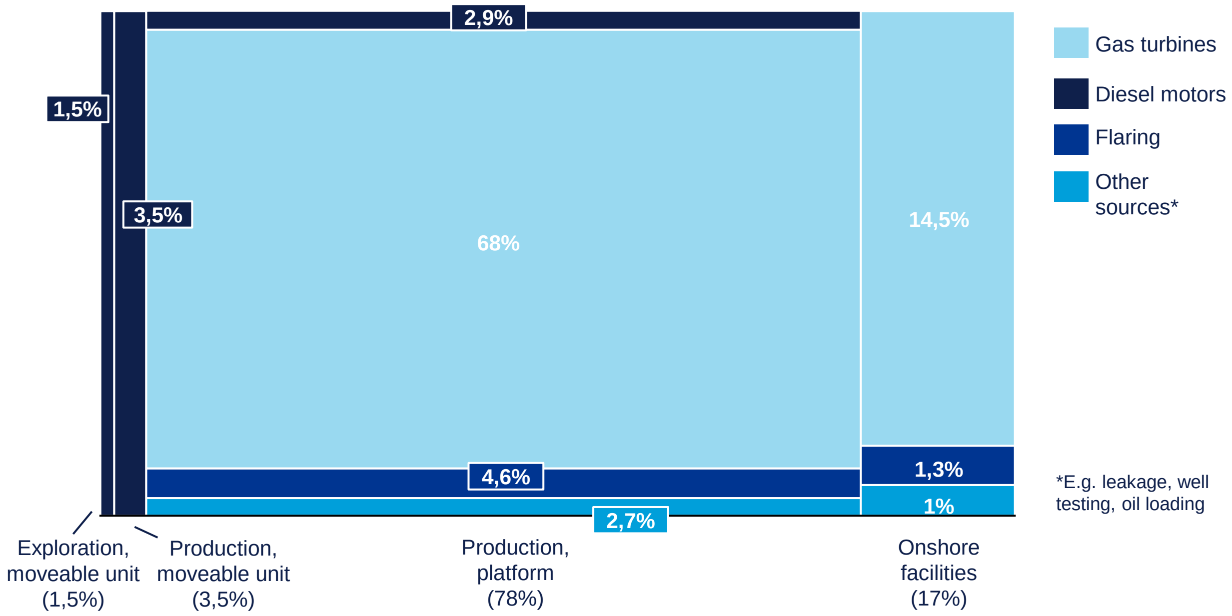
Turbines account for around 83% of total scope 1 emissions on the NCS

- The chart to the right outlines the total scope 1 emissions from the NCS (including onshore activities) in 2019, categorised into activities and emission sources.
- **Activity:** In 2019, around 78% of total scope 1 emissions occurred from platforms on producing fields, while 17% occurred during onshore activities.
- **Emission sources:** Fuel combustion in gas turbines is by far the largest source of emissions, with 83% of total scope 1 emissions coming from these turbines in 2019 (68% from platforms and 15% from onshore facilities).

Scope 1 emissions from the NCS in 2019, by emission source and activity

[% of total Mt CO_2-eq emitted]

Source: SSB, figure inspired by Rystad (2019)



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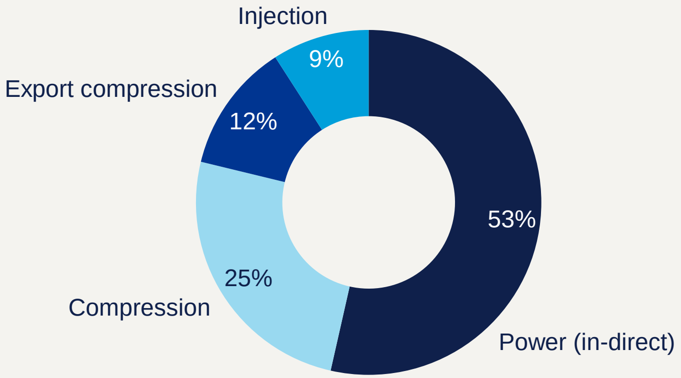
2.2 GHG emissions on the NCS

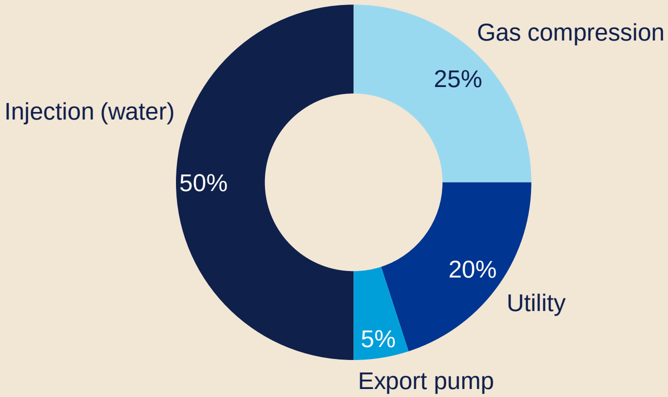
The turbine related emissions vary between gas and oil fields

GAS FIELDS



- More than 50% of the normal turbine load is related to power generation to be used for utility, compression or injection.
- These power generator turbines can be more easily replaced with electric power, known as part-electrification. Replacing the turbines driving compressors and pumps requires more extensive modifications on existing platforms, and is more expensive.
- Processing gas also requires some heat, which can be generated from waste heat from the gas turbines. A full electrification would require installing electrical heaters [1].

OIL FIELDS



- On typical oil fields, water injection is the most energy intensive operations.
- Gas compression for transport is the second largest energy intensive operation, and together with water injection this accounts for around 75% of gas turbine emissions from oil fields [1]. If measures can be taken to reduce energy demand from these operations or replace the turbines, this could lead to large emission reductions.
- The emissions from gas turbines vary depending on the energy efficiency and load (e.g. the strategy of having back-up turbines running on low load leads to reduced efficiency and increased emissions)

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1) Rystad (2019)

2.2 GHG emissions on the NCS
Several technologies can be used to replace gas turbines

- As seen in the previous slides, the main measure for reducing scope 1 emissions on the NCS and from onshore facilities is by reducing emissions from gas turbines. This can be done through several measures, such as:
  - Electrification measures, either from shore, from power hubs offshore, or directly from offshore wind
  - Measures involving CCS, such as centralized power hubs or decentralized top-side
  - Gas turbines running on alternative, low-carbon fuels
- Another way of reducing the emissions from gas turbines is by reducing the energy demand or optimise how gas turbines are run, i.e., avoid part-load and aim for the load rate giving the highest possible thermal efficiency.
- Electrification from shore is seen as the main opportunity for reducing emissions towards 2030, but recent developments have sparked the debate on whether the NCS should be electrified from shore.

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2.3 Electrification
The debate on NCS electrification

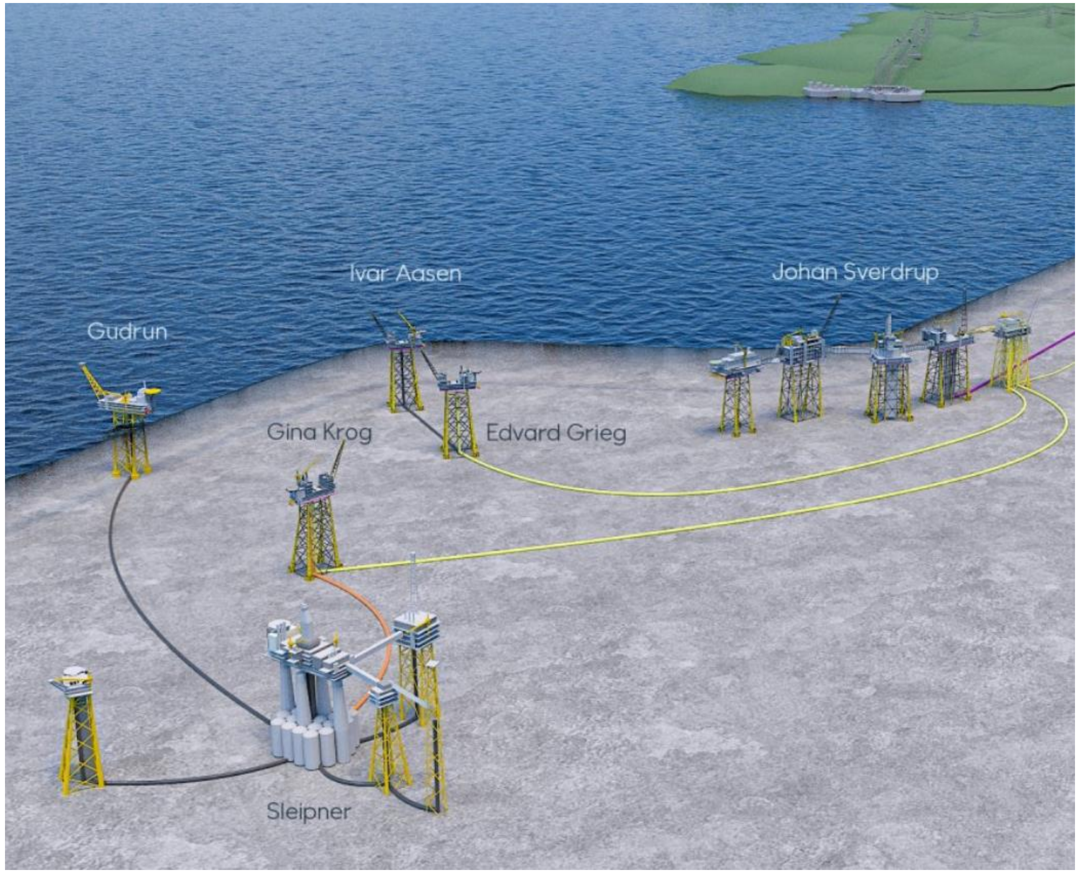

Figure: Electrification of Utsirahøyden (Equinor)

- Electrification of the NCS has long been considered as crucial and a self evident measure that needs to be taken in order to reach Norway’s 2030 climate goals.
- With increasing electricity prices, extensive electrification plans, the war in Ukraine and little new electricity production in the pipeline a new debate on how the available electricity is best employed has emerged:
  - Where will the available electricity give the most value from a societal perspective?
    - This is a complex and important question and one of the primary reasons electricity trade is organised in contestable markets. If the market organisation ensures prices are competitive, without subsidies, user discrimination or other distortions, and environmental concerns are properly implemented in regulation, the market participants' willingness to pay for electricity will ensure only the most valuable uses, from a societal perspective, are prioritised.
  - What long term outlook do the projects that use the limited electric resources have?
    - Lifetime of electrification projects matter

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2.3 Electrification

European and Norwegian power market overview

- The European and Norwegian electricity markets are in constant development
  - Stricter 2030 climate goals and higher CO2 prices
  - Increasing interconnectivity between European countries and increased reliance on wind and solar imply different price volatility in Norway as well as abroad – less impact of dry vs. wet years, and of night vs. day, different impact of seasonality, and increased impact of high vs. low wind
  - Uncertain and volatile gas and CO2-prices due to the war in Ukraine and other political developments
  - A lot of new offshore wind and hydrogen production expected in Europe as technology prices are coming down
  - All in all, this gives higher and more volatile power prices across Europe
- In Norway, electrification trends are expected to dominate in the next 5-10 years, but new production capacity is not keeping up
  - DNV's ETO Norway, Statnett and NVE all predict that the Norwegian power surplus will be significantly reduced or diminished some time between 2025 and 2030.
    - New generation capacity is temporarily coming to a halt and will be limited to what is already under construction. After 2030 it will pick up again with more offshore and onshore wind projects being realised. There is also some potential for solar PV
    - Four sectors are expected to drive the increase in demand: Industry, transport, oil and gas production and hydrogen production. How much is electrified will vary with prices and increased production capacity
  - Looking ahead, today's price level in Southern Norway will likely subside with higher reservoir levels. Somewhat lower prices than in Europe are expected.
  - However, higher and more volatile price levels are expected over the coming years. Domestic price differences are also likely to continue.

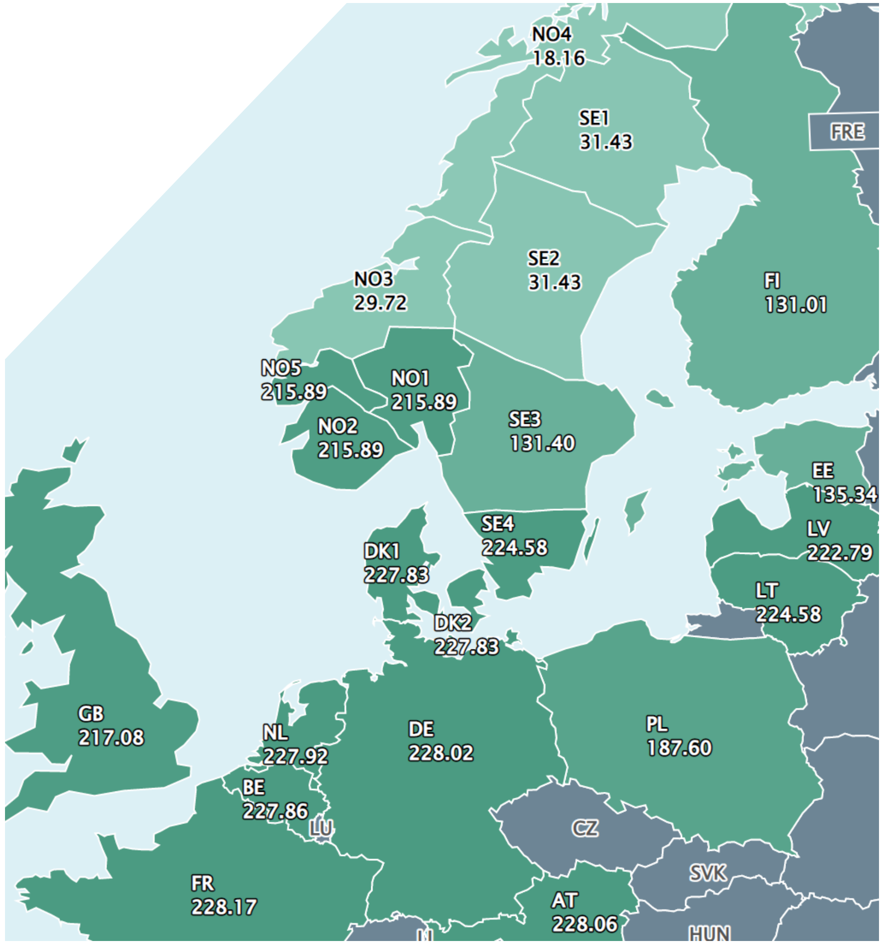

Figure: Hourly power price (19-20, NOK) in Europe, 28th April 2022 (Nordpool)

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2.3 Electrification
Norwegian Power market predictions

Statnett, Long-term market analysis

Statnett has recently published a long-term market analysis (2020-2050) with a December 2021 update, and a short term market analysis (2021-2026). The reports predict little new power production before the end of this decade beyond what is currently being built.

On the demand side, the requests Statnett has received for connections point to increasing certainty about new demand connecting to the grid. All in all, this gives a development where a power surplus of 15 TWh in 2021 is reduced to 3 TWh in 2026 before it increases again after 2030. Electricity demand in the petroleum sector is expected to grow from 9,5 TWh in 2020 to 20 TWh in 2030.

Average power prices are expected to follow a “high scenario” development as of December 2021. An increase is expected especially towards 2025 before they fall somewhat to 2030. The price increases are expected to be lower in Northern and mid-Norway and that European influence will give more power trade and volatility.

NVE, Long-term market analysis

NVE’s long term market analysis (2021-2040) point to how access to sufficient grid capacity, production and power prices will have a considerable influence on how much the demand for new electricity increases. They particularly highlight the transport, petroleum and industrial sectors, whilst hydrogen production also can make a significant impact if realised.

On the production side, NVE includes Solar PV to a larger extent in their predictions than Statnett, but have similar views on both onshore and offshore wind being realised from 2030 onwards. In their basis scenario they predict a reduction in the Norwegian power surplus from 20 to 7 TWh towards 2030.

Similar to Statnett, the power demand in the petroleum sector is expected to be roughly 20 TWh. They also point to how electrification of the petroleum sector is resulting in significant grid investments around the country.

They also put emphasis on how Norwegian power prices are strongly affected by renewable expansion and technology developments in continental Europe and the access to surplus power production in the Nordics.

DNV, Energy Transition Outlook (2021)

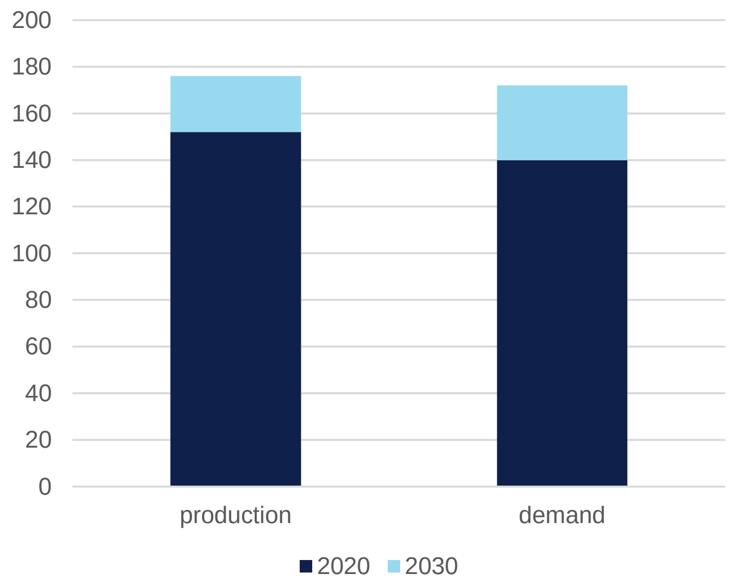
DNV’s Energy Transition Outlook towards 2050 forecasts that households, service industries, as well as the electrification of transport, will consume the existing Norwegian electricity surplus. This will lead to a deficit of domestic electricity supply for further decarbonization plans as well as new industrial growth within sectors such as battery factories, green steel, alumina and electrolysis-based hydrogen production.

On the production side, new hydropower capacity is limited and onshore wind is facing increased public resistance. Offshore wind is then the technology that can increase power production the most going forward, although the lead time for these projects are long.

To supply the Norwegian Continental Shelf (NCS) with electricity while simultaneously supporting green industrial growth, Norway must likely import electricity for several years between 2025-2035. Increased reliance and exposure to European power prices can cause volatility as well as potentially higher prices – reducing the competitive advantage of low-priced green electricity needed for industrial production. The ETO therefore forecasts severe challenges in juggling ambitions of electricity surplus, reducing emissions as well as supporting industrial growth before significant volumes of offshore wind is connected to the grid towards 2035.

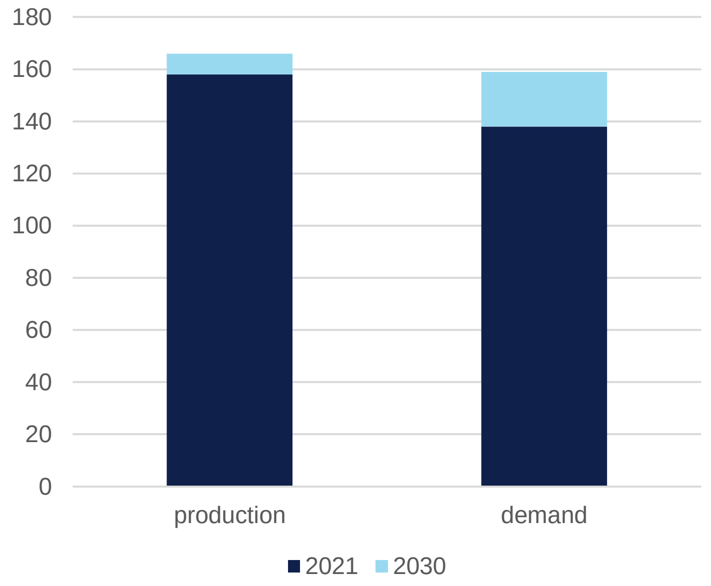
DNV

Electrification
Statnett and NVE forecasts



The Statnett forecast gives a 2020 surplus of 15 TWh and 4 TWh in 2030. Demand increases from 140 TWh in 2020 to 172 TWh in 2030, whilst production only increases from 152 TWh in 2020 to 176 TWh in 2030.

Based on Statnett's 2020-2050 Long term Analysis, with small update in dec 2021



The NVE forecast gives a statistical 2021 surplus of 20 TWh and 7 TWh in 2030. Production will grow from 158 TWh in 2021 to 166 TWh in 2030, and consumption will grow from 138 TWh in 2021 to 159 TWh in 2030

Based on NVE's 2021-2040 Long term Analysis

Comments

- Both forecasts give surplus numbers in 2030 that can easily be diminished if hydropower production is lower than expected or demand increases more than expected.
- Note that NVE's numbers are based on 2021, considerable wind power was connected to the grid over the last year
- Other differences in production is mainly related to when new offshore wind is connected to the grid
- NVE has slightly lower estimates of new electricity demand, this is mostly related to onshore industry expansion

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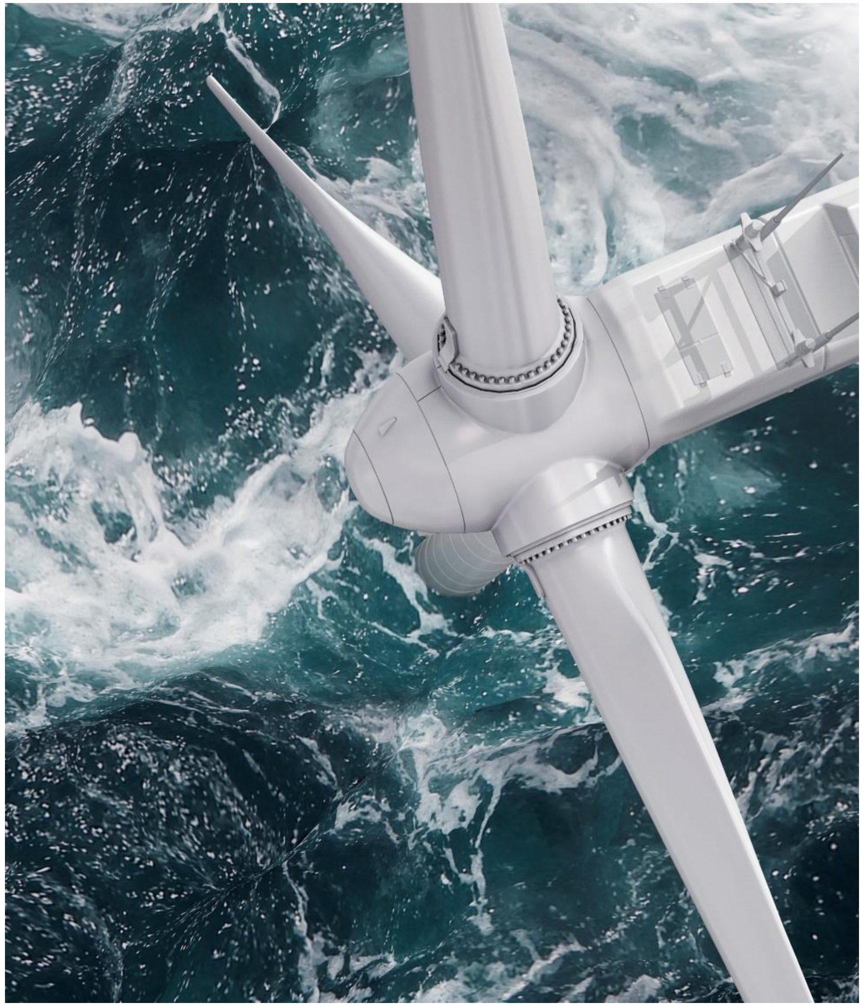
Electrification

What elements will influence the electrification of the NCS?



1. Statnett is the Norwegian Transmission System Operator (TSO) responsible for operation and development of the Norwegian Transmission grid. They have an **obligation to connect customers to the grid if they ask for it**.
   - However, the customer has to pay for any necessary grid expansions
   - Any new major grid investment project also need to receive a licence from the government in order to be realised
2. A lot of **new electricity demand is expected** in the coming years. In some sectors demand is growing rapidly already with great momentum.
   - This especially applies to the transport sector which is an important sector to decarbonise, with considerable political support
3. For other sectors, **grid reinforcements, new production capacity and power prices** will have a considerable influence on how much the demand for new electricity increases.
   - This applies to all sectors with growing electricity demand, including the petroleum sector
4. The degree to which battery factories, other (power intensive) industry and hydrogen production develop projects in Norway will **influence the debate on how extensively the NCS can be electrified**.
   - More new industry = more competition for scarce resources = higher prices and potential public and political resistance
5. For NCS-electrification projects, it could be relevant **where the O&G platforms connect to the grid**
   - North/south price differences
6. If NCS-electrification projects can show that they have concrete plans to connect to or **cooperate with new renewable/decarbonisation industries** such as offshore wind, hydrogen production, CCS etc, this will extend the lifetime of the O&G platforms, giving less climate risk and extending the lifetime of the platforms.
   - Electrifying platforms that will only be profitable for a finite period of time can give lower total value than onshore projects
7. **Higher CO_2-prices** gives economic incentives for more electrification, but can also make alternative solutions more viable

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DNV

3. Reaching the GHG emission reduction targets

DRAFT

3.1 Introduction to assessment approach

From long-list to short-list of opportunities for reducing scope 1 emissions

Long-list of decarbonization opportunities

Based on input from OG21, DNV has identified a long list of opportunities for reducing scope 1 emissions on the NCS and for onshore facilities.

The opportunities are described on a high level based on a set of screening criteria (see next page).

Half-day workshop with OG21 TG's

The long list of opportunities where discussed in five separate half-day workshops with each Technology Group (TG) in OG21.

The focus of the workshops was to discuss the preliminary assessment by DNV of each opportunity, with emphasis on main development and implementation obstacles as well as possible solutions. The input from the workshops fed into the assessments by DNV.

Short-listing opportunities for Phase 2

Based on the initial assessment by DNV as well as input from the half-day workshops with TG's, the opportunities where compared based on the initial screening criteria using a "high, medium, low" scoring methodology.

Based on the comparison and scoring, a set of short-listed opportunities move into the second phase of the project for a more thorough assessment.

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3.1 Introduction to assessment approach
Screening criteria

GHG reduction potential	The scope 1 emission reduction potential is assessed on a high level based on: • **The targeted emission sources** (e.g. gas turbines) and related emissions • **The technical reduction potential**, i.e. the amount of emissions that can theoretically be reduced by replacing the targeted emission sources with the chosen opportunity • **The application and scaling potential**, i.e. the realistic percentage of targeted emission sources that could be replaced by the chosen opportunity, given the assessed scaling potential.
Maturity	The **maturity** is assessed based on the Technical Readiness Level (TRL) of an opportunity, in the short term (2022-2030) and long term (2030-2050). DNV has used the API-scale on TRL's (TRL 1-7).
Application scope and scaling potential	• The **application scope** looks at for what applications the chosen opportunity is relevant on the NCS and onshore facilities. • The **scaling potential** assesses the timeline for when we expect sufficient scaling and maturity of the chosen opportunity.
Development and implementation obstacles	Here we list the **main development and implementation obstacles**, including but not limited to cost levels, footprint (weight and volume), major risks or safety concerns, infrastructure challenges, and political and societal trends.
Industry opportunities and synergies	In this screening criteria, we assess the industry opportunities for Norway for the chosen opportunity as well as possible synergies.

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3.1 Introduction to assessment approach
Long-list of decarbonization opportunities

- Based on initial input from OG21 as well as internal discussions, the following long-list of opportunities for reducing scope 1 emissions are assessed in Phase 1 of the study:
  - Electrification
    - Includes electrification from shore and from offshore power hubs, both using a coordinated and individual approach, as well as local supply from offshore wind
  - Offshore gas-fired power plants with CCS
    - Based on input from TG workshops, onshore gas-fired power plants with CCS are also assessed
  - Compact topside CCS
  - Hydrogen and hydrogen-derived fuels for power production
  - Energy efficiency through reservoir management
    - Includes water management, CO_2-EOR and artificial intelligence
  - Optimized gas turbines
    - Includes gas turbines for waste heat recovery as well as technologies for optimizing utilization
  - Geothermal energy

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3.2 Decarbonization opportunities
Overview of (some) electrification options

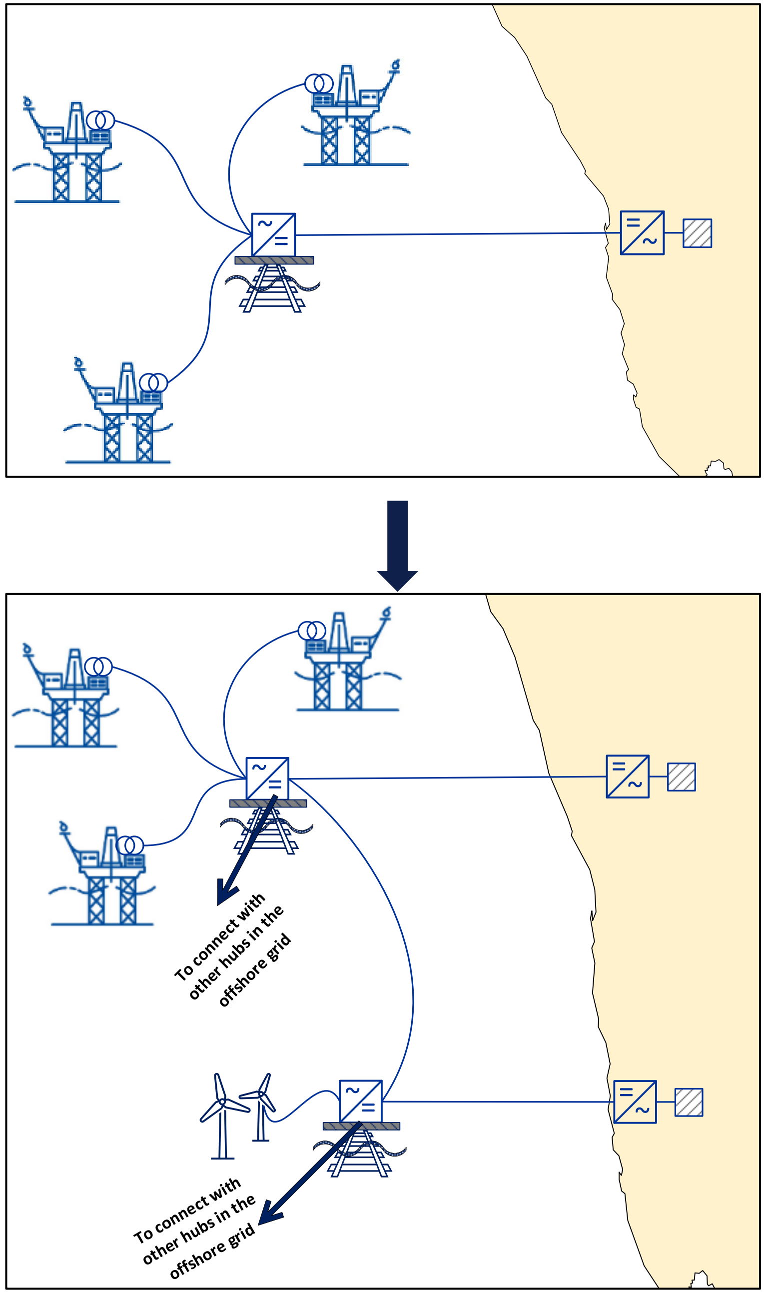
Picture: Equnior

- The are multiple opportunities for electrification of offshore energy consumption. These can be combined in numerous ways.
- There are some fundamentally different network design options to supply the relevant offshore electricity consumption:
  1. **Coordinated**: Numerous fields supplied via (some) offshore energy hubs
     - Hubs are connected to shore(s) and/or offshore wind farms etc.
  2. **Individual**: Each field supplied via direct connection to shore
  3. **Local supply**: Each field supplied from local (offshore), dedicated electricity generation source (wind and/or some thermal alternative)
- On the next pages, we will explain some generic economic and regulatory features of these designs, including why 1 and 2 essentially represent mutually exclusive alternatives while 3 can be combined with both.
  - In reality, final choices are likely to be a combination of 1 for some fields and 2 for others, plus 3 for some of both designs

3.2 Decarbonization opportunities

Electrification: Coordinated approach

- Multiple fields supplied via offshore hub(s)
- Johan Sverdrup (phase 2) is a good example of this type of solution
  - A large connection to the onshore network, combined with smaller connections to the individual platforms
    - Could alternatively be connected to other offshore hubs, energy islands, large offshore wind farms, etc.
    - Connections to shore will typically be DC, while the local offshore connectors will be AC or DC depending on distance and power
- To electrify 'everything' along the coast, one would need connections to shore and/or to other energy hubs
  - The resulting network design will have some similarities with the meshed onshore network
  - Eventually, the network design can evolve into a truly meshed network over time, and integrate with the meshed offshore grid in the North Sea for offshore wind integration.
- This type of solution requires significant coordination of stakeholders (primarily licensees/operators) and represent complex decisions and decision making procedures
- The key benefits are significant economies of scale, both in terms of investments and in terms of regulatory processes, potential for higher security of supply at lower costs, and potential for fewer conflicting interests



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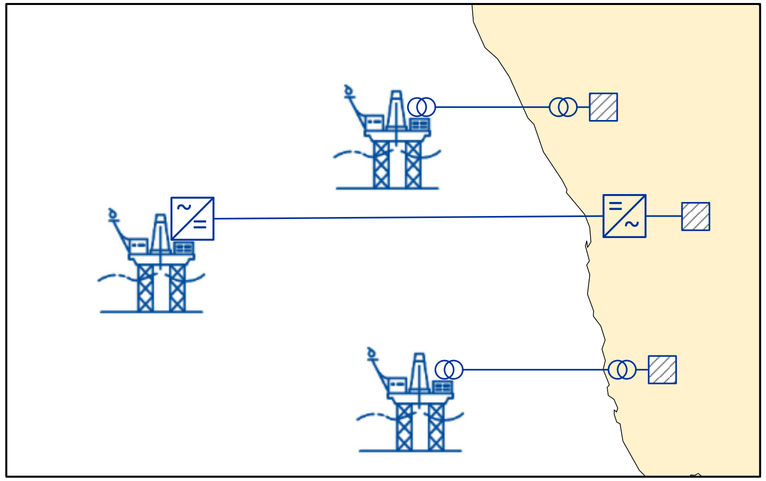
3.2 Decarbonization opportunities
Electrification: Individual approach

- Unique onshore connection for each field
- Most of the existing power from shore projects (Goliat, Gjøa, Martin Linge) are examples of this approach
  - Individual connections tailored to each field/platform.
- To electrify 'everything' along the coast, one would need a large number of such radial connections to shore
  - The resulting network design will simply be a large number of radial connections, in some regions connected to the same point onshore
  - Choice between AC and DC depends largely on distance and power
- This approach does not require the same amount of coordinated decision making, and is likely if there is no (or insufficient) coordination. Individual decisions are complex, but less than for the coordinated approach
- The key benefit is the lower complexity in decision making
- The disadvantages are significantly higher (investments) costs, higher costs to ensure N-1* supply, more regulatory processes related to connections to shore, and larger scope for conflicting interests (environmental, use of areas, local on-shore network issues)

* N-1 implies that the system service (delivery to customer) will not be impacted with the loss of any individual component.



AC or DC?

- **Historically the HVAC technology was used when the distance to shore is lower than 200 km:**
  - \+ Mature technology
  - \+ Lower footprint on platform
  - \+ Higher losses
  - \- Power rating limited by cable rating (< 200 MW per project)
  - \- Normally require complicated reactive compensation onshore (SVC or STATCOM plus shunt reactors)
  - \- Need Frequency Converter to supply 60 Hz platforms
- **HVDC was used with distance longer than 200 km:**
  - \+ Lower loss
  - \+ Distance and power rating not limited
  - \+ Providing support to onshore AC grids
  - \+ Supplying 50 Hz or 60 Hz platform equally well
  - \- Technology still under development
  - \- Large footprint on platform (HVDC converter)

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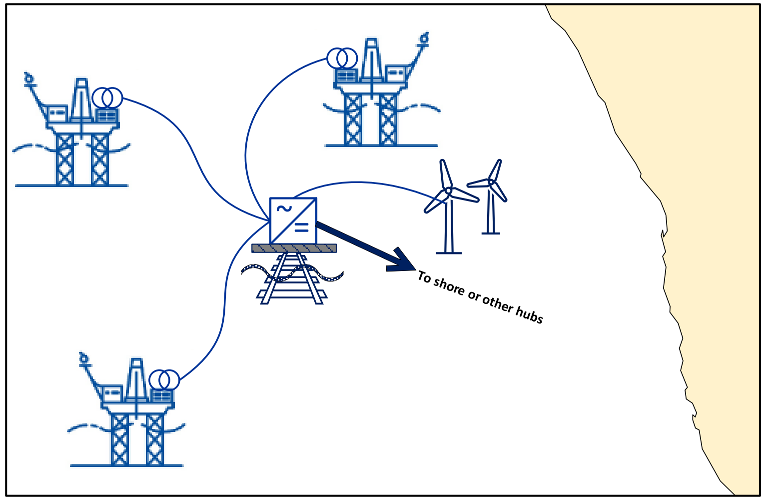
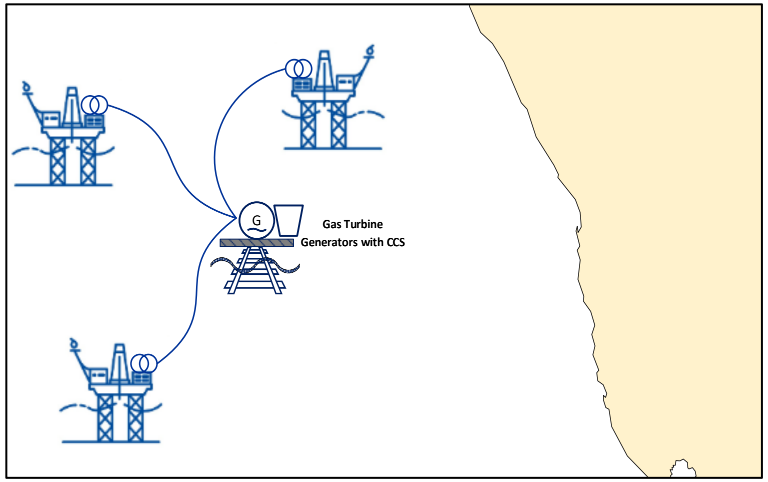
3.2 Decarbonization opportunities
Electrification: Local supply

- Dedicated local supply to each field (wind and/or thermal alternatives)
- Both the coordinated design and the individual solutions can be combined with a supply of locally generated electricity. A local solution does not require a connection to shore or other hubs at all, and is thus also an independent alternative
- The complexity and the decision making process depend on each case
- In combination with a coordinated or individual connection to shore, it can ensure N-1 supply
- Potentially attractive if there is significant distance to shore or other hubs





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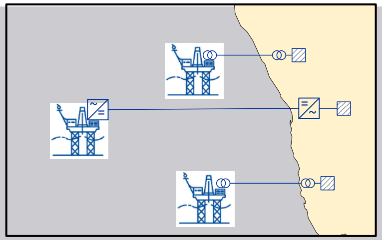
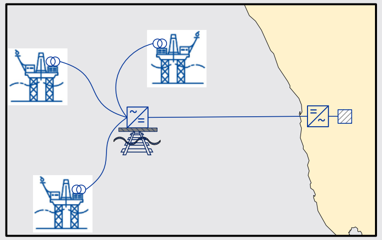
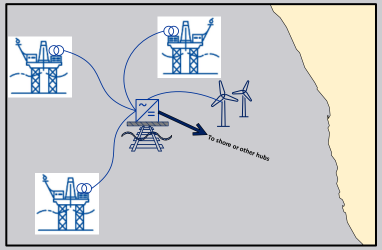
3.2 Decarbonization opportunities

Electrification: Summary of coordinated, individual and local supply

Connection concept	Description	Illustrative figure
Individual	Each platform is connected to the onshore grid via a dedicated radial connection, which can be either HVAC (for distances to onshore POI up to 180 km) or HVDC for distances over 200 km. Note this design relies on (i) the capacity of the interconnector cable from the platform to shore (maximum capacity to e.g. 400 MW HVAC or 1,200 MW HVDC), and (ii) the hosting capacity of the point of interconnection on the onshore grid. This design offers a simplicity in design and the smallest total amount of cable laid offshore and provides the advantages of resource diversity, redundancy and associated reliability benefits.	
Coordinated	In this design, multiple platforms are connected to one offshore hub (shared substation) before being further connected to onshore grid. Note this design relies on (i) smaller OSW farms that can aggregate to a common export cable to shore (maximum capacity of that common cable limited to e.g. 400 MW HVAC or 1,200 MW HVDC) and (ii) relies on a point of interconnection on the onshore grid that can handle significant injections of energy at a shared substation. This design balances a minimized cable landfall footprint with the potential risks of limited redundancy and associated impacts to reliability.	
Local supply	Both the coordinated design and the individual solutions can be combined with a supply of locally generated electricity. A local solution does not require a connection to shore or other hubs at all, and is thus also an independent alternative. The local supply can be from various sources, such as offshore wind or from a power hub concept with CCS.	

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3.2 Decarbonization opportunities
Electrification: Coordinated and individual supply

Various options for electrification are promising solutions with the highest GHG reduction potential, high technology maturity level and abundant synergy with the booming offshore wind industry.

Short description

Individual: Each platform is connected to the onshore grid via a dedicated radial connection, which can be either HVAC (for distances to onshore POI up to 180 km) or HVDC for distances over 200 km. Note this design relies on (i) the capacity of the interconnector cable from the platform to shore (maximum capacity to e.g. 400 MW HVAC or 1,200 MW HVDC), and (ii) the hosting capacity of the point of interconnection on the onshore grid.

This design offers a simplicity in design and the smallest total amount of cable laid offshore and provides the advantages of resource diversity, redundancy and associated reliability benefits.

Coordinated: Multiple platforms are connected to one offshore hub (shared substation) before being further connected to onshore grid. Note this design relies on (i) smaller OSW farms that can aggregate to a common export cable to shore (maximum capacity of that common cable limited to e.g. 400 MW HVAC or 1,200 MW HVDC) and (ii) relies on a point of interconnection on the onshore grid that can handle significant injections of energy at a shared substation.

This design balances a minimized cable landfall footprint with the potential risks of limited redundancy and associated impacts to reliability.

Application scope and scaling potential

Application scope

- Electricity (from shore, offshore wind or power hub) can replace 100% of the electricity generated by gas turbine generators.
- Some platforms use the recovered waste heat from gas turbine to provide the necessary heating for offshore process, this part should be covered by additional electrical boiler or heat pump if the gas turbine generators are to be replaced.
- Gas turbines are used in some projects to directly drive the large motors or pumps through mechanic coupling, replacing those gas turbines is possible but expensive and complicated.

Scaling potential and timeline

Short term (2022-2030): Both individual and coordinated electrification have been implemented in NCS, the power ratings can be as high as 200 MW and capable of power several platforms in the vicinities, the distance to shore can be up to 160 km (AC) and 200-300 km (HVDC)

Long term (2030-2050): When connecting with the meshed offshore grid in North Sea with abundant offshore wind, the power rating per individual link can reach 1200 MW or 2000 MW, the reachable range of such solution can potentially cover the whole NCS.

Maturity
Technology Readiness Level (TRL)

Short term (2022 – 2030):
TRL 7 for individual solution, also TRL 6/7 for coordinated built-out when supplied from onshore grid

Long term (2030 – 2050):
Large scale meshed offshore grid in North Sea will reach TRL 7.

Accelerating developments

1. Supply chain risk (limited qualified suppliers for HVDC converters and submarine power cables)
2. Sector-coupling synergy with offshore wind
3. Dynamic cables and turret / High Voltage Slip ring for the connection of floating platforms;
4. Multivendor Inter-operability of HVDC systems

3.2 Decarbonization opportunities
Electrification: Coordinated and individual supply

GHG reduction potential

Target emission sources
Electrification can replace gas-fired turbines, both for power production (part electrification) as well as turbines for compression and injection (full electrification). Gas-fired turbines account for around 83% of total scope 1 emissions.

Technical reduction potential
Electrification can theoretically reduce scope 1 emission from gas turbines by 100%, although resulting in a small increase in scope 2 emissions.

Realistic reduction potential
With turbines accounting for 83% of total emissions and power production from the turbines contributing to around 50% of total energy use, a partial electrification could potentially reduce scope 1 emissions by 45%. A full electrification would further reduce emissions. The realistic potential is, however, largely dependent on each case, considering available space for converters, distance from shore, downtime needed for retrofitting, and more.

Main challenges and opportunities

Development and implementation obstacles
- Weight and space limitation for DC equipment
- Weight and space limitation for electrical heaters (if replacing heat demand)
- Hz-regime (50 or 60Hz) and the need for transformers
- Distance from shore (AC versus DC and costs implied)
- Electrifying direct-driven turbines (full electrification) more challenging and costly than partial electrification, increasing complexity of reducing remaining emissions through electrification.
- Full electrification concept requires electrical heaters to cover heat demand.
- Dynamic cables for voltages over 66 kV AC for connecting floating assets may need to be specially qualified. DC dynamic cables not mature technology.
- Downtime on brownfields during retrofitting, and loss of revenue.
- Availability of electricity onshore and political debate

Individual vs coordinated:
- Individual: Requires large number of radial connections to shore, resulting in a sub-optimal network design. Significantly higher (investment) costs, higher costs to ensure N-1 supply, more regulatory processes related to connections to shore, larger scope for conflicting interests (environmental, use of areas, local on-shore network issues). Key benefit is lower complexity in decision making.
- Coordinated: Requires significant coordination of stakeholders and represent complex decision-making procedures. Key benefits are significant economics of scale (investment and regulatory processes), potential for higher security of supply at lower costs, potential for fewer conflicting interests.

Industry opportunities and synergies
The coordinated approach has the alternative to be connected to offshore power hubs, energy islands and/or large offshore wind farms, providing significant industrial opportunities for Norway and synergies with offshore wind developments in the North Sea as well as emerging industries such as hydrogen production (in combination with offshore wind, providing flexibility and storage). Moreover, the resulting network design could gradually build into a meshed offshore grid and connect to the planned North Sea offshore grid in the long-term.

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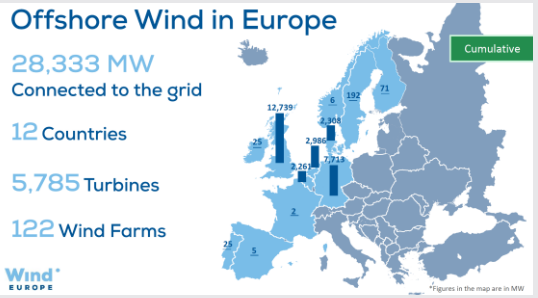
3.2 Decarbonization opportunities
Electrification: Local supply from offshore wind

Offshore wind is at an applicable level of maturity and can be used to reduce the use of gas-fired turbines on the NCS.

Short description

Bottom fixed wind is fully commercial with over 28 GW by 2021 installed in Europe [1], but still more expensive then other energy sources. Floating wind is approaching large scale and commerciality, with only a few years before we will see the large multi unit-projects (>20 units). Innovation and developments are still needed to cut cost to make the solution competitive.

Offshore wind is a more secure source of wind energy than onshore, however, there will be variation of production due to shifting wind speed. Power from wind energy must therefor be implemented in combination with storage and/or other power sources.



Application scope and scaling potential

Application scope
- Offshore wind can replace or reduce the use of gas turbines for electrical purposes.

- Offshore wind can be a replacement of the gas turbines for water injection.

Scaling potential and timeline
Short term (2022-2030):
Within 2030 the scaling will mainly be limited by the lack of floating substations for very large deep water sites. Bottom-fixed offshore wind is fully scalable as of today.

Long term (2030-2050):
In the long term both bottom fixed and floating wind will be fully cost competitive solutions. The scalability will mainly be limited by distance from shore and conflict of interest for the most feasible nearshore areas.

Maturity
Technology Readiness Level (TRL)

Short term (2022 – 2030):
Bottom-fixed wind is a fully proven and commercial applicable with a TRL level of 7.

For floating wind the spar and semisubmersible floating concepts are currently at a TRL 6, and will within the short term of 2030 be at the highest TRL level. Other floater concepts such as barge and TLP has a lower TRL of 5 and 3 respectively, but is also expected to be at a high TRL level within short term.

New application area requires learning and developments of the full system integration. In WIN WIN the complete water injection by offshore wind system was given a TRL 4 [2].

Long term (2030 – 2050):
Floating wind is expected to be commercialized within the long term perspective of 2030-2050 with the highest TRL level, and will during this period increase the CRI to 5/6.

Accelerating developments
Technical developments of dynamic cables and power integration with the platforms or a park.

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1) Wind Europe, Offshore wind energy 2021 statistics, March 2022
2) DNV, WIN WIN Joint Industry Project: Wind-Powered water injection, May 2019

3.2 Decarbonization opportunities
Electrification: Local supply from offshore wind

GHG reduction potential

Target emission sources
Offshore wind solutions can reduce the use of, or be a part of a replacement of the gas-fired turbines for power production at the NCS. The Norwegian Petroleum organization reports that 83% of the CO_2 emissions connected to the petroleum industry in Norway is due to turbines [1].

As presented in slide 18, 53% of the power from gas turbines are used for electrical purposes, and 9% for water injection. Electrifying these units (part electrification) is easier and less costly than a full electrification.

Technical reduction potential
With a sufficient storage solution it is technically possible to reduce the emissions from the gas turbines by 100% with offshore wind, however, offshore wind alone cannot replace the gas turbine due to the variable power supply.

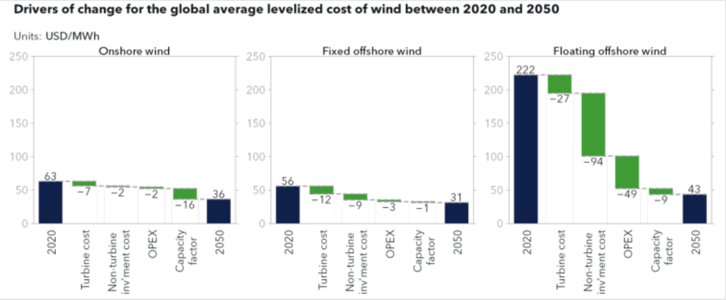
Realistic reduction potential
The realistic reduction of GHG depends on the site and the capacity of offshore wind and the infrastructure on the platform. Equinor reports that with Hywind Tampen with a capacity of 88 MW is estimated to reduce 35% of the annual electricity power demand of the five Snorre A and B, and Gullfaks A, B and C platforms, and offsetting 200,000 tonnes of CO2 emissions and 1,000 tonnes of NOx emissions per year [2].

Main challenges and opportunities

Development and implementation obstacles
The biggest issue with regards to offshore wind is the variable/intermittent power delivery. Offshore wind is namely dependent on the inconsistent source of wind. To secure a steady energy source it is dependent on either storage solutions or another power supply.

The offshore wind floater technology is ready, however, some technological gaps on dynamic cables, power integration, and floating offshore substations are yet to close. In Norway, the 30 GW target on offshore wind installations by 2040 shows commitment to industry, although it is still not clear how the target will be reached and what regulations and requirements will come.

One of the other main challenges is the cost. The solutions are there, however, the cost of especially floating wind is not yet competitive in the power market. DNV predicts that the LCOE of offshore wind will be 31 USD/MWh for bottom fixed and 43 USD/MWh for floating in 2050, and right below 60 USD/MWh for floating and 41 USD/MWh for bottom fixed in 2030 [3]. These reduction is expected to be driven through investment and large-scale projects.



Industry opportunities and synergies
Europe has a bold offshore wind target of 60GW by 2030 and 300 GW by 2050 [4], and Norway has recently set targets of 30GW offshore wind by 2040. Development and upskilling of the Norwegian industry and supply chain will be highly valuable in the European market, but the knowledge is fully transferable worldwide.

At the end of the lifetime of the platform the offshore wind can be scaled up and/or connected either to the Norwegian inland, or connect to the a export cable selling and supporting Europe with their energy need. The offshore wind units can also be used for production of alternative fuels such as hydrogen or as an offshore charging station. For floating wind there is also a focus on movable units, making the production flexible and directly able to sell or reuse the floater at another location.

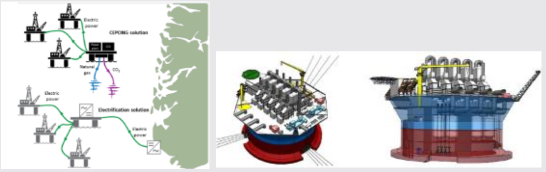
1) Norsk petroleum, https://www.norskpetroleum.no/miljo-og-teknologi/utslipp-til-luft/, August 2021
2) Equinor, https://www.equinor.com/energy/hywind-tampen, August 2019
3) DNV, Energy Transition Outlook, 2021
4) offshoreWIND.biz, https://www.offshorewind.biz/2022/02/16/eu-streamlining-path-to-300-gw-by-2050-offshore-wind-target/, February 2022

3.2 Decarbonization opportunities
Gas power hubs offshore with CCS, serving the NCS

Gas turbines on platforms in addition to land-based gas turbines are the largest upstream and midstream CO_2 emitters (scope 1). One technical solution for reducing these emissions is through electrification via a central gas power hub offshore with CCS. Compared to a onshore power plant with CCS serving the NCS, such a solution could provide a potential for a cost efficient solution as it e.g., provides an opportunity to re-use of existing infrastructure, avoid transport of natural gas and CO_2 over long distances etc.

Short description

- The offshore power plant could be based on a combined cycle configuration, including multiple gas turbines and steam turbines, utilising the gas turbine exhaust waste heat in Heat Recovery Steam Generators [1].
- The CO_2 capture technology could be based on the most mature capture technology involving amine based solvents, or other more novel capture technology.
- The location of the power hub should be based on a optimised CCS value chain, both in terms of cost and technical feasibility. This implies taking into account both cost and technical feasibility of the CO_2 transport and – storage.
- The location also need to depend on the potential for CO_2 reduction, i.e., number and/or size of the installation that can be electrified from the power hub.



Clean Electricity Production from Offshore Natural Gas (CEPONG) concept, [1]

Application scope and scaling potential

Application scope
A power hub offshore should be assessed in relation to electrification from shore in terms of application. Hence, replacing gas turbines offshore directly by providing sufficient power through electricity.

Scaling potential and timeline
Short term (2022-2030):
- Development of a offshore power hub would require a timeline beyond 2030. Hence, the potential of CO_2 reduction from this measure could not be expected on a short term.

Long term (2030-2050):
- On a longer term the offshore power hub could have a huge potential, but location of such hubs and the following CO_2 reduction potential is difficult to assess. In a study by SINTEF [1] the concept of offshore power hubs with CCS is assessed to have a CO_2 reduction potential of 90% (based on capture ration for mature solvents).

Maturity
Technology Readiness Level (TRL)

Short term (2022 – 2030):
- Capture technology TRL 5 (applied onshore, but not offshore)
- CO_2 transport: Flexible pipelines TRL 5
- CO_2 transport by ship: offshore loading/offloading systems TRL 2-3

Long term (2030 – 2050):
- Capture technology TRL 7 (dependent on technology development)

Accelerating developments
Develop accessible CO_2 storage infrastructure – including CO_2 shipping if transport will be based on shipping.
Explore models to connect with existing CO_2 storage projects such as Northern Lights (NO) and/or others.

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[1] Roussanaly, S., et al, 2018, *Offshore power generation with carbon capture and storage to decarbonise mainland electricity and offshore oil and gas installations: A techno-economic analysis,* CEPONG project (Climit)

3.2 Decarbonization opportunities
Gas power hubs offshore with CCS, serving the NCS

GHG reduction potential
Target emission sources Replacing gas turbines on O&G platforms. In 2019, gas turbines offshore made up 68% of total upstream and midstream CO_2 emissions.
Technical reduction potential Based on current technology one could assume a capture rate between 80-90% from the gas turbine exhaust gas (dependent on optimal configuration offshore), hence also representing the CO_2 reduction potential from turbine emissions at a offshore gas power hub. One would also gain a higher electrical efficiency in such a hub-system compared to single turbines on platform that often is operated on part-load. To realise this potential a fully developed value chain for transport and storage of the CO_2 is required. CCS is commercially proven and there are a number of successfully CCS project such as Sleipner and Snøhvit (Norway) and Quest (Canada). CCS can be scaled depending on the volume of CO_2 to be stored. CO_2 can be stored in either saline aquifers or depleted fields
Realistic reduction potential The potential for CCS related to NCS is constrained by finding suitable subsurface storage complexes within economic transport distances of the offshore gas power hubs. Large scale CO_2 storage derisking is required to identify exact storage sites. However, Norway has already conducted the first phase of regional storage screening of the NCS. The Norwegian CO_2 storage Atlas has already high graded locations on the NCS and associated capacity estimates for the key areas. Detailed appraisal activities will further derisk these high graded areas. A combination of saline aquifers and depleted fields need to be screened, assessed and ranked versus transport distance from the offshore gas power hubs. According to the CO_2 storage Atlas sufficient CO_2 storage capacity exist on NCS to decarbonise gas power hubs offshore

Main challenges and opportunities
Development and implementation obstacles Key considerations for gas power hub with CCS: • Finding a suitable storage site: The storage complex needs to prove containment, sufficient capacity, economic rate of injection and monitorability. • Optimised location for power hub: Need to take into account optimised cost and technical feasibility of CO_2 transport and storage in addition to electrification potential of installations (e.g. distance for electricity transport and installations possibility to be electrified) • Competitiveness of offshore gas power with CCS vs. other power hub concepts (wind, electrification from shore) • Spatial planning: The power hub could compete with other activities as wind farms, oil & gas activities etc. • Cost for CO_2 capture technology and application of the technology in offshore conditions • CO_2 spec and required polishing for transport and injection purposes (material integrity) • If ship transport: Offshore loading/offloading technology • Opportunities to benefit from the CCS value chain developed for other CCS projects (common storage site for other sources) • Opportunities for reuse of existing infrastructure
Industry opportunities and synergies • Additional CO_2 source for Northern Lights phase 2 (5 MTPA) [2] • Open up more storage locations for potential cross border CO2 storage • Further cements Norway leading edge as a Global Leader in CCS activities • Develop the Norwegian CCS supply chain

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[1] Miljødirektoratet; Klimagassutslipp fra olje- og gassutvinning (miljodirektoratet.no)

[2] https://ccsnorway.com/app/uploads/sites/6/2020/07/Plan-for-long-term-use-of-the-Northern-Lights-infrastructure-1.pdf

3.2 Decarbonization opportunities
Compact topside CCS

Gas turbines on platforms in addition to land-based gas turbines are the largest upstream and midstream CO_2 emitters (scope 1). One technical solution for reducing these emissions is through CO_2 capture and storage directly at the installation. Being limited due to weight and volume constraints on the platform capture technology will need lighter and smaller units than the ones used onshore. However, developments are progressing and the first commercial products for offshore applications are recently made available on the market. Availability of feasible CO_2 storage is the major bottleneck.

Short description

- A carbon capture system removes the CO_2 from the flue gas of the gas turbines and produce a concentrated CO_2 stream that can be sent to geological storage.
- CO_2 capture systems can be design to remove up to 95% of the CO_2 produced by the gas turbine. There are no operating capture systems on gas turbines to date, although this is technically feasible.
- New and existing offshore installations might allow limited weight and volume additions when it comes to including or retrofitting CO_2 capture systems. Floating platforms need special designs to account of motion effects.
- Tailored CO_2 capture systems optimized for offshore applications are being developed, including systems designed for floating applications (i.e. FPSO).
- Aker Carbon Capture has recently presented versions of their technology specifically tailored for FPSO applications [1]. This system is based on well-known solvent-based capture processes.
- There are technologies under development that could provide a higher level of compactness and better capture efficiencies. Relevant examples are the systems developed by Compact Carbon Capture and Net-Power but they are currently developed for onshore applications.

Application scope and scaling potential

Application scope

- It would be platform specific, not all brown field platforms can be retrofitted for capture or have access to CO2 storage at feasible distance.
- CO_2 storage might be constrained by location of suitable site nearby the platform.
- Volume of CO_2 captured is about 4 kt/y for each MWe installed (a 30 MW GT corresponds to about 120 kt/y captured).
- Scope for this option will depend on a full cost benefit analysis of the whole capture, transport and storage value chain

Scaling potential and timeline

Capture technologies are technically mature and commercially available – they can be retrofitted on existing installation if there are no space and load limitations. Bottleneck is the access to qualified CO_2 storage sites, it takes at least 5 years to develop a CO_2 storage site (depleted field), it can be longer for an aquifer – all depends on data availability. Before 2030 it is likely that only a few projects could succeed. Afterwards, a more developed CCS infrastructure and lower cost could results in greater pick up. Potential in long term after 2040 could be limited by the increasing public pressure on closing down fossil fuel operations and a decreased need in oil&gas as a result of the energy transition.

Maturity
Technology Readiness Level (TRL)

Short term (2022 – 2030):
Capture systems for offshore applications not subjected to motion have a TRL of 5/6, depending on technology provider – the technology is available and proven but there are no operating commercial version yet in offshore environment. Systems for floating platforms or FPSO, that are subjected to motion have not been implemented, meaning a slightly lower TRL of 4 even though some vendors already offer them on the market.

Long term (2030 – 2050):
TRL of 7 is expected for solvent based capture processes, for fixed or floating applications. New technologies will likely reach TRL 5/6 in this timeframe and are likely to become commercial.

Accelerating developments

- Develop accessible CO_2 storage infrastructure (Clusters / Hubs style development) – including CO2 shipping if transport will be based on shipping.
- Explore models to connect with existing CO_2 storage projects such as Northern Lights (NO) and/or others.

[1] Just Catch™ Offshore – Aker Carbon Capture

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3.2 Decarbonization opportunities
Compact topside CCS

GHG reduction potential

Target emission sources
O&G platforms, including floating ones and FPSOs, where power is supplied by a gas turbine installed on site. In 2020, gas turbines offshore made up 68% of total upstream and midstream CO_2 emissions.

Technical reduction potential
Solvent-based CO_2 capture processes are typically designed for removal of 90% of the CO_2 contained in the flue gas as this is the considered the soft spot to optimize capture rate vs costs. However, the capture rate is a design parameters and can be changed as desired. Higher capture rates like 95% is feasible although it requires more efficient (bigger) equipment and therefore comes at higher cost. A capture rate of 99% is theoretically feasible but requires an equipment size that is probably too big in dimensions for offshore applications and too costly.

Realistic reduction potential
The realistic reduction potential for a CO_2 capture system based on solvents is 90-95% of the gas turbine emissions. The potential for NCS is dependent on the limitations on brownfield assets when it comes to space and weight and the need for rebuild. Also, as stated for the gas power hub with CCS solution, availability of suitable storage site will impact significantly to the actual potential for this technology.

Main challenges and opportunities

Development and implementation obstacles
- Capture – not all brownfield platforms can be retro-fitted for CO_2 capture, due to space and weight constraints in existing O&G platforms.
- There needs to be a suitable CO_2 storage near by the platform, if none are available, transport via ship or pipeline to a suitable storage need to be developed.
- Technical challenges CO_2 Storage: each individual store needs to prove containment, sufficient capacity, economic rate of injection and monitorability. In addition, the storage activity could compete with other activities such as wind farms, oil & gas activities etc.
- Cost vs volume of CO_2 per installation: this option is likely more expensive than having centralised gas power hubs with CCS, mainly due to the economies of scale associated with a larger CO_2 stream to store vs a low volume stream per individual platform. Requires full cost benefit analysis

Industry opportunities and synergies
- The range of gas turbines models and sizes employed in offshore applications is rather restricted (i.e. M2500+G4, SGT750, LM6000), allowing easier modularization of CO_2 capture systems for offshore applications. This has benefit for costs reductions as well as for engineering and implementation.
- Gas turbines used in offshore applications are typically open cycle – this means that it many cases it is possible to recover waste heat from the GT exhaust to produce steam to run the CO_2 capture process (if solvent based). Although this means a higher CAPEX upfront, it has a significant advantage on the operating costs as one of the major requirements of the CO_2 capture system is related to the energy supply (e.g. steam supply).
- Platforms located in the same area, with relative small distance between them, could possibly use a common storage site and a transport infrastructure. This could have significant benefit for the cost and time required to implementing CCS.

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3.2 Decarbonization opportunities

CO_2 storage: Differing risk profiles of saline aquifers vs. depleted fields

Risk factor	Deep saline aquifers	Depleted fields
Containment **- Well** **- Faults & seal**	• Typically fewer legacy wells – primary anthropengic leakage path	• Typically higher density of legacy wells, as the field has been explored developed and produced
	• Faults and seals not geomechanically weakened through production - but depending on the distance from O&G fields are untested	• Due to depletion of HC, fields are geomechanically compromised • Proven in the local area to hold HC
Capacity	• Regional capacity ranges typically higher • Larger uncertainty range on capacity estimates prior to appraisal actives, linked to limited data on reservoirs (store) properties	• Typically offer smaller overall capacity, as the capacity is limited to the field size • Uncertainty on capacity range less, due to better reservoir (Store) knowledge – fields are data rich environments compared to saline saline aquifers
Injectivity	• Greater uncertainty due to lack of data, cannot be derisked until appraisal well conduct injectivity / production test(s)	• Production data gives you confidence on dynamic injectivity rates early on in CCS storage maturation phase • Depending on the amount of depletion, you may not be able to inject initially in a supercritical phase until the store is pressured to within the pressure envelope of supercritcal phase injection. • Alternately add additional heating and compression at the well head to protect the near well bore environment - injected CO_2 will still move freely, expand and cool rapidly (J-T cooling). These thermal effects can impact frac pressure of the store without careful management.
Monitorability	• Geophysical monitoring techniques inside of outside the store and the storage complex are not hampered by the presence of residual HC	• If residual HC remain, especially gas, they can inhibited geophysical (seismic) techniques aimed at visualizing plume migration with the confines of the structurally defined ''store' (injection reservoir) unit. However, it does not preclude the use of seismic outside for detecting CO_2 leakage or migration outside the defined store or storage
Other (HSSE and Appraisal costs)	• HSSE case simpler - no simultaneous operations occur if an aquifer is developed from a greenfield platform – only fluid on the platform is CO_2 • Potentially higher derisking costs – likely to require additional appraisal activities (wells, seismic, geo technical studies etc..) prior to FID	• Likely more complex HSSE case, if a brownfield platform is reused, a dual safety case is required for both CO_2 and HC being present on the platform • Depending on the number of legacy wells and state of abandonment – higher abandonment cost could occur prior to 1st injection – but limited appraisal cost as fields are data rich and unlikely to need to prove economic rates of injection due to wealth of HC production data.

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Decarbonization opportunities
Hydrogen and hydrogen-derived fuels for power production

One technical solution for reducing emissions from the gas turbines is by replacing natural gas with hydrogen or ammonia. Combustion of low calorific gaseous fuels in gas turbines is not unusual in the refining and steel making industries (e.g. blast furnace gas) however has not been applied offshore. Firing hydrogen in gas turbines for fully commercial reasons, depends on the attractiveness of the various power markets or power needs (island-operation). Note that hydrogen can also be used in combination with other technologies such as offshore wind to provide flexibility and storage. Hydrogen can also be used for power production from fuel cells, although this is not assessed here.

Short description

- Gas turbines are used land-based and on platforms.
- Gas turbines are a reliable technology for power generation and mechanical (compression) or marine drives.
- They are available in sizes from micro scale (tens to kilowatts) to very large scale (hundreds of megawatts). The newest medium to large sized simple cycle turbine models range between 5 and 600 MW. The most common one in NCS is 25 MW (LM2500)
- Traditionally these gas turbines fire natural gas as a primary fuel. Companies like General Electric, Kawasaki and Mitsubishi Power have gas turbines in their portfolio that are designed for low calorific process waste gases (steel industry, refineries).
- The main identifiers for gas turbines are their operating window, ramp rates, power output, heat rate, minimum load and (NOx) emissions. This is particularly true for gas turbines that have a dual fuel combustion system or allow for various process fuel gases from industrial sources.
- When firing hydrogen or ammonia, the consequences for gas turbine design are depending on type, operating profile, combustion system (premix/non-premix) and co-firing ratio.

Application scope and scaling potential

Application scope
Hydrogen firing in new gas turbines or in refurbished gas turbines. Various options;
- Co-firing of H2 with none or limited modifications (e.g 30% vol)
- Co-firing of H2 with burner modifications or replacement (tbd)
- Conversion of natural gas to H2 of existing gas turbines
- Replacing existing gas turbines by new bespoke ones

Scaling potential and timeline
Short term (2022-2030):
- Existing : 30%-50% by volume (10%-15% by energy)
- New : 100% from 2025-2030 onwards (limited load variations)
- In the short term only hydrogen, no significant ammonia

Long term (2030-2050):
- 100% hydrogen is feasible
- NOx emissions are point of attention as well as load variations
- Ammonia more likely for specific turbines with bespoke technologies (e.g. Mitsubishi has research ongoing)

Maturity
Technology Readiness Level (TRL)

Short term (2022 – 2030):
- **Hydrogen:** Current state of the art is 30% H2 by volume which is ~10% by energy (TRL 7). A multitude of installations that are equipped for hydrogen co-firing are expected for the next few years with OEMs offerings available. Currently OEMs are developing combustors for high percentages co-firing (current TRL 5) which are expected be first commercial at scale somewhere around 2025.
- **Ammonia:** The direct co-firing of ammonia has undergone testing programs (TRL 3), while real prototyping at scale is not expected before 2025. A 100% ammonia in gas turbines is an immature technology (TRL 2).

Long term (2030 – 2050):
New turbines that are specifically designed for 100% hydrogen with low NOx emission levels are likely to be included in OEMs offerings by the end of the decade. Development of turbines on direct combustion of ammonia is not the focus of today, but may come into play in mid-2030.

Accelerating developments
The uptake will strongly depend on the market conditions, incentives or specific local drivers.

Decarbonization opportunities
Hydrogen and hydrogen-derived fuels for power production

GHG reduction potential

Target emission sources
The source is a gas turbine in open cycle or combined cycle mode, applied for power generation (simple cycle, combined cycle or cogeneration), or for gas compression (transport) and (water) injection. In 2019, gas turbines made up 68% (offshore) and 15% (onshore) of total upstream and midstream CO_2 emissions.

Technical reduction potential
It is technically feasible to replace natural gas by hydrogen at volumetric rates in the range of:
- Up to around 15% with minor modifications (safety related, start up fuels)
- Up to 15%-50% depending on turbine type/manufacturer, with major modifications (controls, safety, combustion stability). The timelines for achieving these amounts in individual turbines are project specific as they relate to the need of specific fuels stations, storages, changes in settings and controls, and environmental (permitting) changes.
- Above 50%: Complete replacement of combustors likely required

Specific 100% hydrogen turbines (or upgrades) are under development and will be turbine specific.
For the near term (in the period 2025-2030), based on this analogy, one could assume the potential is up to 15%-50% across the full fleet in case all turbines could implement hydrogen co-firing (5%-15% by energy). This is in line with other estimates, such as from the LowEmission research centre.

Realistic reduction potential
In practice there are various obstacles most notably the available hydrogen infrastructures for platforms and potential impacts on permits for land-based gas turbines. Also the current activities have been executed for a number of turbine models. Eventually, one could assume that the realistic potential as part of the technical potential is in the order of 10%-50%. Market conditions, particularly the price of hydrogen compared to gas+CO_2 cost, has a big impact on the economic viability this potential. In case the residual gas can be used (CO_2 separated and stored), then economics may be more favourable.

Main challenges and opportunities

Development and implementation obstacles
Key considerations for co-firing of hydrogen:
- Cost competitiveness of hydrogen vs natural gas as fuel
- Hydrogen fuel station / storage causing specific safety measures
- For platforms, the need for mooring barges for fuelling
- The tendency for increasing NOx emissions, and as such measures needed to be compliant for NOx regulations and permitting. Water injection is a remediation option. Demin water required.
- The heat rate (or efficiency) is strongly dependent on the turbine load, and varies typically between 30% and 40% depending on load. This ultimately impacts the cost of electricity
- Societal opinion on hydrogen is generally favorable, however, combustion is likely seen as the last resort
- Need for reliability and redundancy is to be considered. Combustion dynamics and flashback are key research items (for high^% co-firing and fluctuating load).
- The minimum load level and risk of flashback
- For ammonia: flame extinction and long flames need redesign for higher % co-firing
- The volumetric calorific value of H2 is three times as low as that of natural gas

Industry opportunities and synergies
- Establishing a market for hydrogen can facilitate faster developments within hydrogen production (both green and blue), hydrogen infrastructure, safety requirements and frameworks.
- Residual gas from operations is currently fired in offshore GTs. In case of offshore CCS of residual gases, this will lead to a hydrogen rich residual gas that enters the turbine and modifications to the turbine are needed.
- For (specific) new generation GTs hydrogen capabilities (e.g. co-firing or 100%) may become the standard post-2030.
- Synergies may be found with industries that have gas fired boilers or hydrogen facilities (SMR).
- Hydrogen can also be used for providing flexibility to offshore wind production through storage and re-electrification, either locally or as part of offshore hubs, such as the Deep Purple concept by TechnipFMC. Although not covered here, this can be of interest if further investigating coordinated electrification or local supply from offshore wind.

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3.2 Decarbonization opportunities
Energy efficiency through reservoir management: Water management

Water-flooding is a widely used technique for pressure maintenance or improving sweep efficiency. Incremental recovery of water-flooding ranges from 15 to 25%. Nonetheless, water-flooding is an energy-intensive activity. Water injection systems typically consume 30 to 50% of field total power consumption. For many oilfields on the Norwegian Continental Shelf (NCS), the percentage is much higher, where more than half of the energy on a platform goes to water injection pumps. Thus, water-flooding significantly contributes to the amount of GHG emission.

Short description

Upstream CO_2 emissions (NCS) per boe increases over the lifetime of the fields on the Norwegian continental shelf. For waterflooded fields CO_2 emissions per boe produced will increase significantly with increasing watercut. Emissions stems from generation of power, heat and flaring.

It is possible to lower the CO_2 footprint significantly by ensuring stable displacement to avoid or sow down water breakthrough. This can be obtained by several different technologies like (not all technologies will work at the different fields)

- Improved reservoir understanding and management.
  - Interwell and inflow tracer applications
- Conformance control at the well or in-depth
  - AICD's, Straddle, Sleeves, Cement, Plugs
- Conformance control in-depth (in reservoir)
  - Gel/Polymers/Smart water
- Downhole water separation and reinjection

Ultimately a combination of these technologies may not be sufficient, and reduction of late-life production should be considered. This will however lead to a significant loss of oil production from the fields, as well as the potential loss of the host/tieback platform functionality. A combination with CCS in field late-life might lead to life extension with new opportunity.

Application scope and scaling potential

Application scope

- All fields under waterflooding on the NCS (and worldwide)
- Water injection optimisation to obtain stable displacement and avoid water breakthrough.
- Smart wells to optimise completion
- Downhole separation for energy efficiency
- Considerable CO_2 emissions reductions potentials for tail-end productions.
- Cost benefit analysis and life-cycle emission effect for high water cut production will be needed.

Scaling potential and timeline

Short term (2022-2030):
Several technologies are available and being use at a varying degree at the NCS. Others needs pilots and/or R&D.

Option for a more than 50% reduction in NCS CO_2 emission – at the cost of 10% lost oil from high-water-producing fields (*).

Long term (2030-2050):
Strong R&D focus on improving modelling & reservoir understanding, in-depth type WSO and near wellbore technologies. Ability to implement and mature several new technologies.

Maturity
Technology Readiness Level (TRL)

Short term (2022 – 2030):
Water management technologies has been widely applied on the NCS and technologies for optimisation has been matured and applied for decades. Full scale utilisation onshore, limited full scale experience offshore on the NCS.
TRL's are ranging from fairly low to commercially available depending on technology, examples

- AICD's are widely used on several fields
- Conformance control at the well are used, but could improve useage.
- Interwell and inflow tracers to identify thief zones are in use today at the NCS, could benefit from further development
- Downhole water separation and injection do need pilot's

Long term (2030 – 2050):
Continued development of existing and new technologies
Draw synergies with CO2 storage

Accelerating developments
Pilots and R&D could speed up implementation

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(*) Reference; Arne Stavland, NORCE, Rystad, Forskningsrådet; Reduksjon av klimagassutslippene fra olje-og gassproduksjon på norsk sokken med 50% innen 2030

3.2 Decarbonization opportunities
Energy efficiency through reservoir management: Water management

GHG reduction potential

Target emission sources
For oil fields, water injection accounts for around 50% of total emissions. In addition, most waterfloods on the NCS are using gas-lift. High water-cut wells do need considerable amounts of gaslift to flow and are hence driving up energy consumption. By either reducing the need for water injection (and gaslift) by optimizing the waterflood or replacing the energy with a less CO_2 intensive energy the emissions can be significantly reduced.

Much is being done on the NCS as of today, but efforts will have to be intensified.

Technical reduction potential
Significant potential from both the optimization of waterfloods as described, expected potential of 15-30% from optimization using a combination of technologies.

Late life production with high water cut: CO_2 emissions reductions from late life wells/fields can be considerable. This needs to be assessed and considered versus the loss of oil production and host facility function (ie smaller tie'ins cannot produce without the host platform)

Realistic reduction potential
Water management technologies are being implemented today, but more can be done. Main obstacle today is the low cost of energy (delivering injection water and gaslift) versus the value of the oil and the costs of implementing the technology.

Main challenges and opportunities

Development and implementation obstacles
Cost:
- Relatively cheap energy (for water injection and gaslift)
- High costs for water displacement technologies.
- A good enough understanding of the issues before performing a water shut off job in a well
    - Ensure sufficient data acquisition up front
- Use of chemicals (polymers) in injection water for stability improvement is environmental unfriendly and costly.
- Downhole separation technologies are available, ESP (Electric Submersible Pump), but not widely used.

Industry opportunities and synergies
- Potential synergies with CCS, particularly for late life oil production
- Export of technology – ongoing today, but with more stringent emission regulation worldwide, it is expected that a larger marked will develop

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3.2 Decarbonization opportunities

Energy efficiency through reservoir management: CO_2 EOR

CO_2 for EOR stands out as a technology that reduces CO_2-emissions substantially whilst increasing petroleum volumes, but it comes with a considerable cost and with a long lead time until improved recovery is realized. On the NCS the availability of CO_2 has been limited. The transportation distance and cost is a limiting factor. CO_2-EOR could be developed in connection with CCS hubs.

Short description

CO_2 Enhance oil recovery (CO_2-EOR): Using CO_2 as a form of secondary or tertiary (after waterflooding) oil recovery mechanism. The primary goal is to improve oil recovery, it is not long-term storage of CO_2. However some CO_2 is stored in the process.

CO_2-EOR has been commercially deployed for decades, but largely onshore.

When CO_2 is injected it is back produced along with reservoir fluids, separated at the surface, and commonly, reinjected/recycled back into the reservoir. The cycle repeats throughout the operation. Max 30% of CO_2 is trapped through residual, solubility and structural trapping over the life time of project (Hosseininoosheri et al., 2018 Permain Basin Analogue USA).

If the remainder of the recycled CO_2 can be injected into the fields after oil project has finished – additional CO_2 can be stored. Overall the CO_2 mass balance calculations increase if the remaining CO_2 left after final oil production can be safety and permanently reinjected and stored in the depleted oil field.

CO_2-EOR extends the life of existing infrastructure and maximise production in a mature Hydrocarbon basins, where exploration cost may be increases and success rates are lowering

Application scope and scaling potential

Application scope
CO_2-EOR has been commercially deployed for decades, but largely onshore. CO_2-EOR does occur offshore in Brazil (Petrobras -Lulu field 2011).

On the NCS the availability of CO_2 has been limited. The transportation distance and cost is a limiting factor.

Scaling potential and timeline
Short term (2022-2030): Scaling and deployment is linked to suitable reservoirs for CO_2-EOR and supply of CO_2. Key challenges are high CAPEX and OPEX cost of conducting CO_2-EOR offshore.

Long term (2030-2050):
Linked to finial incentives and ability to lowering CAPEX and OPEX cost of conducting CO_2-EOR offshore

Maturity

Technology Readiness Level (TRL)

Short term (2022 – 2030):
TRL – mature
NPD screened 23 oil fields on NCS for CO_2-EOR would improve oil recovery between 4-12% (Lindeberg et al., 2017)

Long term (2030 – 2050):
Develop CO_2-EOR in connection with CCS hubs

Accelerating developments
- 45 Q style finial incentives for CO_2-EOR
- Cost-sharing of CO_2 pipeline networks
- Smart and cost efficient topside solutions for processing CO_2-rich fluids, subsea technologies for separation and injection of CO_2, as well as solutions for improved mobility

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3.2 Decarbonization opportunities

Energy efficiency through reservoir management: CO_2 EOR

GHG reduction potential	Main challenges and opportunities
Target emission sources CO_2 for EOR stands out as a technology that reduces CO_2-emissions substantially whilst increasing petroleum volumes, but it comes with a considerable cost and with a long lead time until improved recovery is realized. There is a need for continued efforts to develop and apply methods and technologies for improved subsurface understanding.	**Development and implementation obstacles** Cost:. • High CAPEX and OPEX cost of conducting CO_2 EOR offshore • Significant investment in pipeline, topside and well cost are required Technical: • Identifying suitable large scale reservoirs for CO_2-EOR and supply of CO_2 at low cost Availability of CO_2 and transportation costs
Technical reduction potential CO_2-EOR; Hard to identify update information – latest data found 2017 Pure CCS will store more CO_2 than CO_2 EOR (CCUS)	**Industry opportunities and synergies** ▪ 45 Q style finial incentives for CO_2-EOR ▪ Cost-sharing of CO_2 pipeline networks ▪ Smart and cost efficient topside solutions for processing CO_2-rich fluids, subsea technologies for separation and injection of CO_2, as well as solutions for improved mobility ▪ Develop CO_2-EOR in cooperation with CCS hubs
Realistic reduction potential Most promise on large fields where it is economically beneficial to do CO_2 EOR.	

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3.2 Decarbonization opportunities

Energy efficiency through reservoir management: Artificial intelligence

Machine learning and (data management) are the two main sub division of artificial intelligence (AI) science. The aim of ML is to speed up complex decision making and create more efficient planning. Potentially saving time money and likely emissions.

Short description

Machine learning – computers systems learn from and interpret data without human input.
Digitalisation – complying physical data in an easy to use digital that can easily accessed and used

ML - be applied to well trajectory planning (Ability to generate multiple well paths faster to provide different options to decision makers), portfolio planning, rig sequence management, decommission planning to reduce OPEX. Additional many attempts have been applied to seismic interpretation to speed up exploration prosect identification.

Digitization – faster access to data to improve techanical workflow

All major oil companies e.g. Shell, BP, Equinor have departments dedicated to finding new and innovative ways to speed up decision macking to reduce cost

Application scope and scaling potential

Application scope
Most value in oil & gas planning activates where there are competing options and ML can provide multiple scenarios for planners and decision makers to choose between

Digitalisation of data can significantly speed up the delivery of subsurface (e.g. model building, development planning) and engineering workflows

Equinor technology strategy 2019 predicted
Automated drilling – 15% cost reduction
Future fields – 30% capex reduction & 50% opex reduction

DNV GL 2020 estimates: Drilling cost reduction; 3-4 bNOK/year ▪ GHG reduction of 0.06 Mega ton, representing 6% of drilling activities release (1.06 Mega ton)

Scaling potential and timeline
All major E&P companies have been investing heavily in AI for more than a decade. This is a fast developing field. Impact is still uncertain.

Maturity

Technology Readiness Level (TRL) and Commercial Readiness Index (CRI)

Short term (2022 – 2030):
Currently being applied to assest in the North Sea
All the major oil companies operating in the NCS have AI strategies e.g. Equinor, Shell etc..
The maturity of the different application varies and is hard to put a TRL level on it

Long term (2030 – 2050):
- AI – will dominate technology development for the foreseeable future
- Will be applied more widely as computer programs become more sophisticated – level of impact still uncertain (Equinor technology strategy

Accelerating developments

- E&P partner with niche IT companies and training staff to be more digitally aware
- Build trust in NL solutions
- Better QAQC of data used in AI applications

3.2 Decarbonization opportunities
Energy efficiency through reservoir management: Artificial intelligence

GHG reduction potential

Target emission sources
More efficient delivery of process and technical delivery will reduce emissions directly and indirectly. Largest impact is likely on scope 1 emissions

Technical reduction potential
BCG 2021 PREDICTS : 15% could be abated economically through improvements in operational and energy efficiency – this is overall estimated, not specific to reservoir management

Realistic reduction potential
Difficult to find data on this, to be discussed.

Main challenges and opportunities

Development and implementation obstacles
(key words: technical, costs, regulatory/political/societal)

- Technical and skill set: Training staff to be more digitally aware and investing in the latest AI solutions
- Communication and data transfer between multiple IT systems
- There is lack of trust in ML models and outputs
- Diligent management of data quality is needed for ML to succeed
- Machines can not replace humans in all operations
- Impact is still uncertain

Industry opportunities and synergies

E&P companies – making smart partnerships with IT and digitisation specialists – this is currently happening

Sharing lessons learned, successful ML algorithms, case studies, etc. for accelerated learning and ML adoption - this is more likely to happen for Environmental monitoring b) Energy efficiency c) Maintenance optimization / integrity management (DNV GL OG 21 report)

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3.2 Decarbonization opportunities
Optimized gas turbines: Waste heat recovery

One approach for reducing emissions from gas turbines is to improve the total energy efficiency through waste heat recovery. The waste heat from the gas turbine can be utilised in a waste heat recovery unit (WHRU) to cover the heat demand of the installation. Alternatively the waste heat can be used to produce steam in a heat recovery steam generator (HRSG). The steam can then be used in a bottoming cycle to produce more electricity or in a steam injection gas turbine cycle (STIG).

Short description

- **Waste heat recovery unit (WHRU)** - Recovering of waste heat from the hot turbine exhaust to cover the installations heat demand and thus improving the total energy efficiency. WHRU is a proven and widely used technology.
- **Combined cycle** - The hot turbine exhaust can also be utilized in a heat recovery steam generator coupled with a steam turbine. The number of gas turbines needed to cover the power demand will be reduced enhancing the fuel utilization. However, the available heat is reduced, and the heat demand might need to be covered by other sources such as heaters. The installations specific demand heat and power will therefore influence the suitability.
- **Steam injection gas turbine cycle (STIG)** - The hot turbine exhaust can also be utilized in a heat recovery steam generator and the generated steam is injected in the combustion chamber of the gas turbine after the compressor outlet, resulting in an increased power output in the turbine whereas the compression work maintains constant and thereby improving the thermal efficiency. However, the available heat is reduced, and the heat demand might need to be covered by other sources such as heaters. The installations specific demand heat and power will therefore influence the suitability.

Application scope and scaling potential

Application scope
The solutions will improve the energy efficiency of the gas turbine system of the installation. For combined cycle it applies to gas turbines for power generation.

Scaling potential and timeline
Short term (2022-2030):

- **WHRU** – Is a proven and widely used technology. Can be implemented on a shorter term, but is probably already assessed for many installations.
- **Combined cycle** – Requires a lot of space and adds a lot of weight, so requires major upgrade for brownfield operations. Mainly considered for greenfield. Limited potential in the short term.
- **STIG** - Requires a lot of space and adds a lot of weight, so requires major upgrade for brownfield operations. Mainly considered for greenfield but still issues to solve. Limited potential short term.

Long term (2030-2050):

- **WHRU** – Same as for short term
- **Combined cycle** – On a longer term, combined cycle could have an impact in reducing emissions from gas turbines
- **STIG** – On a longer term, STIG could have an impact in reducing emissions from gas turbines, but limited compared to combined cycle.

Maturity
Technology Readiness Level (TRL) and Commercial Readiness Index (CRI)

Short term (2022 – 2030):

- **WHRU –** TRL 7
- **Combined cycle –** TRL 7 (Installed on Oseberg, Snorre and Eldfisk)
- **STIG –** TRL 5 (Only onshore applications)

Long term (2030 – 2050):

- **WHRU** – TRL 7
- **Combined cycle** – TRL 7
- **STIG –** TRL 5 / 6

Accelerating developments
For the technologies with lower TRL, demonstration in offshore applications is a means of accelerating the developments. Development of more compact solutions would also make uptake in the offshore industry more attractive.

3.2 Decarbonization opportunities
Optimized gas turbines: Waste heat recovery

GHG reduction potential

Target emission sources
The source is a gas-fired turbines. These are Scope 1 emissions. Considering a total (2020) upstream and midstream CO_2 emissions of 13.2 Mt CO2 turbines on platforms make 72% (i.e. ~9,5 Mt) and turbines on-shore make 16% (~2 Mt) of that. Gas turbines are applied for power generation, or for gas compression (transport) and (water) injection. For combined cycle it targets gas turbines for power generation.

Technical reduction potential
- **WHRU** – The reduction potential will depend on the heat demand of the installation. But the emissions could be reduced up to 20 %.
- **Combined cycle** – The electrical efficiency will go from around 38% to 51%, which would reduce the CO_2 emissions by around 25%. However, the number would be lower depending on the heat demand.
- **STIG** - The electrical efficiency will go from around 38% to 51%, which would reduce the CO_2 emissions by around 25%. However, the number would be lower depending on the heat demand.

Realistic reduction potential
- **WHRU** – WHRU is already implemented on many installation, so this measure will have a limited additional on the emissions on NCS.
- **Combined cycle** – Could be challenging to retrofit due to space and weight challenges, so mainly valid for newbuilds.
- **STIG** - Could be challenging to retrofit due to space and weight challenges, so mainly valid for newbuilds.

Main challenges and opportunities

Development and implementation obstacles
(key words: technical, costs, safety, regulatory/political/societal)
- **WHRU** – proven and widely used technology
- **Combined cycle** – Challenges include weight and size, compared to a single cycle gas turbine both weight and footprint will roughly double. The heat demand must also be assessed as this can make the option less attractive compered to a WHRU.
- **STIG** – As for the combined cycle, the challenges include challenges include weight and size, compared to a single cycle gas turbine both weight and footprint will roughly double. In addition, large amounts of treated make-up water (boiler water quality) is needed, adding treatment facilities and storage requirements. The heat demand must also be assessed as this can make the option less attractive compered to a WHRU.

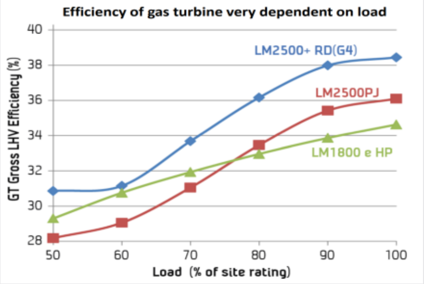
Industry opportunities and synergies
- WHRU, combined cycle and STIG are already established technologies with limited opportunities for industrial development in Norway.

3.2 Decarbonization opportunities
Optimized gas turbines: Utilization

Many offshore gas turbines on the NCS run at 50-60% load, some at 70-80%, leading to low efficiencies. Improving the load of the gas turbine can be done by replacing a large turbine with multiple smaller units that can be switched on and off depending on the load, another way is to add batteries to handle load fluctuations allowing the gas turbine to run on a higher load, a hybrid set-up.

Short description

- **Multiple units** – By having multiple gas turbines it is possible to better adapt to load variations while maintaining a high load factor of the individual gas turbine, i.e. being able to cut the use of a turbine instead of just reducing the load factor
- **Batteries** – Adding a battery pack can make it possible to run the gas turbine on high load over the lifetime, with additional advantages such as: (1) Battery as stand by, (2) eliminates load transients, (3) eliminates load variations. Batteries can fast deliver power to the grid, covering peaks in the demand, while base loads are served by the gas turbines.



[1]

Application scope and scaling potential

Application scope
The solutions will improve the energy efficiency of the gas turbine system of the installation through improvement of the load factor. For batteries it applies to gas turbines for power production.

Scaling potential and timeline
Short term (2022-2030):
- **Multiple units –** Readily available technology, but requires major upgrade of brownfield
- **Batteries –** Readily available technology, but with limited use in offshore applications. NCM (Nickel, Manganese, Cobalt) and LFP (Lithium Iron Phosphate) are the most common types in maritime applications. Requires space and adds weight which limits the uptake in the short for brownfield applications.

Long term (2030-2050):
The technologies are mature and commercially available and should be considered for new developments – they can be retrofitted on existing installation if there are no space and load limitations and should be considered during major upgrades.

Maturity
Technology Readiness Level (TRL) and Commercial Readiness Index (CRI)

Short term (2022 – 2030):
- **Multiple units –** TRL 7
- **Batteries –** TRL 5 (application has been tested in other marine application such as shipping, but limited use in offshore installations)

Long term (2030 – 2050):
- **Multiple units –** TRL 7
- **Batteries –** TRL 6 (Will likely be tested before 2030)

Accelerating developments
For the technologies with lower TRL, demonstration in offshore applications is a means of accelerating the developments. Development of more compact solutions would also make uptake in the offshore industry more attractive.

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[1] Marit Mazzetti, OTC-24034-MS

3.2 Decarbonization opportunities
Optimized gas turbines: Utilization

GHG reduction potential

Target emission sources
The source is a gas-fired turbines. These are Scope 1 emissions. Considering a total (2020) upstream and midstream CO_2 emissions of 13.2 Mt CO2 turbines on platforms make 72% (i.e. ~9,5 Mt) and turbines on-shore make 16% (~2 Mt) of that. Gas turbines are applied for power generation (simple cycle, combined cycle or cogeneration), or for gas compression (transport) and (water) injection. For batteries it targets gas turbines for power generation.

Technical reduction potential
- **Multiple units –** The reduction potential will depend on the that the gas turbine is operating on. Studies indicate that update 5% can be saved by running the gas turbines closer to full load. [1]
- **Batteries –** The reduction potential will depend on the individual load curves. Some studies indicate that 5-10% CO_2 reduction is achievable.

Realistic reduction potential
- **Multiple units** – Could be challenging to retrofit due to space and weight challenges, so mainly valid for newbuilds.
- **Batteries** – Could be implemented on different scales and for different applications. Due to weight and volume, in retrofit applications, up to 5% CO_2 reduction is probably more realistic to achieve.

Main challenges and opportunities

Development and implementation obstacles
(key words: technical, costs, safety, regulatory/political/societal)
- **Multiple units –** More turbine might require more space and more maintenance. However, if a you can cut a turbine in normal operations, availability could increase since maintenance of turbines can be done without shutting down production.
- **Batteries** – Batteries are heavy and voluminous. For example, 1 MWh of NCM battery system weighs around 10 tons (depending on detailed chemistry and packing).

Industry opportunities and synergies
- Use of batteries on NCS could create an additional user for the growing battery industry and make Norway a more attractive location for development and production of batteries and associated technology.

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[1] Marit Mazzetti, OTC-24034-MS

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3.2 Decarbonization opportunities
Geothermal energy to reduce electrical power demand offshore

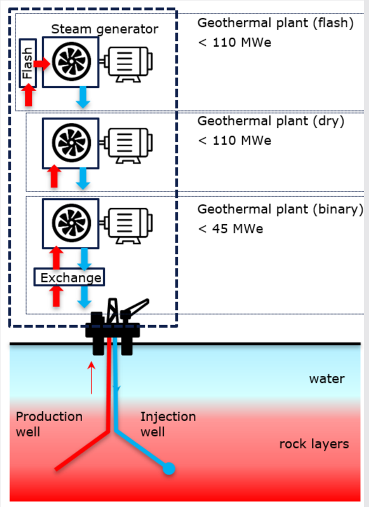
Geothermal energy can be used to generate electricity for self consumption by platforms or for third parties reducing the GHG up to 100% for that specific power production. Geothermal power is a proven technology deployed onshore with over 15 GWe in operation worldwide. It is expected that there is great potential for offshore geothermal power plants since it is possible to re-use existing or abandoned oil and gas wells and platforms. However offshore geothermal power plants is not operational at this moment and needs to be explored in the coming years to understand its potential.

Short description

A conventional geothermal system consists of two wells (production and injection well). Heat from the deep subsurface is extracted by circulating the geothermal brine in a closed loop system.

Geothermal heat can be applied for electricity production using:

1. Flash steam (>~180°C).
2. Dry steam plants.
3. Binary (~90-180°C) (ORC).



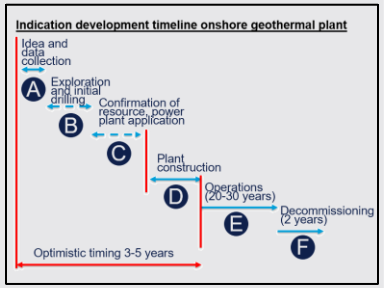
Note: In stead of a two well system, single borehole heat exchangers are available. A mono well then acts as production and injection well. First estimates on thermal output are several 100's kWth, which is considerably lower than the geothermal doublet system (of several 10's MWth)

Application scope and scaling potential

Application scope

1. Production of electricity (for self consumption or third party use).
2. Production of thermal energy for self consumption of processes at the platform.
3. Re-use abandoned well from dry oil/gas wells for geothermal energy
4. Potential coproduction of geothermal-energy from oil or gas recovery processes.

Scaling potential and timeline



- Concept Development Process for first demonstration projects
- Step B+C will be shortened by using existing geological knowledge from OG production (decrease drilling risk)

Long term (2030-2050): proven concept and working towards more standardized solutions for geothermal plants using platforms.

Maturity
Technology Readiness Level (TRL)

Short term (2022 – 2030):
Well technology : TRL 7 (onshore)
Conversion technologies (onshore):
- ORC/Rakine: TRL 7
- Flash: TRL 7
- Over 15.000 MWe realised worldwide

Offshore geothermal: TRL 2 to 4

Long term (2030 – 2050):
- TRL 7 concepts for offshore geothermal plants

Accelerating developments
- Cope with decarbonization requirements
- Research projects off shore geothermal energy: North Tech Energy (NTE), Transmark Renewable; SINTEF and Iceland Geosurvey (ISOR).
- Reusing wells for geothermal energy postpones well abandoned and increase well lifetimes.
- Significant lower drilling cost compared with onshore geothermal energy.

3.2 Decarbonization opportunities
Geothermal energy to reduce electrical power demand offshore

GHG reduction potential

Target emission sources
A) Providing electricity to onshore electricity grid
B) Increasing operational platform efficiency: Replacing (partial) gas turbines at platforms by geothermal power plants. Geothermal plants use some electricity to operate (e.g. ESP-pumps, cooling tower), however this can be 'geothermal – electricity' and so reduce up to 100% of the CO2 emissions.

Technical reduction potential
Potential for per geothermal power plant. Typically a
- geothermal binary technology provides 2-3 MWe [2]
- geothermal a flash or dry steam technology provides 17 tot 23 MWe [2].

Note 1) this potential for geothermal energy is based on worldwide existing geothermal plants, and has no direct relation with specific local Norwegian geothermal potential. However the ranges show a first indication of typcal power plant sizes.

Note 2) in case of "increasing operational platform efficiency' gasturbines on the platform can be replaced by geothermal electricity. For this a reference case of 80 MWe / platform could be used (4 x 20 MWe gasturbine per platform [1])

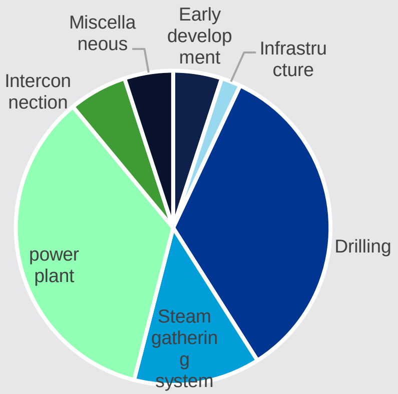
Realistic reduction potential
Requirements for deployment of offshore geothermal energy:
- Geological conditions and subsurface temperatures/flowrates available.
- Platform should be suitable for the construction of geothermal plant (conversion technology)
- A platform in use or close to shore for power distribution if abandoned.

Main challenges and opportunities

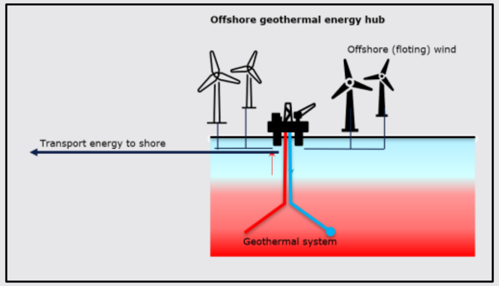
Development and implementation obstacles

1. Availability of thermal aquifer systems nearby the offshore platform with good conditions for geothermal energy (high temperature, high mass flowrates).
2. A offshore geothermal well design or repurpose OG-well (e.g. casings, insulation, well heads, tubing)
3. Cope with the harsh offshore environment (salt, current, wind, water etc.).
4. Return on investment of geothermal plant compared to platform lifecycle.
5. Subsea electricity cables needed in case of transport to shore.
6. Permits and licensing (exploration + exploitation, environmental, grid access).
7. Installation of technical room(s) at platform.
8. Low drilling cost compared to onshore geothermal plants (see picture on the right, where drilling is significant),

Typical onshore geothermal power plant (CAPEX)



Industry opportunities and synergies
- Extend lifetime of wells and platforms: use existing platforms and repurpose oil/gas wells for geothermal heat/electricity.
- Provide geothermal energy for platform operation efficiency decarbonization
- Create a offshore geothermal power hub: Geothermal energy hub at sea (e.g. for H2 production, grid connection to shore, (floating)-wind turbines connected to this energy hub; local off shore geothermal electricity)



[1] Overview gas turbines Norway: https://no.wikipedia.org/wiki/Liste_over_gasskraftverk_i_Norge
[2] Calculation by DNV based on source: Efficiency of geothermal power plants: A worldwide review

4. Prioritizing most promising opportunities

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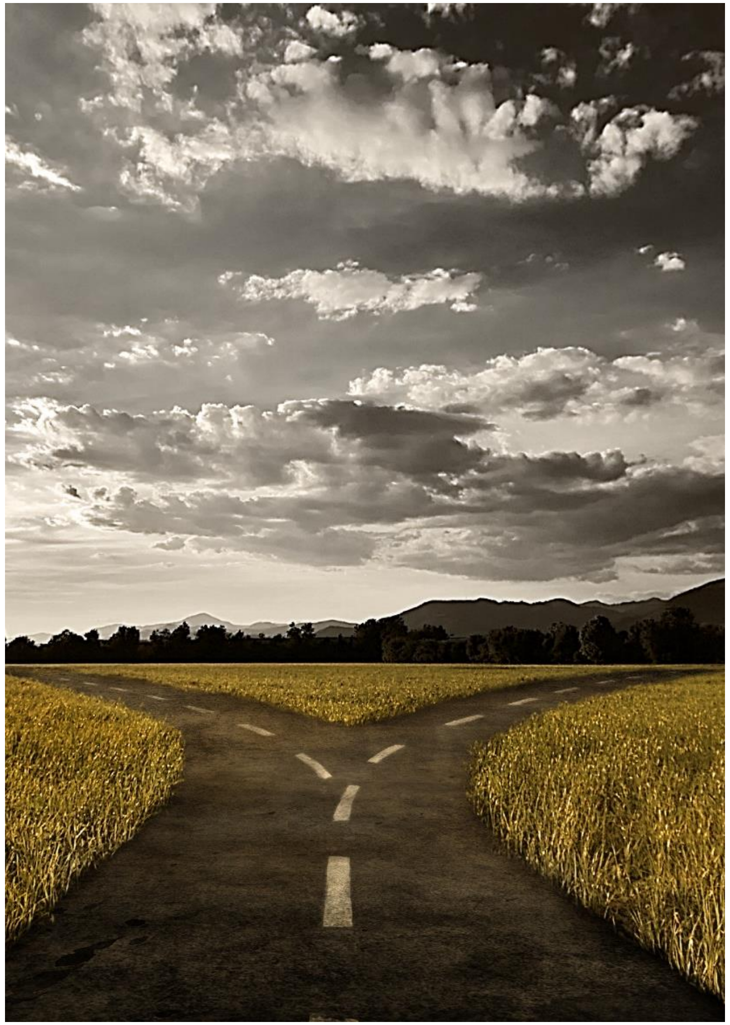
4.1 Introduction to approach



- **Technology comparison approach:** Assessing the scope of various technologies to support the NCS in meeting near- and long-term GHG emission reduction targets has been a key part of the first phase of this project. This assessment has been undertaken through an iterative process whereby DNV experts have assessed the various technologies across a set of screening criteria presented in the tables in the following slides, with opinions having been informed and qualified through input provided by OG21 experts through technology assessment workshops with all five OG21 Technology Groups.
- **Scoring methodology:** Technologies have accordingly been scored by applying a "high", "medium" or "low" traffic light methodology by technology across the set of criteria listed – whereas high is the most positive and low is the most negative. The aim behind this methodology is to take a holistic view on their overarching potential of each technology, as well as to specifically identify and visualise potential barriers and opportunities. Note that some technologies have been divided into sub-technologies, e.g. for water management and electrification, in order to give a more accurate scoring.
- **Shortlist:** On the basis of this scoring, the long-list of technologies will be shorted to constitute some technologies that qualify for a deeper-dive in the second stage of the project. **It is important to note that although some technologies are not part of the deep-dive in this project, this does not mean that DNV does not see a potential for scaling these technologies offshore.**

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High	Medium	Low

4.2 Comparing opportunities

Decarbonization opportunity for Scope 1 emissions	Application scope	Screening criteria						Additional comments
		Maturity High: TRL 6-7 Medium: TRL 4-6 Low: TRL <4	**Scale-up timeline** High: Before 2030 Medium: 2030 – 2035 Low: After 2035	**Main development and implementation obstacles** High: Limited obstacles Medium: Obstacles that are solvable in the short term Low: Substantial obstacles not solvable in the short term	**Industry opportunities** High: Clear and important opportunities Medium: Possibly important opportunities, but less clear Low: Little opportunities	**Realistic GHG emission reduction potential (total NCS)** High: >55% Medium: 30-55% Low: <30%	**Synergies with Scope 3** High: Clear and substantial scope 3 synergies Medium: Some scope 3 synergies Low: Limited scope 3 synergies	
Electrification: Coordinated from onshore power grid	Replacing gas turbines (partial or full electrification)	Already existing (Johan Sverdrup phase II)	Dependent on onshore capacity	High costs (shut-down) for brownfield, in particular for replacing direct drives. Social acceptance, onshore capacity	Opportunities for Norwegian Yards (AkerSol, Aibel), cable OEM (Nexans), OEMs like NKT, Hitachi/ABB have strong Nordic presence.	Brownfield limitations (space, weight, Hz). Depends on partial or full electrification	Synergies by increasing competence, value chain and industry development.	Enables cost optimization.
Electrification: Coordinated from offshore power grid	Replacing gas turbines (partial or full electrification)	Existing technology, new application	Requires significant regulatory developments and coordination	Regulations unclear, coordination between countries	Opportunities for Norwegian Yards (AkerSol, Aibel), cable OEM (Nexans), OEMs like NKT, Hitachi/ABB have strong Nordic presence.	Brownfield limitations (space, weight, Hz). Depends on partial or full electrification	Synergies by increasing competence, value chain and industry development.	Can be supplied from various power sources, high potential but in longer term
Electrification: Individual (radial) from onshore power grid	Replacing gas turbines (partial or full electrification)	Already existing	Dependent on onshore capacity	High costs (shut-down) for brownfield, in particular for replacing direct drives. Social acceptance, onshore capacity	Limited opportunities for industry	Brownfield limitations (space, weight, Hz). Depends on partial or full electrification	Synergies by increasing competence, value chain and industry development.	Limited potential for optimization.
Electrification: Local supply from offshore wind	Replacing gas turbines (partial electrification)	Hywind Tampen	Requires regulatory clarifications	Regulations unclear, supply chain developments	Norway taking lead in global floating wind developments	Depends on back-up solution	Synergies by increasing competence, value chain and industry development.	Offshore wind high synergy with scope 3 as complete switch to renewable H2 and NH3

4.2 Comparing opportunities

High	Medium	Low

Decarbonization opportunity for Scope 1 emissions	Application scope	Screening criteria						Additional comments
		Maturity High: TRL 6-7 Medium: TRL 4-6 Low: TRL <4	**Scale-up timeline** High: Before 2030 Medium: 2030 – 2035 Low: After 2035	**Main development and implementation obstacles** High: Limited obstacles Medium: Obstacles that are solvable in the short term Low: Substantial obstacles not solvable in the short term	**Industry opportunities** High: Clear and important opportunities Medium: Possibly important opportunities, but less clear Low: Little opportunities	**Realistic GHG emission reduction potential (total NCS)** High: >55% Medium: 30-55% Low: <30%	**Synergies with Scope 3** High: Clear and substantial scope 3 synergies Medium: Some scope 3 synergies Low: Limited scope 3 synergies	
Gas power hubs with CCS (offshore)	Replacing gas turbines (partial or full electrification) where direct electrification is difficult	Existing technology, but not applied offshore (Medium)	Needs offshore testing, complex value chain (Low)	Cost of power hub, development of value chain, maintenance, access to storage (Low)	Norway taking lead in CCS value chains, benefiting from Northern Lights (High)	Assumes used on fields not reachable from shore due to high costs (Medium)	Reducing category 11 emissions (assuming gas comes from companies on NCS) (High)	Can be part of hub for coordinated electrification, increasing scope 2 emissions compared to electrification from onshore grid
Gas power hubs with CCS (onshore)	Replacing gas turbines (partial or full electrification)	Existing technology (High)	Needs value chain development, possible before 2030 if attached to Northern Lights (Medium)	Political and societal acceptance, development of value chain, access to storage (Medium)	Norway taking lead in CCS value chains, benefiting from Northern Lights (High)	Brownfield limitations (space, weight, Hz). Depends on partial or full electrification. (High)	Reducing category 11 emissions (assuming gas comes from companies on NCS) (High)	Can be part of individual and/or coordinated electrification, increasing scope 2 emissions compared to electrification from onshore grid

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High	Medium	Low

4.2 Comparing opportunities

Decarbonization opportunity for Scope 1 emissions	Application scope	Screening criteria						Additional comments
		Maturity High: TRL 6-7 Medium: TRL 4-6 Low: TRL <4	**Scale-up timeline** High: Before 2030 Medium: 2030 – 2035 Low: After 2035	**Main development and implementation obstacles** High: Limited obstacles Medium: Obstacles that are solvable in the short term Low: Substantial obstacles not solvable in the short term	**Industry opportunities** High: Clear and important opportunities Medium: Possibly important opportunities, but less clear Low: Little opportunities	**Realistic GHG emission reduction potential (total NCS)** High: >55% Medium: 30-55% Low: <30%	**Synergies with Scope 3** High: Clear and substantial scope 3 synergies Medium: Some scope 3 synergies Low: Limited scope 3 synergies	
Compact top-side CCS			Complex value chain, in particular for transport and storage.	High costs (shut down), low CO_2 volumes for transport and storage, development of value chain	Possible development of value chains and new technology, but unknown market potential	Likely applicable for only a few installations on the NCS	No synergies	Weight constraint on most installations.
Hydrogen and hydrogen-derived fuels for power production		Co-firing possible, developments needed for 100% hydrogen. Ammonia still low maturity.	Assumes safety issues are solved, and market for hydrogen/ammonia.	High costs, available infrastructure, low efficiency, safety issues	Potential for leading role in developments of hydrogen and derivatives	Highly dependent on application scale	Significant scope 3 synergies if blue hydrogen/ammonia is produced on the NCS	Possibility of using hydrogen as storage medium for offshore wind
Optimized gas turbines – combined cycle	Improving gas turbine efficiency			Brownfield (weight, size), heating demand needs to be addressed, costs for shut-down	Existing industry	Low technical reduction potential	No synergies	Mostly relevant for greenfield
Optimized gas turbines - STIG	Improving gas turbine efficiency		Water treatment system not implemented offshore	Brownfield (weight, size), heating demand needs to be addressed, costs for shut-down	Existing industry	Low technical reduction potential	No synergies	Mostly relevant for greenfield

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4.2 Comparing opportunities

High	Medium	Low

Decarbonization opportunity for Scope 1 emissions	Application scope	Screening criteria						Additional comments
		Maturity High: TRL 6-7 Medium: TRL 4-6 Low: TRL <4	**Scale-up timeline** High: Before 2030 Medium: 2030 – 2035 Low: After 2035	**Main development and implementation obstacles** High: Limited obstacles Medium: Obstacles that are solvable in the short term Low: Substantial obstacles not solvable in the short term	**Industry opportunities** High: Clear and important opportunities Medium: Possibly important opportunities, but less clear Low: Little opportunities	**Realistic GHG emission reduction potential (total NCS)** High: >55% Medium: 30-55% Low: <30%	**Synergies with Scope 3** High: Clear and substantial scope 3 synergies Medium: Some scope 3 synergies Low: Limited scope 3 synergies	
Optimized gas turbines – multiple turbines	Improving gas turbine efficiency			Brownfield (weight, size), costs for shut-down	Existing industry	Low technical reduction potential	No synergies	
Optimized gas turbines - batteries	Improving gas turbine efficiency			Brownfield (weight, size)	Focus on battery industry in Norway	Low technical reduction potential	No synergies	Possibility of placing batteries sub-surface
Water management for stable displacement (w/o chemicals)			Mature technology already applied today	High costs	Existing technology	Only applicable for oil fields. Dependent on case by case and technology choice.	No synergies	Water injection is a mature technology, improvement through AI and well technology
Water management for stable displacement (w/ chemicals)			Applied onshore, more obstacles to be solved for offshore usage	Chemicals environmental risk, high costs	Possibility of leading R&D and implementation globally	Only applicable for oil fields. Dependent on case by case and technology choice.	No synergies	
Water management for high water cut				Area considerations, high costs	Well technology opportunities	Only applicable for oil fields. High potential for end-of-life brownfield.	No synergies	Downhole water management, well technologies

DRAFT

High | Medium | Low

4.2 Comparing opportunities

Decarbonization opportunity for Scope 1 emissions	Application scope	Screening criteria						Additional comments
		Maturity High: TRL 6-7 Medium: TRL 4-6 Low: TRL <4	**Scale-up timeline** High: Before 2030 Medium: 2030 – 2035 Low: After 2035	**Main development and implementation obstacles** High: Limited obstacles Medium: Obstacles that are solvable in the short term Low: Substantial obstacles not solvable in the short term	**Industry opportunities** High: Clear and important opportunities Medium: Possibly important opportunities, but less clear Low: Little opportunities	**Realistic GHG emission reduction potential (total NCS)** High: >55% Medium: 30-55% Low: <30%	**Synergies with Scope 3** High: Clear and substantial scope 3 synergies Medium: Some scope 3 synergies Low: Limited scope 3 synergies	
Energy efficiency – CO2-EOR				Availability of CO_2, CCS infrastructure, not applied offshore on NCS	Limited opportunities (apart from CCS hubs)	Limited reduction potential	Some (limited) possibility of storing CO_2 from other fields, but controversial whether this reduces scope 3 emissions.	Possibility of increased production
Energy efficiency – artificial intelligence				Data management evolving, machine learning less so, cannot replace humans with regards to HSE	Potential can be very high	Limited reduction potential, more relevant for improving process efficiencies	No synergies	Wide application area, difficult to assess potential
Geothermal energy		Mature technology onshore, less mature offshore.	Project realization in 3-5 years onshore. Demonstration projects can form a basis for plant design for scale up.	Explore and map geological potential, offshore geothermal plant design to de defined and tested.	Potential for being leading within offshore geothermal, potential for connecting to shore	Geothermal power can be self sustaining to achieve high emission reductions, but application potential uncertain	No synergies	

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4.3 Short-listed opportunities for reducing scope 1 emissions

Based on the initial screening and comparison of opportunities, the table below lists the opportunities that are chosen for a deeper-dive in Phase 2 of the project.

Decarbonization opportunity	Part of short-listed opportunities for Phase 2?	Reasoning
Electrification: Coordinated, individual and local supply	Yes	• Electrification from the onshore power grid and through local supply from offshore wind are seen as two of the most mature and "low-hanging" fruits towards 2030, with a high potential for emission reduction. • Local supply through offshore wind could help develop a Norwegian offshore wind industry, with the possibility of combining with other emerging technologies for increased security of supply and reduced emissions, such as hydrogen. • A coordinated build-out can provide benefits in terms of optimization and cost reductions. • In the longer term, a 30 GW target of offshore wind in Norway (2040) plus 150 GW from NL/BE/DK/DE (2050, 60 GW in 2030) will likely result in a massive offshore grid in the North Sea and Norwegian Sea that offshore O&G platforms could connect to. Moreover, this could facilitate a connection of local offshore wind power by the platforms to the main grid, providing electricity during surplus hours. For Phase 2, electrification is treated as one common group, where the different opportunities are discussed and compared.
Gas power with CCS: Onshore, offshore and compact top-side	Yes	• Onshore: Decarbonising onshore gas power plants, with offshore CO_2 storage is a good opportunity to decarbonise large point emitters and contribute with increasing power capacity onshore to enable electrification of the NCS. • Offshore: Offshore power hubs with offshore CCS could be costly compared to onshore gas power with CCS, however could enable electrification of assets that are too far from shore for electrification from shore. • Compact top-side: Challenges related to cost and technical limitations (weight and space), and would likely be possible for only a few brownfield assets. However might provide benefits through decarbonising assets that are difficult to electrify, such as direct-driven compressors. For Phase 2, gas power with CCS is treated as one common group, where the different opportunities are discussed and compared.
Energy efficiency: Water management	Yes	Mature technology with potential for substantial energy savings, and as such high CO_2 reductions.

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4.3 Short-listed opportunities for reducing scope 1 emissions

The table below lists the opportunities that were not chosen for a deep-dive in this project, and have been screened out for various reasons, including costs, maturity, scaling potential and timeline, and application volume. It is important to note that although these opportunities are not part of further assessments in this project, they can still have a high potential offshore – either for reducing emissions that are hard-to-abate through other measures, or in the longer term.

Decarbonization opportunity	Part of short-listed opportunities for Phase 2?	Reasoning
Hydrogen and hydrogen-derived fuels for power production (gas turbines)	No	Hydrogen for power production through gas turbines has a low maturity and challenges related to safety, costs and available infrastructure in the short term towards 2030. However, hydrogen and its derivatives could have a substantial potential in the longer term, especially for providing flexibility to offshore wind production or as part of a larger offshore grid system. Being part of scaling the hydrogen economy could lead to important opportunities for the O&G industry. As such, DNV believes this should be investigated further, but due to its limited potential for power production through gas turbines in the shorter term, hydrogen is not included for reducing scope 1 emissions in Phase 2 of this project. It is however part of the potential for reducing scope 3 emissions, see following chapter.
Optimized gas turbines: Waste heat recovery and optimizing utilization	No	Waste heat recovery: WHRU is implemented on many installations already. Combined cycle and STIG requires a large footprint and adds weight, mainly relevant for greenfield. Heat vs power demand needs to be considered. Optimizing utilization: Requires major rebuild with limited emission reduction potential. For batteries, if they can be placed subsea it could be an attractive solution.
Energy efficiency: CO_2-EOR	No	Limited opportunities, limited access to infrastructure, substantial costs, limited emission reduction potential.
Energy efficiency: Artificial intelligence	No	Limited direct emission reduction potential.
Geothermal energy	No	High costs and limited potential for geothermal energy to reduce emissions through electrification offshore.

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5. Scope 3 considerations

Securing future value for Norwegian oil and gas/energy industry

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5.1 Scope 3 considerations
Scope 3 reporting pressures increasing

Scope 3 pressures emerging

EU Corporate Sustainability Reporting – Tightening reporting requirements:

- The EU Corporate Sustainability Reporting Directive will require reporting and tracking of sustainability information throughout the value chain.
- The Project Task Force on European sustainability reporting standards, which will provide general principles on how to report under the CSRD, requires reporting of full scope 3 footprints – mentioning use of sold products downstream as particularly relevant.
- Further, the disclosure of gross emissions (scope 1-3) must exclude carbon offsets, which will be accounted for and reported on separately. This will put focus on actual downstream decarbonization of product end-use.
- **Timeline:** CSRD is currently out for consultation and expected to be ratified in June 2022. The ESRS are similarly out for consultation. Companies must submit their report aligning with CSRD on 1 January 2024, for the 2023 financial year.

Tightening national and international carbon budgets:

- There is a growing awareness that limiting global warming to 1.5 degrees will be a substantial challenge with the current rate of decarbonization, and this will be the key backdrop to intensifying efforts globally over the coming decade.
- Nationally determined contributions focus on national emissions, could it be expanded over time to also put spotlight on international emissions in the value chain?

*"The purpose of this legal framework is to create a consistent and coherent flow of sustainability information **throughout the financial value chain**"*


EUROPEAN COMMISSION

Brussels, 21.4.2021
COM(2021) 189 final
2021/0104(COD)

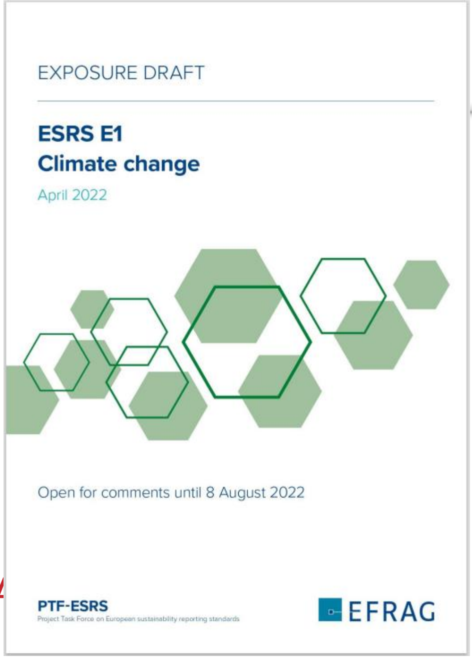
Proposal for a

DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL

amending Directive 2013/34/EU, Directive 2004/109/EC, Directive 2006/43/EC and Regulation (EU) No 537/2014, as regards corporate sustainability reporting

(Text with EEA relevance)

{SEC(2021) 164 final} - {SWD(2021) 150 final} - {SWD(2021) 151 final}



*(44) "The undertaking **shall disclose its gross indirect Scope 3 GHG emissions** in metric tons of CO2 equivalent…*

(46) *"The disclosure required by paragraph 44 shall include GHG emissions from significant Scope 3 categories and presented as a breakdown by GHG emissions from: (i) upstream purchasing, (ii)* ***downstream sold products,*** *(iii) goods transportation, (iv) travel and (v) financial investments"*

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5.1 Scope 3 considerations
Why scope 3 emissions matter for the NCS - Companies

Corporate scope 3 emissions – Increasing value and competitiveness for Norwegian oil and gas

- **Corporate value-chain emissions are international:** Most of the scope 3 emissions will be international, and strategies to reduce them may thus focus on reducing emissions occurring outside of Norway. While this will not reduce Norwegian national emissions, it can ensure continued competitiveness of oil and gas, most of which is exported and consumed abroad – and create opportunities for a Norwegian value chain, i.e. for CCS.
- **Reporting expectations increasing and to be tied to company value:** This narrative is quickly changing – as scope 3 emissions represent an outsized share of an oil & gas company's total value chain GHG footprint. As such, positively influencing emissions outside of its own direct control can thus have significant decarbonization impacts – and stakeholders ranging from NGOs to investors are increasingly expecting companies to report on scope 3 emissions, and to formulate strategies on how to reduce them. Investors are a notable scope 3 reporting adoption driver, as they increasingly want to understand the value chain carbon footprint of a company to understand where the transition risk lies – for oil & gas the bulk of this risk resides in the use of sold products (category 11). Ensuring the long-term value of Norwegian oil and gas companies will thus be likely to depend on sufficiently ambitious scope 3 emission reduction targets and the credibility of strategies.
- **Domestic scope 3 synergies can be stimulated:** Oil and gas companies operating on the NCS will also have scope 3 emissions within Norwegian boundaries and reducing these will have a direct impact on total Norwegian emissions. This can take the form of closer collaboration with Norwegian services suppliers.

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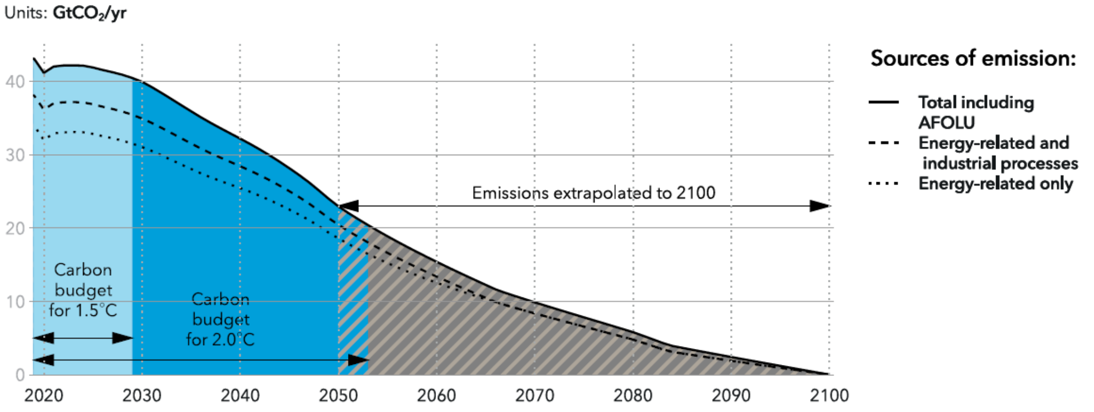
5.1 Scope 3 considerations
Why scope 3 emissions matter for the NCS - Norway

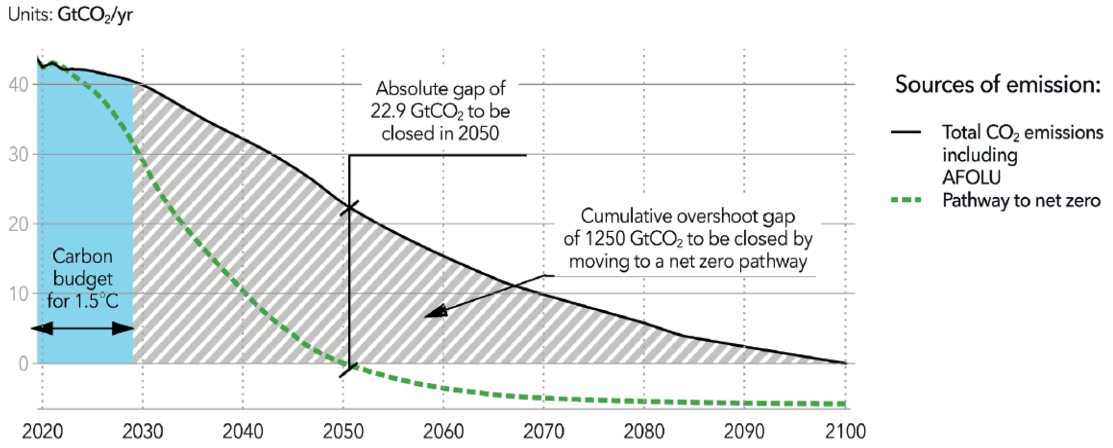
National scope 3 emissions – Delivering on national carbon budgets

- **National carbon budgets key:** At the national level, delivering GHG reductions in line with national carbon budgets is the key guiding principle for policymakers, as they have national targets and targets under nationally determined contributions (NDCs) under the Paris agreement.
- **Domestic and international emissions:** All scope 3 emissions for a Norwegian oil and gas company occurring within Norwegian national boundaries for all 15 categories go directly into a national carbon budget. This is most relevant for upstream transportation and distribution (category 4), as well as purchased goods and services (category 1) – as these will often also occur within Norwegian national boundaries. Use of sold products (category 11) and downstream transportation and distribution (category 9) mainly occur outside of national boundaries and thus do not negatively or positively impact the Norwegian carbon budget.
- **Domestic emissions likely to take precedence:** Based on this rationale, from a Norwegian government perspective, facilitating scope 3 emissions from the oil and gas sector that occur upstream and downstream and *within* Norwegian national boundaries is likely to take precedence when selecting technologies and approaches to decarbonize the NCS.
- **International emissions to come on the agenda:** A key facet of this discussion is that nation states to date has shown little appetite to take greater responsibility for scope 3 emissions from activities and products occurring outside of national boundaries. In Norway's case, national scope 3 emissions associated with the use of exported fossil feedstock and fuels are substantial. As pressures ramp up for corporates to take more value chain emissions responsibility, Norway will be pushed to take action to ensure the long-term value of its oil and gas exports.

Carbon emissions according to DNV's Energy Transition Outlook 2021



Comparing the Energy Transition Outlook and DNV's Pathway To Net Zero



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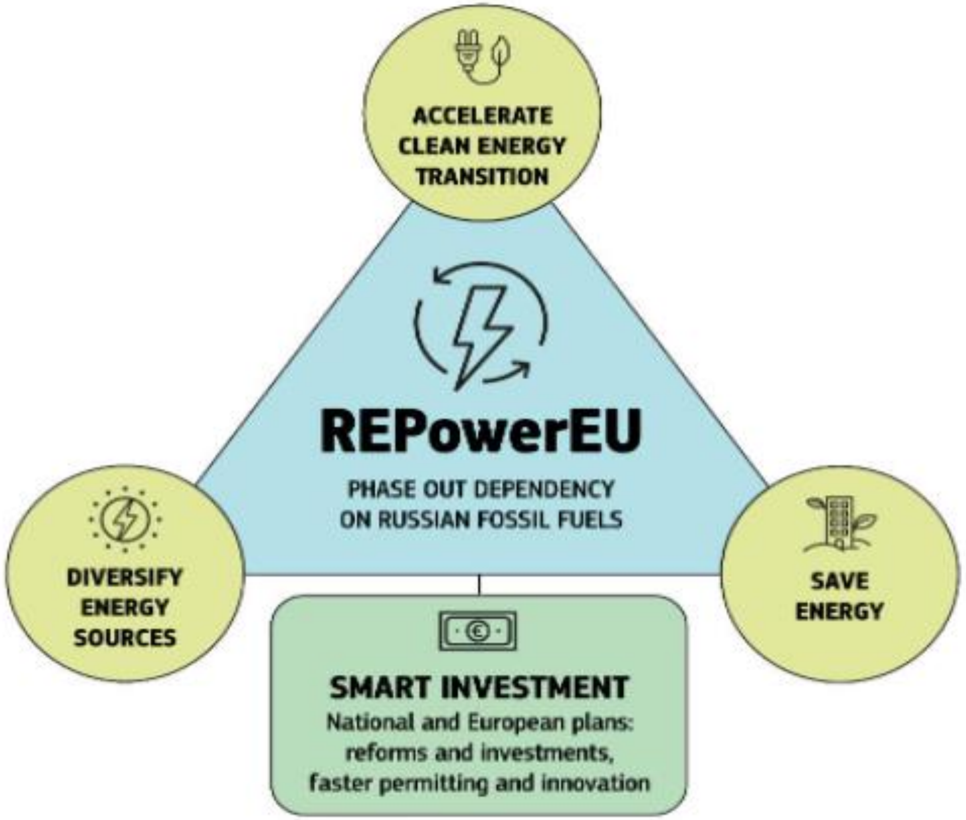
Source: DNV

5.1 Scope 3 considerations
Energy Security and scope 3 in the REPower EU Context

Reducing Russian reliance through balancing energy objectives

- **Security - Norwegian natural gas key :** As the EU diversifies gas supplies away from Russia, Norway will become the cheapest supplier through exports of piped gas. The supply security angle reduces attractiveness of shipping hydrogen (due to conversion losses and less energy being transported in pipelines).
    - **Scope 3 reduction angle:** Would be dependent on downstream natural gas decarbonisation outside of Norwegian control.
- **Efficiency - LNG cut first:** The overarching focus on reducing gas consumption will reduce gas demand over the coming decade. But as Russian gas has made up about 45% of EU natural gas imports over 2021 – there is still ample space for relatively cheaper Norwegian gas vis-a-vis LNG imports, even amid a sigifcant push for energy efficiency and natural gas consumption declines.
    - **Scope 3 reduction angle:** Would be dependent on downstream natural gas decarbonisation outside of Norwegian control.
- **Clean Energy Transition – Norway could miss the train:** Two of the three objectives actively work towards reducing gas reliance – and simultaneously building clean energy capacity. By focusing on exporting gas and not establishing local hydrogen production – Norway would be at risk over time to meet a shrinking offtake market should it take part in the energy transition.
    - **Scope 3 reduction angle:** Blue hydrogen production upstream could reduce downstream use of sold product scope 3 emissions.



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Source: European Union

5.2 Scope 3 Opportunities

Use of sold products: Natural gas power with CCS

Description

- **Natural gas-fired power with CCS:** Norwegian gas exported to the European continent can be used in industry, and notably in power generation. This could also be the case in Norway. With the application of carbon capture and storage technology, up to 90-95% of carbon emissions can be captured and sequestered in order to reduce the carbon intensity of power generated.
- **Scope 3 emission reduction:** Like blue hydrogen, natural gas power with CCS will entail some downstream use of sold products emissions – as CCS technology will not capture all emissions. A seller of natural gas will also be dependent on whether the end-consumer of the gas applies CCS technology, although this could potentially be addressed through bilateral agreements.

REPower EU Impact – Backdrop for utilisation of natural gas from NCS

- **Ultimate aim to reduce Russian gas reliance:** This will take place through efforts to reduce gas consumption and sourcing gas from other international suppliers. As the only market in Europe with significant gas production, Norway is likely to play a predominant role in helping to plug the gap from Russian gas.
- **Maximizing the effect of natural gas is another key aim:** Another energy security imperative will be to ensure that the natural gas consumed has the greatest impact in terms energy generated. As such, utilising natural gas to generate power and heat is likely to take precedence over converting it to hydrogen due to lower energy losses.
- **Reputational risk:** Over time, exporting gas – especially gas for end-use without CCS – is likely to strengthen a negative narrative of Norway exporting its emissions. This narrative could increase in propensity as corporate scope 3 emissions come more strongly onto the global climate change agenda and the discussions around the current energy crisis become more normalised.

Perspectives on Norwegian competitiveness

Pros:

- Norwegian natural gas export is key to plugging Russian supply gaps and bolstering European energy security. More expensive LNG imports will also be phased-out before Norwegian piped gas, highlighting long-term demand also in the face of long-term gas demand reductions in the EU.
- Natural gas power has a sizeable role in the EU Taxonomy, and will likely help to reduce downstream use of sold product emissions for Norwegian exported gas over time. The 100g CO2e/kWh lifecycle emission Taxonomy threshold further highlights the importance of minimising gas production and transport emissions, putting piped Norwegian gas at an advantage relative to i.e., liquified natural gas.
- Onshore gas power production with CCS could resolve electricity generation capacity limitations for the NCS and enable more electrification and thus decarbonise more oil and gas assets.
- A pipeline of CCS projects can also establish Norwegian technological expertise that can be exported. This could in turn enable Norway to capitalise on international opportunities, as well as to showcase a greater commitment to taking responsibility for downstream emissions.
- Gas power with CCS can facilitate substantial scope 3 emissions reductions, and developing greenfield natural gas capacity with CCS in Norway may be easier than retrofitting existing gas power capacity in Europe.

Cons:

- Risk of limited involvement of Norwegian companies in establishing CCS technology in Europe.
- Over time, use of sold products emissions downstream can create reputational risk associated with gas exports and put spotlight on Norway exporting emissions.

Downstream natural gas w/CCS with the CO2 shipped to Norway – a potential opportunity?

- **CCS as a Norwegian service (for continental Europe or locally):** According to the NPD's CO2 atlas, it is possible to store up to 80bn tonnes of CO2 on the NCS. There could be long-term scope for shipping such emissions for storage in Norway. Note that this also applies for blue hydrogen production in Norway.
- **COP26 Article 6 and related opportunities:** The finalization of article 6 on carbon trading, and notably 6.2 on bilateral actions could create new opportunities Norwegian carbon storage. Notably, Norway could in theory be able to deduct emissions captured internationally but stored in Norway from the Norwegian carbon budget – if in ownership of the carbon stored, enabled by the contract structure. However, the details on this remain uncertain, notably on the liability of storage leaks. It could also be argued that Norway would be importing more emissions in this case, and a more likely outcome is thus that Norway stores CO2 on behalf of other markets.

5.2 Scope 3 opportunities

Use of sold products: Blue hydrogen production and hydrogen derivatives

Description

- **Natural Gas methane reforming with CCS:** A large share of conventional grey hydrogen is produced with natural gas methane reforming. A by-product of the process is carbon emissions, which in the case of blue hydrogen would be captured at the point of production and stored. The hydrogen would be sold as either hydrogen or as feedstock for further conversion into for example blue ammonia.
- **Scope 3 emission reductions:** By capturing and storing (most of) the emissions associated with methane reforming, the emissions associated with the downstream use of sold products would be substantially reduced – in turn reducing value chain emissions. For hydrogen-consuming companies reporting their upstream scope 3 footprints, blue hydrogen would be favourable to grey hydrogen and could fetch a premium. For a blue hydrogen producer, the downstream scope 3 footprint would be reduced, reducing climate transition risk and bolstering sustainability credentials.

REPower EU Impact on blue hydrogen opportunities

- **Higher gas prices:** Rising gas prices, exacerbated by the Russian invasion of Ukraine, could shift the narrative that blue hydrogen is a transition fuel on the way to green hydrogen and derivatives.
- **Energy security considerations:** Converting natural gas to hydrogen entails high energy conversion losses, and with energy security being the core focus of REPower EU, using the natural gas for heating/cooking, power generation and industry is likely to be a more favourable option. As Europe is in direct need of gas to replace the phase-out of Russian gas, it is unlikely that significant amounts of surplus natural gas will be available for producing blue hydrogen.
- **Impact of weaning off Russian Gas:** Norway will have an outsized role in supplying Europe with gas, as such, it may be better to let the downstream market decide how to best utilise the gas. This would, however, give Norway little impact on scope 3 emissions from use of sold products.
- **Rising need for European ammonia:** Ammonia is typically produced with grey hydrogen from methane reforming, applying CCS to reduce emissions is likely to be expected over time. Ammonia is also favourable to store and transport at scale compared to hydrogen. A global market for ammonia as a fuel is expected to become large, and an early start for offshore ammonia is key.

Perspectives on Norwegian competitiveness

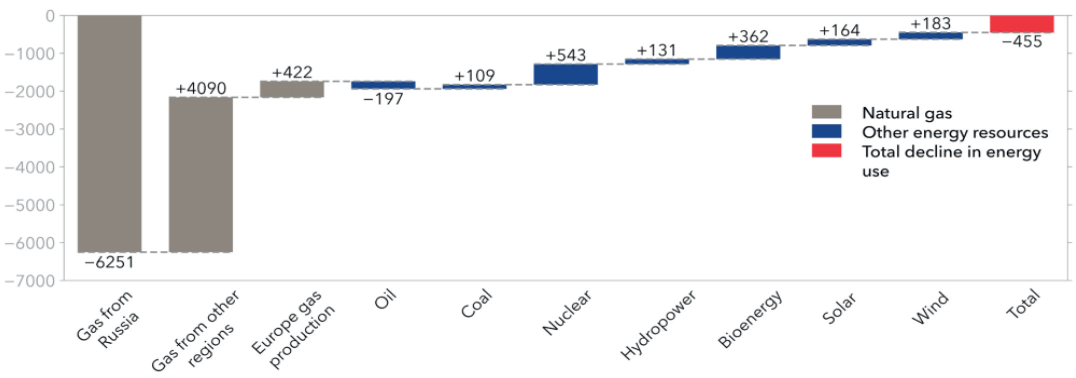
Pros:

- Blue hydrogen consumed downstream leads to substantial reduction in use of sold products emissions.
- Investing in blue hydrogen capacity better positions Norway for capitalising on the hydrogen economy.
- Rising demand for European ammonia, which today is almost exclusively grey. Applying CCS to existing grey ammonia production will be key to reducing fertiliser manufacturing GHG emissions and driving consumption as a low-carbon fuel.
- CCS in Norway with storing CO2 locally can be easier than in Europe due to more experience.

Cons:

- High gas prices reduces cost competitiveness and highlights a tight gas market, likely for a limited time
- Unlikely that there will be any surpluses of Norwegian gas in line with the anticipated reduction in Russian gas. The chart below illustrates a DNV scenario for how other sources of natural gas or alternative energy replace Russian gas – of which relatively expensive LNG is essential to topping up Norwegian gas. Piped gas is more cost-competitive, highlighting a long-term market for Norwegian gas.
- High gas-to-hydrogen energy conversion cost are misaligned with EU energy security imperatives.
- New pipelines that can take large volumes of hydrogen would be needed, which take years to materialize. Lower energy content of hydrogen (30% of energy content of methane) requires more pipeline capacity for same energy content shipped.
- CCS scaling benefits can be more cost-competitively derived from sectors covered by the EU ETS, with grey ammonia currently receiving free allowances due to carbon leakage risk.

Impact of Ukraine war on European primary energy mix in 2024, compared to pre-war ETO* model run



*ETO = DNV Energy Transition Outlook, Source: DNV

5.2 Scope 3 opportunities

Capitalising on transition: Production and export of green/blue hydrogen/ammonia

Description

- **Energy production:** The main bottlenecks for a fast energytransition are to make enough emission free energy and to change consumers. To reach the 1.5 degree target, energy mix in Europe need to be 50% electricity, 30% hydrogen and 20% gas (PNZ*) in 2050. A massive industrial development is needed and it is only possible if by using the available technologies. This is wind and solar power, and for Norway's part, it is offshore wind that is most effective. Offshore wind can also provide local electricity to gas production. In the ETO**, it is also found that blue hydrogen would be more cost competitive than green until green hydrogen cost is scaling and dropping.
- **Energy transport:** As the need for renewables increases, the distance from populated areas in Europe to sun and wind farms will increase. At some distance and volume, the cost of energy transport will be lower with pipelines than cables. Massive export of energy from Norway is likely to be more effective with pipelines than with cables. Ammonia transport with pipelines and ship is also more effective and mature than hydrogen.
- **Strategy:** A massive switch of all new investments from oil and gas to produce green electricity, and blue and green hydrogen and ammonia; first onshore and then offshore. Use on Norwegian market consumers and for massive export when volumes ramps up.
- **Reputational risk:** Will be applauded by all, not only in Europe but globally.

REPower EU Impact

- **May 18th the REPower EU** released a plan to import (10 mill tonnes) hydrogen from near by areas where the North Sea is one of the main hydrogen corridors that are supported, see figure. A massive infrastructure to use hydrogen including storage and pipeline transport is also supported (EUR 50 billion) [COM_2022_230_1_EN_ACT_part1_v5.pdf (europa.eu)]
- Strategy is to quickly substitute fossil by accelerating clean energy, and diversify supplies
- To use this opportunity when more energy is needed to accelerate renewables

Perspectives on Norwegian competitiveness

Pros:

- Secure Norwegian and European clean energy for next generations (reducing scope 1, 2 and 3)
- Accelerate the energy transition and have a chance to meet the Paris goal of 1.5 degrees
- Secure Norwegian oil and gas and industry companies and workers through the transition by spearheading new industry development
- Exporting technology globally is a growth area for Norway
- The changes are relatively small for O&G companies and they have a large competitive advantage.
- When renewable energy infrastructure is developed, it will remain relevant and does not face the same stranded asset risk like O&G infrastructure. Initially expensive infrastructure can eventually be profitable.
- Hidden cost of climate transition risk is eventually reduced, supporting Norwegian companies.
- Norway is a stable and reliable country that can facilitate long-term industrial development.

Cons:

- Massive investments are needed in capex and technology and infrastructure developments. These costs will however not exceed hidden the costs of climate change tipping points, which could be sudden.
- Regulations, codes and standards needed. Safety is a bottleneck for hydrogen and ammonia.
- More training and competence building needed
- Biodiversity and the natural world will be more disturbed by massive wind farms and new infrastructure.
- Other regions like Mediterranean and East Europe may offer competition

Opportunity with stranded off-grid renewables

- **The world has plenty of attractive "off-grid" areas for wind and solar.** An opportunity is to develop a wind farm with local off-grid ammonia production that can easily be transported by a carrier. The ammonia FPSO can use electrolysis and Haber Bosch process to make hydrogen and ammonia offshore. A loading to a ammonia carrier can be developed for global export. A market for this concept can be tested in Norway and then used globally when standardized. The amount of energy that can be harvested is almost limitless and the cost of such units can be reduced when scaling.
- **A large number of innovations are likely to come with investment**
- **Time is now.** The wind turbine industry sees currently a massive growth. E.g. lead time for a new wind turbine is now 4 years. This is expected to increase, hence by waiting it will be even slower and Norway can fall behind in this technology development.

*PNZ = Pathway to Net Zero, report in the **Energy Transition Outlook (ETO) series, DNV

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5.3 Comparing opportunities

High	Medium	Low

A top-level assessment of scope 3 emission reduction options

	Base case: Gas power without CCS in Europe	Gas power w CCS in Norway	Gas power w CCS in Europe	Blue hydrogen and derivatives in Norway
Scope 3 reduction potential - company-level	• No scope 3 reduction	• Potential large scope 3 emissions reductions depending on supply chain ownership structure.	• Scope 3 emissions reductions depending on supply chain ownership structure, but less likely as gas goes into existing gas infrastructure with limited CCS integrated.	• Potential large scope 3 emissions reductions depending on supply chain ownership structure.
National control over Scope 3 reduction	• No scope 3 reduction	• Norway can document it takes control over own use of sold product emissions	• Potential control if contributing to CCS value chain as well as contracts	• Norway can document it takes control over own use of sold product emissions.
Contributing to reaching national emission targets	• No contribution	• Potential for electrification of industry and NCS	• No contribution	• Potential for decarbonising national hard-to-abate sectors, but dependent on technological development up to 2030.
Synergies with Scope 1 reduction on the NCS	• No contribution	• Potential for significant scope 1 emissions reductions by increasing onshore electricity generation capacity	• No synergies	• Developing a value chain that over time can facilitate significant scope 1 long-term emissions reductions
Contribution to the total energy system	• Helping to reduce overall global emissions by replacing coal power. • Balancing an energy system with large amount of variable renewables, but with significant emissions.	• Electricity source for NCS and addressing push-back against oil and gas absorbing electricity that would otherwise go to other forms of electricity consumption. Less essential for energy system balancing.	• Balancing an energy system with large amount of variable renewables. • Helping to reduce overall global emissions by replacing coal power.	• Potential for providing flexibility to the energy system, both for power production as well as seasonal storage

5.3 Comparing opportunities

A top-level assessment of scope 3 emission reduction options

High	Medium	Low

	Base case: Gas power without CCS in Europe	Gas power w CCS in Norway	Gas power w CCS in Europe	Blue hydrogen and derivatives in Norway
Industrial development in Norway	• Gas industry already well-established	• Creation of CCS value chain and expertise • New jobs	• Less involvement of Norwegian companies is likely – potential scope for CCS technology exports and carbon imports	• Creation of CCS value chain and expertise • Creation of hydrogen value chain and market that can facilitate green hydrogen uptake long-term • New jobs
Energy loss	• Gas power generation, assuming CCGT (~40% losses) • Low losses in energy transmission (2-5%)	• Gas power generation, assuming CCGT (~40% losses) • CCS value chain adds some losses (~10-15%) • Low losses in energy transmission (2-5%)	• Gas power generation, assuming CCGT (~40% losses) • CCS value chain adds some losses (~10-15%) • Low losses in energy transmission (2-5%)	• Conversion losses from gas to hydrogen with CCS (~30-65% losses, depending on end-state) • Potential additional losses if hydrogen is used for power generation (~40-70% losses) • Less efficient energy transmission (30% energy content compared to methane)
Revenue creation pre-2030	• High from exports of gas	• Potential for selling power, but less revenue from gas exports	• High from exports of gas	• Uncertain market towards 2030
Revenue creation post-2030	• Less certain as gas demand might fall over time, uncertain gas prices	• More stable revenue from power sales	• Less certain as gas demand might fall over time, uncertain gas prices	• Likely an established market for hydrogen, but uncertain market situation for fossil hydrogen.

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