WHEN TRUST MATTERS

Low-emission technologies to decarbonise the Norwegian petroleum value chain

September 2022

OG21 deep dive study

Important Notice and Disclaimer

1. This document is intended for the sole use of the Customer as detailed on the next page of this document to whom the document is addressed and who has entered into a written agreement with the DNV entity issuing this document (“DNV”). To the extent permitted by law, neither DNV nor any group company (the "Group") assumes any responsibility whether in contract, tort including without limitation negligence, or otherwise howsoever, to third parties (being persons other than the Customer), and no company in the Group other than DNV shall be liable for any loss or damage whatsoever suffered by virtue of any act, omission or default (whether arising by negligence or otherwise) by DNV, the Group or any of its or their servants, subcontractors or agents. This document must be read in its entirety and is subject to any assumptions and qualifications expressed therein as well as in any other relevant communications in connection with it. This document may contain detailed technical data which is intended for use only by persons possessing requisite expertise in its subject matter.

2. This document is protected by copyright and may only be reproduced and circulated in accordance with the Document Classification and associated conditions stipulated or referred to in this document and/or in DNV’s written agreement with the Customer. No part of this document may be disclosed in any public offering memorandum, prospectus or stock exchange listing, circular or announcement without the express and prior written consent of DNV. A Document Classification permitting the Customer to redistribute this document shall not thereby imply that DNV has any liability to any recipient other than the Customer.

3. This document has been produced from information relating to dates and periods referred to in this document. This document does not imply that any information is not subject to change. Except and to the extent that checking or verification of information or data is expressly agreed within the written scope of its services, DNV shall not be responsible in any way in connection with erroneous information or data provided to it by the Customer or any third party, or for the effects of any such erroneous information or data whether or not contained or referred to in this document.

4. Any estimates or predictions are subject to factors not all of which are within the scope of the probability and uncertainties contained or referred to in this document and nothing in this document guarantees any particular performance or output.

Report details

Project name	Low-emission technologies to decarbonise the Norwegian petroleum value chain	DNV AS Veritasveien 1 1363 Høvik Norway Tel: +47 67 57 99 00 http://www.dnv.com
For	OG21	
Client reference	Gunnar Hjelmtveit Lille	

Date of issue	30.09.2022	Project number	-
Report number	2022-0939	Organizational unit	Energy Systems
Contract number		Subject group	Energy Markets & Strategy

Prepared by	Frida Berglund, Daniel Brenden, Ole Kristian Sollie, Erik Andreas Hektor, Yongtao Yang, Frida Mattson, Elisabeth Rose, Jørgen Bjørndalen, Kjersti Aarrestad, Marcel Cremers, Bart in 't Groen, Koen Hellebrand, Elizabeth Mackie	Contact name	Frida Berglund
Verified by	Torild R. Nissen-Lie	Contact email	-
Approved by	Sture Olav Angelsen	Contact phone	-

X	Open	Key words	decarbonisation, energy transition, oil and gas
	Internal use only		
	Commercial in confidence		
	Confidential	Service Area	
	Secret	Market Segment	

Reference to any part of this report which may lead to misinterpretation is not permissible.

Table of contents

Executive summary

Identifying and prioritising measures for Norwegian O&G decarbonisation

- **The pressure is increasing on accelerating decarbonisation:** There is a rising emphasis on intensifying decarbonisation efforts in order to mitigate increasingly evident global warming impacts and meet looming 2030 targets to reduce emissions aligned with national, regional and Paris commitments. For Norway, in the near-term this entails reducing greenhouse gas (GHG) emissions by at least 50 percent and towards 55 percent by 2030 compared to 1990 levels – and in the long-term to be a low emission society by 2050. As of end-2021, Norway had only reduced emissions by 4.5 percent compared to 1990 levels. Comprising the highest share of Norwegian emissions (around 25 percent), the Norwegian oil and gas (O&G) industry has a responsibility in enabling Norway to meet its decarbonisation targets. As part of the temporary changes to the Petroleum Tax Act in 2020, the Parliament set an absolute target of 50 percent scope 1 emission reductions by 2030 compared to 2005 levels for the industry. This is also the target now adopted by KonKraft when assessing the status of the climate strategy (previous target of 40 percent reduction by 2030).

- **Traditional measures for decarbonising O&G assets are heavily debated:** Electrification through power from shore is viewed as the main measure to decarbonise the Norwegian O&G industry. However recent developments have sparked a heated debate on how the power grid should be developed and whether O&G assets should be electrified from shore. Other decarbonisation measures are under development, however current maturity, plans and adoption pace do not suggest sufficient scale by 2030. There is a need to investigate whether further measures can be taken to accelerate technology development and implementation in the coming years.

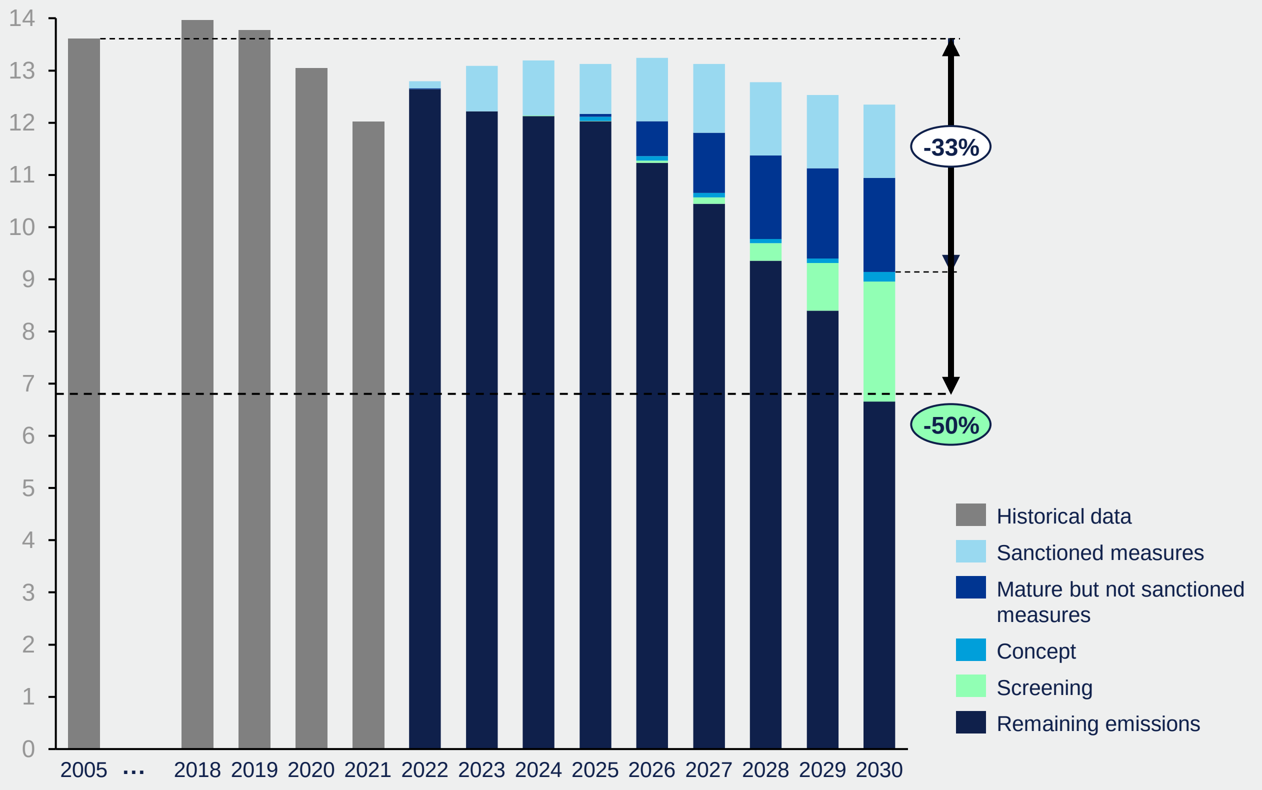
- **Need for assessing various decarbonisation measures and ways of accelerating implementation:** Through this study, Oil and Gas for the 21st Century – “OG21” – has commissioned DNV to describe realistic ways to accelerate the technology implementation required to meet the GHG emission reduction targets, as well as how Norway can take a leading role in emerging industries and petroleum decarbonisation by ensuring Norway’s leading energy companies and their suppliers provide a competitive edge. Moreover, there is increasing focus on decarbonising the whole petroleum value chain, and DNV has therefore also investigated opportunities for the Norwegian O&G industry in taking responsibility for reducing scope 3 emissions.

Decarbonisation measures can increase competitiveness but more is needed to meet the targets

- **Norwegian gas demand stronger for longer:** It is uncertain to what extent oil and gas demand will fall leading up to 2050. From a Norwegian perspective, European demand for natural gas is set to be more robust in the near-term, given EU aims to rid itself of Russian gas by 2027. Piped Norwegian gas will be cheaper and with a lower GHG footprint for the EU than imported LNG, helping to ensure a European market for Norwegian natural gas.
- **Pace of EU gas demand contraction still a key question-mark:** On the other hand, EU's aim to significantly cut gas demand could also eat into Norwegian exports over time which poses a risk in the longer term. By committing to further reductions in GHG emissions through decarbonisation measures discussed in this report, the competitiveness of piped gas from Norway can be strengthened compared to alternatives and thereby be the last to be phased out towards EU's pathway to net zero.
- **More measures needed:** KonKraft estimates that an emission reduction of 33 percent is possible by 2030, compared to 2005 levels, when looking at sanctioned measures as well as measures that are relatively mature. Through adding measures currently in the concept/screening phase, a 51 percent GHG reduction is projected. As it is unlikely that all immature measures will be implemented, developing additional prospective measures is essential to delivering a 50 percent reduction by 2030. Moreover, having a suite of measures that take the potential reductions beyond 50 percent is essential in order to offset the risk that certain measures are not implemented.
- **GHG reduction measures must focus on gas turbines and big emitters:** With gas turbines making up 83 percent of scope 1 emissions, and eight O&G installations making up over 50 percent of total emissions on the Norwegian Continental Shelf (NCS), measures should target emission stemming from gas turbines and largest emitters to deliver on the GHG emission reduction commitments.

Historical and forecasted emissions on the NCS and onshore facilities

[million tonnes CO_2eq/yr]



Source: KonKraft (2022)

DNV

Prioritising decarbonisation measures to steer focus

From long-list to short-list

DNV has identified and assessed a **long-list of measures** that can support the NCS in meeting near- and long-term GHG emission reduction targets. The assessment has been undertaken through an iterative process whereby DNV experts have evaluated the various technologies across a set of screening criteria, with opinions having been informed and qualified through input provided by OG21 experts in workshops with all five OG21 Technology Groups (TGs). All measures have been scored by applying a “high”, “medium” or “low” traffic light methodology across the set of criteria, with the aim to take a holistic view on the overarching potential of each measure as well as to specifically identify and visualise potential barriers and opportunities.

On the basis of the input from the workshops as well as the scoring assessment, the measures listed in the long-list were narrowed down to a **short-list of measures.** These measures have received the main focus of this study, as the ones with the biggest potential to help accelerate decarbonisation on the NCS. However, it is important to note that although some technologies are not part of the short-listed measures, this does not mean that DNV does not see a potential for scaling these technologies offshore.

Long-list of decarbonisation measures

Replacing gas turbines through electrification

- Electrification: Power from shore (coordinated approach)
- Electrification: Power from shore (individual approach)
- Electrification: Local supply from offshore wind
- Gas-fired power hub with CCS

Reducing emissions from the gas turbines

- Compact topside CCS
- Hydrogen and hydrogen-derived fuels for power production
- Optimized gas turbines: Utilisation

Increasing the energy efficiency

- Energy efficiency through reservoir management: Water management
- Energy efficiency through reservoir management: Artificial intelligence
- Energy efficiency through reservoir management: CO_2-EOR
- Optimized gas turbines: Waste heat recovery
- Geothermal energy to reduce electrical power demand offshore

Short-listed measures to accelerate decarbonisation

- **Electrification: Power from shore (coordinated approach)**
- **Electrification: Power from shore (individual approach)**
- **Electrification: Local supply from offshore wind**
- **Gas-fired power hub with CCS**
- **Energy efficiency through reservoir management: Water management**

Electrification

Key takeaways

Power from shore (coordinated and individual approach)

- Electrification of O&G platforms through power from shore is considered a key measure to achieving the GHG emissions reduction targets, with an estimated total potential of 4.5 million tonnes CO_2e emission reduction per year in 2030. The preferred network design solution depends on several factors, and two fundamentally different options exist: an individual and a coordinated design approach.
- **Individual design approach**: Each platform is connected to the onshore grid via a dedicated radial connection. This design offers simplicity and requires less coordination but can result in an overall sub-optimal network design and higher costs to ensure reliability of supply.
- **Coordinated design approach**: Multiple platforms are connected to one offshore hub (shared substation) before being further connected to the onshore grid through a radial connection. Although this is a more complex design requiring a high degree of coordination between stakeholders with different ownerships in licenses and assets, significant economics of scale and a more optimal network design can be achieved.
- The main obstacles are related to distances from shore and weight and space limitations for DC equipment, high cost and potential loss of revenue due to downtime during retrofitting, access to sufficient power from shore, as well as long lead times. For a coordinated approach, differences in remaining lifetime of assets and frequency levels are also important challenges.
- Several mitigations exist on technical obstacles such as subsea or more compact equipment. On more political and societal obstacles, important mitigations include speeding up decision-making processes, establishing predictable policies and frameworks to give clear investment signals for offshore electrification, and building out new renewables and grid capacity.
- Although electrification of platforms through power from shore is considered a key measure, anticipated reduction in power surplus and increased grid constraints, historically high power prices and continued domestic bidding zone price gaps, in additional to a challenging geopolitical landscape has caused a heated political debate on how the power grid should be developed and whether the NCS should be electrified from shore. This brings uncertainty to developers and operators. Long-term and predictable policies are crucial in reducing risks.

Local supply from offshore wind

- Norway has excellent offshore wind resources and should act on the opportunity to take part in the global megatrend of offshore wind development.
- O&G platforms could be supplied with electricity from offshore wind turbines without a connection to shore. As such, this solution can help provide electrical power to installations in areas with long distances to shore or where the onshore grid is constrained. However, this would require a back-up solution to ensure consistent power supply.
- Offshore wind can be either bottom fixed or floating, however the water depth on the NCS suggests floating solutions are largely required. Floating wind is approaching large scale and commerciality, with only a few years before we will see the large multi unit-projects. Innovation and developments are still needed in order to reduce costs.
- According to KonKraft, electrification through local supply from offshore wind is estimated to have a potential of 0.4 million tonnes of CO_2e emission reductions per year in 2030 (based on reported measures). However, the potential can be much higher, especially in areas where electrification from shore is challenging. Installing a wind farm could also be an intermediate solutions until a cable from shore is in place.
- Supply chain constraints, long lead times and insufficient policies are key obstacles for implementing offshore wind. In order to ensure predictability, it is important to speed up decision-making processes, develop local supply chains, ensure sufficient support mechanisms and coordinate developments across industries.
- Combining power from shore with offshore wind can ensure security of supply as well as power supplied to shore during surplus hours. Technically, the power cable should be able to export back to the shore without major adjustment.

Key advantages and opportunities

- Electrification increases the energy efficiency, resulting in less energy use overall. Moreover, the operational costs can be reduced due to lower cost of CO_2 tax and fuel. Electrification of offshore assets will also have the indirect benefit of reduced noise and thereby improved working environment offshore.
- The released natural gas can be exported to Europe and used in onshore gas power plants with higher efficiencies. This will both increase export revenues for Norway while at the same time helping Europe to become independent of Russian gas.
- A combination of building out an offshore grid with power form shore and offshore wind farms to supply installations on the NCS has several industrial opportunities: developing floating offshore wind industry in Norway; ensuring security of supply to the installations and power supply to the onshore grid during surplus hours; facilitate a future meshed offshore grid that can connect to the planned North Sea offshore grid long-term; facilitate an offshore industry long-term when O&G assets are decommissioned.
- Concepts of combining offshore wind with existing power-from-shore concepts, e.g. Utsira High or Troll West, can be especially relevant, as investments in transmission supply are already paid for. This can reduce OPEX from power purchases, limit total power losses through the transmission cables, while also give rise to fast-track medium-sized wind farms that could be important stepping stones to cost-efficient large-scale wind farms in the early 2030's. An important obstacle that should be further investigated is the uncertainty in regulatory frameworks for delivering power to shore under the Petroleum Tax Act.

Gas-fired power hub with CCS
Key takeaways

Gas-fired power hub with CCS

- A gas-fired power plant with CCS provides electricity through running gas turbines while capturing and storing the CO_2. The plant could be located both onshore or offshore, and the preferred solution will depend on several factors (costs, available infrastructure, permits and regulation, political and societal acceptance, amongst others) which will depend on the given case.
- Several concepts have been developed, but none has been constructed to date. Use of qualified equipment as far as possible will be important in order to reduce risk and uncertainty.
- An offshore power hub is a stand-alone solution independent of power from shore. As such, it can help provide electrical power to installations in areas with limited onshore infrastructure or long distances to shore. In the long term, the power hub could be connected to shore to supply additional power and balancing capabilities to the onshore grid. An onshore gas-fired power plant is in principle the same concept as power from shore but could help increase power production onshore.
- DNV's analysis show that offshore power hubs located in three areas could reduce emissions by 4.5 million tonnes CO_2e per year in 2030 (around 35 percent total reduction from 2020 levels), if all required infrastructure for transport and storage of CO_2 is in place.
- A power hub requires many operators and stakeholders to agree on a solution and distribute cost and risk, so early dialogue and cooperation is key for getting this measure started.
- The solution could help further develop the Norwegian CCS supply chain, cementing Norway as a global leader in CCS activities and commercial CCS value chains.

Photo: DNV/DGS AS

Reservoir water management
Key takeaways

Energy efficiency through reservoir water management

- With increasing energy cost and CO_2 price, the incentive for promoting new and improved technologies will increase. Co-operation between operators, vendors and expert areas is key to promote technology developments and remove silos.
- The potential for energy optimization for water management stems from topside with optimal use of water pumps and compressors, subsea or downhole water treatment with separation and reinjection of water, and control of well inflow by smart completion. Choice of solution and resulting GHG emission potential is highly case sensitive, and the key to success for water management will be good reservoir understanding in combination with efficient use of data and technology.
- The costs of new water displacement technologies are high. Standardization of technologies will bring down costs and risks, as will strengthening regulatory requirements to apply new technology in license and PDO-processes.
- Several possibilities are available to limit water inflow and the energy used for water management.
- Tail-end production with high water-cut wells is energy intensive. For the fields with the highest water-cut, shut-down of the fields might be a more economically viable solution taking a long term industry perspective. If the industry is not progressing to meet GHG emission reduction targets, the government could respond by increasing the CO_2 taxes and thereby reduce the long term value of all O&G industry production.

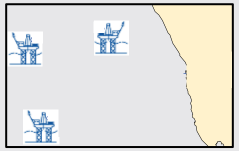
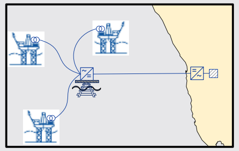
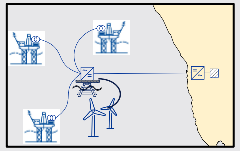
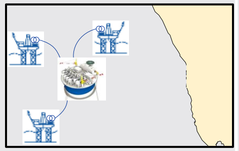
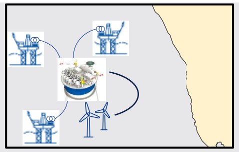
Case study on selected measures
Main results

A high-level case study on a full electrification of three platforms with 85 MW power demand each located close to each other was performed, comparing a few selected measures. The following results can be observed:

- **The most expensive option measured in LCOE is not doing anything** (Case 0). This is due to the high CO_2 tax and fuel cost (the alternative value of exporting natural gas).
- All alternative cases will result in energy being used more efficiently, with the power from shore cases being the most energy efficient, as well as more gas being available for export to Europe.
- **Case 1 (Power from shore through a coordinated approach) has the lowest LCOE and abatement cost** due to lower investment costs compared to the alternatives. However, it must be noted that this does not include investment costs for upgrading the grid capacity onshore, which might be needed depending on the location of the platforms.
- Case 2 (Gas-fired power hub offshore with CCS) has a higher LCOE than power from shore, however is a **stand-alone solution and thus not dependent on the onshore grid**. Note that a case with gas-fired power hub onshore with CCS has not been assessed in this case study, as the concept is similar to electrification through power from shore.
- **Introducing floating offshore wind helps reduce the OPEX** as it either reduces the cost of purchasing electricity (Case 1.1.) or reduces the cost of fuel and CO_2 tax (Case 2.2). However, the LCOE and abatement cost is increased due to higher investment costs.
- All cases have an abatement cost exceeding the expected CO_2 price in 2030. However, it is not unreasonable to expect a further increase in the CO_2 tax beyond 2000 NOK/tonne CO_2.
- It is important to note that this case study is **high-level** and that the cost of various measures are **extremely case dependent.** Moreover, potential project specific cost factors have been excluded, such as downtime for retrofitting and associated postponed revenue*. The following slide present **sensitivity analysis** to show how the results are affected by a change in the assumptions.

Results using the base case assumptions. Sensitivity analysis on key parameters are presented in the following slide

Key assumptions are presented in Section 4. Both the LCOE and abatement cost are calculated based on discounted flows (costs, energy and CO_2)

	0: Do nothing	1: Power from shore (coordinated approach)	1.1: Floating wind turbines and power from shore	2. Gas-fired power hub offshore with CCS	2.1: Floating wind turbines and gas-fired power hub offshore with CCS
Conceptual illustration					
Short description	Running traditional gas-fired turbines without modifications.	250 MW HVDC cable from shore with dedicated jacket for DC equipment, AC supply to platforms.	Same as case 1 including floating wind turbines with installed capacity of 85 MW.	Sevan floater 250 MW power hub as stand-alone solution located with AC supply to platforms.	Same as case 2 including floating wind turbines with installed capacity of 85 MW.
Power purchased from shore [TWh/yr]	-	1.10	0.75	-	-
Power produced offshore [TWh/yr]	1.10	-	0.35	1.10	1.10
Fuel consumption [TWh/yr]	3.65	-	-	2.00	1.40
CO_2 emitted [tonne/yr]	722,700	-	-	39,400	27,100
CAPEX [MNOK]	N/A	12,780	15,580	16,760	19,560
O&M costs [MNOK/yr]	80	120	155	80	110
CO_2 tax [MNOK/yr]	1,455	-	0	80	55
Fuel/electricity cost [MNOK/yr]	790	580	400	430	300
Abatement cost [NOK/ tonne CO_2 abated]	**N/A**	**2,680**	**2,786**	**3,271**	**3,326**
LCOE [NOK/kWh]	**2.41**	**1.77**	**1.84**	**2.04**	**2.11**

*The required downtime for retrofitting is highly project specific. Electrification of assets can be completed within normal maintenance stops, depending on the technical basis and careful planning. In other cases, additional downtime will be required.

Case study on selected measures

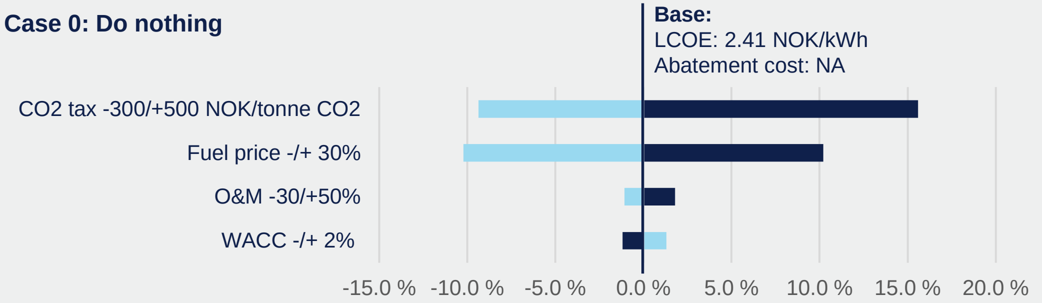
Sensitivity analysis

Sensitivity analysis have been performed to assess the uncertainty in the results as well as map out which parameters have the highest effect on the results. As no uncertainty has been applied to the power production or the CO_2 abated, the results shown below (percentage change) apply to both the LCOE and the abatement cost.

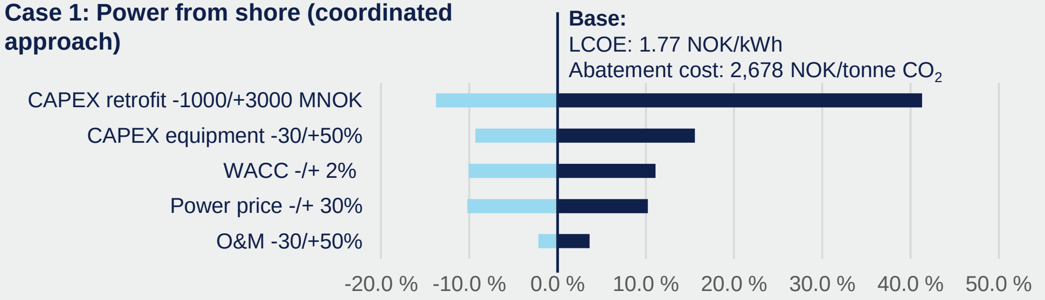
The analysis show that the CAPEX for retrofitting of the platforms have the highest impact (positive and negative) for most cases. This is due to the fact that the cost of retrofitting is extremely case dependent and as such the uncertainty ranges are high.

Even with a low retrofitting cost, the abatement cost is higher than the CO_2 price for all cases. Although not assessed here, the abatement cost could be lower than the CO_2 price in the event of several assumptions being reduced simultaneously (e.g. both a lower CAPEX of retrofitting and a lower CAPEX on equipment). Moreover, it is not unreasonable to expect a further increase in the CO_2 tax beyond 2000 NOK/tonne CO_2. For business as usual (the "do nothing" case), the CO_2 tax and fuel price have the highest impact on the results. Further details can be found in Section 4.

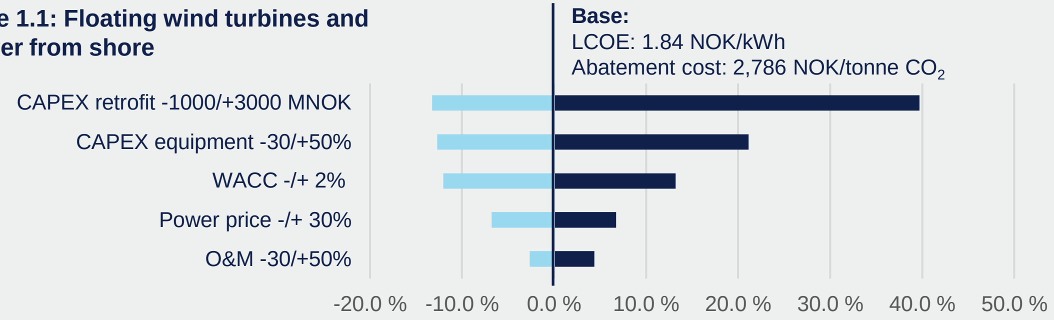
Case 0: Do nothing



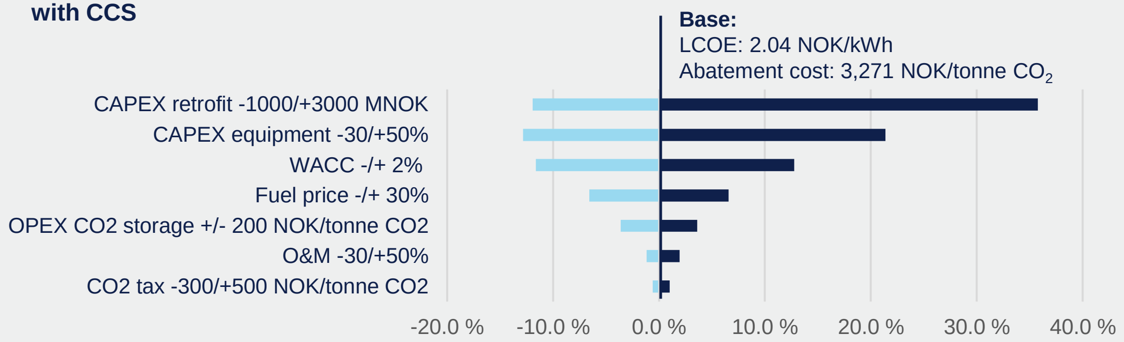
Case 1: Power from shore (coordinated approach)



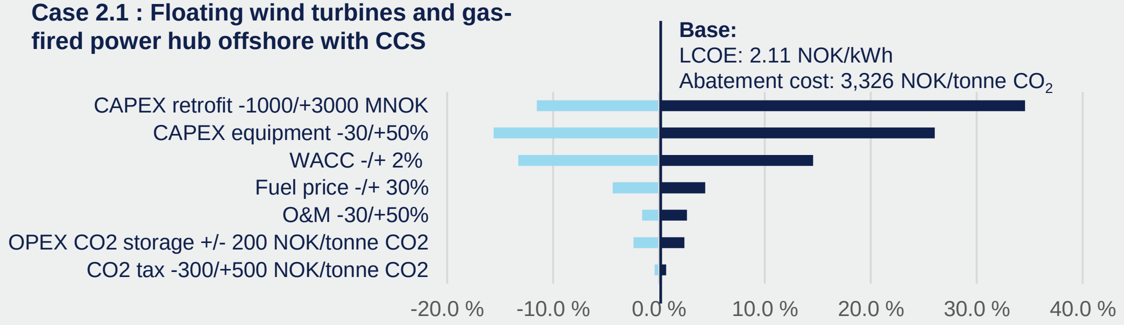
Case 1.1: Floating wind turbines and power from shore



Case 2: Gas-fired power hub offshore with CCS



Case 2.1 : Floating wind turbines and gas-fired power hub offshore with CCS



Scope 3 emission reductions increasingly important, with large value potential for Norwegian O&G industry

- **Scope 3 reporting pressures ramping up:** Oil and gas companies increasingly are expected to report on scope 3 emissions and include them in decarbonisation targets, to capture full 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", according to the GHG Protocol. The EU Corporate Sustainability Reporting Directive will require reporting and tracking of scope 3 emissions, while stakeholders ranging from investors to NGOs expect companies to report on scope 3 emissions and develop strategies on how to reduce them.
- **Safeguarding value and competitiveness:** Devising ways to reduce scope 3 emissions for Norwegian O&G companies will become a key to the long-term competitiveness and value of the sector. Scope 3 emissions can be reduced by i.e., setting supplier requirements, decarbonising fuels upstream or downstream decarbonisation (i.e., converting natural gas to blue hydrogen or generating natural gas-fired power with CCS). Ensuring the long-term value of Norwegian O&G companies will thus likely depend on sufficiently ambitious scope 3 emission reduction targets and the credibility of strategies.
- **Tackling use of sold products emissions is key to reducing scope 3 footprint:** Around 75% of scope 3 emissions from the O&G sector stem from emissions from the use of sold products (category 11 in the GHG Protocol). This is also where investors assess the main transition risk of their oil and gas company exposure to lie, and as they look to reduce such risks, working with the decarbonisation of fuels and their use is a key element for the O&G sector to retain competitive financing over time. The focus is on natural gas, as most of the reduction from use of oil will come from a reduced demand due to alternatives (such as electrification of transport).
- **Scope 3 should also be a concern for Norway:** Nation-states have shown little appetite to take responsibility for scope 3 emissions to date, but as international carbon budgets dwindle fast pressures could increase. 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, the pressure on Norway as an exporter of emissions may increase accordingly. By decarbonizing fossil fuels upstream (in Norway) or supplying CCS equipment and expertise downstream (internationally) Norway will take more responsibility for reducing exported emissions and be on the right side of this narrative.
- **REPower EU and scope 3 emissions:** Norway will be a key provider of natural gas to the EU and aiding the diversification away from Russian gas. This reduces the near-to-mid term attractiveness of exporting decarbonized natural gas in the form of blue hydrogen to Europe, as the energy losses in its conversion and reduced energy shipped (by pipeline) are negative energy security factors. This bolsters the argument for decarbonizing the natural gas downstream instead. However, over time, there is a risk that energy efficiency gains in Europe also eats into Norwegian gas exports, while low-carbon hydrogen demand in the region grows. A one-sided focus on exporting natural gas may lead to Norway not moving early enough to establish competitive hydrogen value chains. Further, this may ultimately also lead to Norway being less in control of the scope 3 emission reduction narrative.
- **Natural gas power with CCS – Maximizing gas energy security impact:** Gas power with CCS could contribute substantially to reduce scope 3 emissions from Norwegian gas, either through deployment within or outside Norway. Within Norway, the main benefits would be the scope 1 emission reductions for oil and gas operators, an increased ownership for Norway in reducing emissions from produced natural gas, the potential for electrification of industry and NCS, combined with the creation of a CCS value chain and jobs. Outside of Norway, the main benefits are reduced losses from energy transmission – key for European energy security – as well as relatively higher near-term export revenue from maximizing gas exports. Outside of Norway, positioning Norwegian companies to take part in a European CCS value chain will be key to maximizing the value for Norway and the O&G sector and documenting ownership of scope 3 GHG emission reduction efforts.
- **Blue hydrogen and hydrogen derivatives – setting the stage for new industry:** Blue hydrogen and hydrogen derivatives would create value by decarbonizing fuel/feedstock upstream – enabling Norway to take firm ownership of scope 3 decarbonization efforts and would support the establishment of new hydrogen and CCS industry. That said, energy losses from conversion and transmission would negatively impact the amount of energy shipped to Europe, which could negatively impact energy security imperatives in the near-to-medium term.

Norwegian O&G industry can harvest the value potential of GHG emission reduction measures

The energy transition offers challenges, but also enormous business opportunities. To harvest the value potential of GHG emission reduction measures, the Norwegian O&G industry needs to take a leadership role in Scope 1, 2 and 3 decarbonisation solutions for the petroleum value chain now. This will i) provide a de-risked long-term business model in a low carbon world, ii) support the pace of the required global transition to reduce GHG emissions and iii) provide strategic value.

Financial value potential: A de-risked long-term business model in a low carbon world

1. **Norway's O&G industry as large exporter of GHG emission reduction technologies:** With already established access to global O&G markets, the Norwegian O&G industry is in a good position to export decarbonisation technologies and benefit of a large expected global potential.
2. **Prolonged production life and reduction of stranded assets:** Reducing GHG emissions will provide a competitive advantage vs. other O&G producers as Norwegian O&G producers can offer a more attractive product, thereby prolonging production life of existing Norwegian assets and reducing the risk of stranded assets.
3. **Continued access to capital, financing the energy transition:** Creating integrated energy players by (i) continuously reducing the emission intensity of its O&G operations and (ii) investing in low-carbon markets, the cost of capital could be lower for Norwegian companies than for more O&G pure-play competitors, helping finance the company's transition.
4. **Norway as the long-term provider of energy security to Europe:** Long-term demand for natural gas is uncertain. A leading role in fossil fuel decarbonisation solutions increases the partnership and cooperation with the EU and makes Norwegian gas a more attractive option to include in EU's pathway to net zero.

Emissions value potential: Support the pace of the required global transition to reduce GHG emissions

1. **Reduced emissions as a license to operate globally:** Recent examples of increased engagement from investors and activists highlight that reduced emissions are increasingly becoming a value driver. If the Norwegian O&G industry has the lowest CO_2e/barrel, and the gas is decarbonised downstream, it offers a low carbon value chain opportunity.
2. **Norwegian gas as a transition fuel for Europe:** Piped Norwegian natural gas has the advantage of relatively low life cycle emissions for European end-use vis-à-vis LNG imports. This will favour Norwegian gas as a transition fuel to replace coal and Russian gas and as an input to low-carbon fuels such as blue hydrogen/ammonia, as it is more likely to meet the gradually tightening requirements for natural gas to be EU taxonomy aligned.
3. **Pricing in externalities:** Mandatory disclosure requirements and scope 3 emissions reporting are forcing companies to show tangible contributions to global goals, and investors are increasingly pricing in transition risks. Products that can document such contributions will likely obtain preferential treatment and potential premiums in the market, creating new ways of adding value.
4. **Increased cooperation along the O&G value chain:** The scope 3 value potential offers a need and opportunity for increased collaboration across the full O&G value chain, from upstream to downstream and across borders.

Strategic value potential: Being a leader in decarbonisation solutions for the petroleum value chain

1. **Prolonged political support for O&G activities:** A sector that meets up to Norway's GHG emission reduction targets could expect longer political support, including financial support, than one that is not doing so.
2. **Taking decarbonisation responsibility by achieving 2030 and 2050 targets:** Cases of «green washing» in the global O&G industry is a serious risk to public perception. A Norwegian O&G industry that invests in its future by acknowledging its emissions and streamlining efforts to correctly measure and reduce them in line with ambitious targets, will ensure that Europe will look to Norway as a preferred supplier of O&G products.
3. **Retaining and attracting talent:** Labour is an essential ingredient in creating value, and sufficient access to skilled labour will require an industry with foresight. Ambitious, realistic and measurable reduction of GHG emission in line with 2030 and 2050 targets may attract a higher calibre of employees and board members.
4. **Jump on the megatrend of electrification:** The planned build-out of 30 GW offshore wind offers an opportunity to create synergies by e.g. developing a multi-purpose offshore grid. The result will be a deeper connection of the O&G industry to the power sector and heavy industry, sectors that will see a growing size of investments and therefore opportunities. By jumping on this trend, the Norwegian O&G industry is provided with increased future value creation.

What does it take?

Identifying actions that could help acceleration

- **The technologies exist but costs are still high:** The technologies to reduce GHG emissions by 50 percent in 2030 – and beyond – exist. However, the costs are still high and both scaling and further developments are needed. Financial instruments to support implementation, technology qualification and R&D could help de-risking and reduce technology cost.
  - As mentioned by KonKraft, examples of financial instruments could be: contracts for difference, as seen in the UK for offshore wind; establishing a CO_2 fund (where the increase in the CO_2 tax is earmarked for funding decarbonisation measures and developing new offshore industries); continuing the NO_x-fund; and strengthening the mandate of Enova and R&D programmes (e.g. Petromaks 2, Demo 2000, Climit) and centres (e.g. The Petrocenters and the LowEmission Centre)
- **Predictable and long-term policies help scaling and implementation:** The current political climate and debate on electrification of the NCS brings uncertainty. As cancellation or delay in planned power-from-shore projects will make it difficult to reach the 2030 targets, long-term and predictable policies are crucial in reducing risks.
  - The 30 GW target for development of offshore wind is an important first step in ensuring a large-scale development of offshore wind in Norway. To reduce uncertainty and risk, authorities should be clear on a step-wise roadmap for how the targets can be reached and start opening new areas for offshore wind.
  - Norway should increase its ambitions on development and implementation of clean technologies to position Norwegian industry and ensure a competitive advantage.
- **More robust frameworks and supporting measures can facilitate acceleration:** A robust regulatory framework needs to be in place to support strong deployment and provide long-term investment signals.
  - Robust frameworks for offshore wind development and clarity in basis for competition need to be in place to support strong deployment and provide long-term investment signals.
  - Clarity is needed in tax regimes for cross-over license areas between new industry (such as offshore wind or power hubs) and O&G assets, and how connections to the grid would impact this.
- **Solutions that enable a speedy transition:** Given current lead times on technologies as well as lengthy regulatory processes, the industry needs to **act now** in order to reach the targets in 2030. However, it is important to not lock in sub-optimal solutions for the long term.
  - Given the time needed for license and application processes, project development, as well as lead time of equipment, projects that aim to be operational in 2030 should conclude the feasibility stage gate (DG1) **before end of 2023**.
  - Both for developing new renewable and grid capacity, license and application processes should be reviewed and the capacity of proceedings should be strengthened. The EU has proposed measures to speed up the approval and development process of new renewable capacity, such as “go-to-zones”. As part of the EEA, Norway might be covered by this fast track permitting plan.
  - For an offshore grid build-out from shore, a short-term solution could be to start with radial connections that can later build into an offshore grid, similar to how the onshore grid has been built historically.
  - For CCS, new storage sites could be developed in parallel, and more license areas could be allocated. KonKraft also suggest establishing concrete targets for how much CO_2 should be stored on the NCS to ensure CCS becomes a commercial industry.
- **Strengthening measures to accelerate action:** Progress in reaching the emissions reduction targets should be closely monitored. If progress is lagging, support mechanisms can be combined with strengthening measures that increase the cost of emissions to accelerate action, in the form of higher CO_2 taxes or punitive measures. Such measures would ultimately reduce the long-term value of all O&G production and should be evaluated in light of both the energy transition and the current energy security landscape.
- **Cooperation can help optimise solutions and bring down overall costs:** Solving the issues at hand before 2030 requires cooperation between license partners and operators. Although more complex than individual solutions, this helps ensure a more optimal overall solution with lower overall costs. Good dialogue and simultaneity is key, as is data sharing to ensure transparency.
  - A coordinated approach – either an offshore power hub, large offshore wind farm or power from shore – can lay the foundation for a future meshed offshore grid that increases redundancy as well as new offshore industries in the longer term. KonKraft suggests Norwegian authorities should take an active role in EU’s work with development of frameworks for hybrid projects and the future masked offshore grid in the North Sea.
- **Create a strategy for the short- and long term:** When assessing solutions to decarbonise the petroleum value chain, it is important to think both short- and long-term. This means building a strategy that supports both decarbonisation targets towards 2030 while at the same time laying the foundation for transitioning from oil and gas revenue dependency into low-carbon energy carriers and new offshore industries, such as offshore wind and hydrogen production.

1. Introduction and background for the study

Identifying and prioritising options for Norwegian O&G to decarbonise

Background for project: Oil and Gas for the 21st Century – "OG21" – has commissioned DNV to produce this study on how the Norwegian Oil and Gas industry can meet its decarbonisation targets for 2030 and beyond. By the end of this project, **the study will have enabled OG21 to describe realistic ways to accelerate technology implementation required to meet the GHG emission reduction targets.**

Key objectives:

- **Technology insights:** Obtain a thorough understanding of potential greenhouse gas (GHG) emission reduction technologies, their technical and commercial readiness levels, application scope and scaling, and development and implementation obstacles
- **GHG emission reduction impact:** 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.
- **Creating and safeguarding value:** Describe the business opportunity for the Norwegian state as well as for Norwegian industry enterprises in taking a leadership role in petroleum decarbonisation 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 decarbonisation by ensuring Norway's world leading petroleum companies and solutions provide a competitive edge.

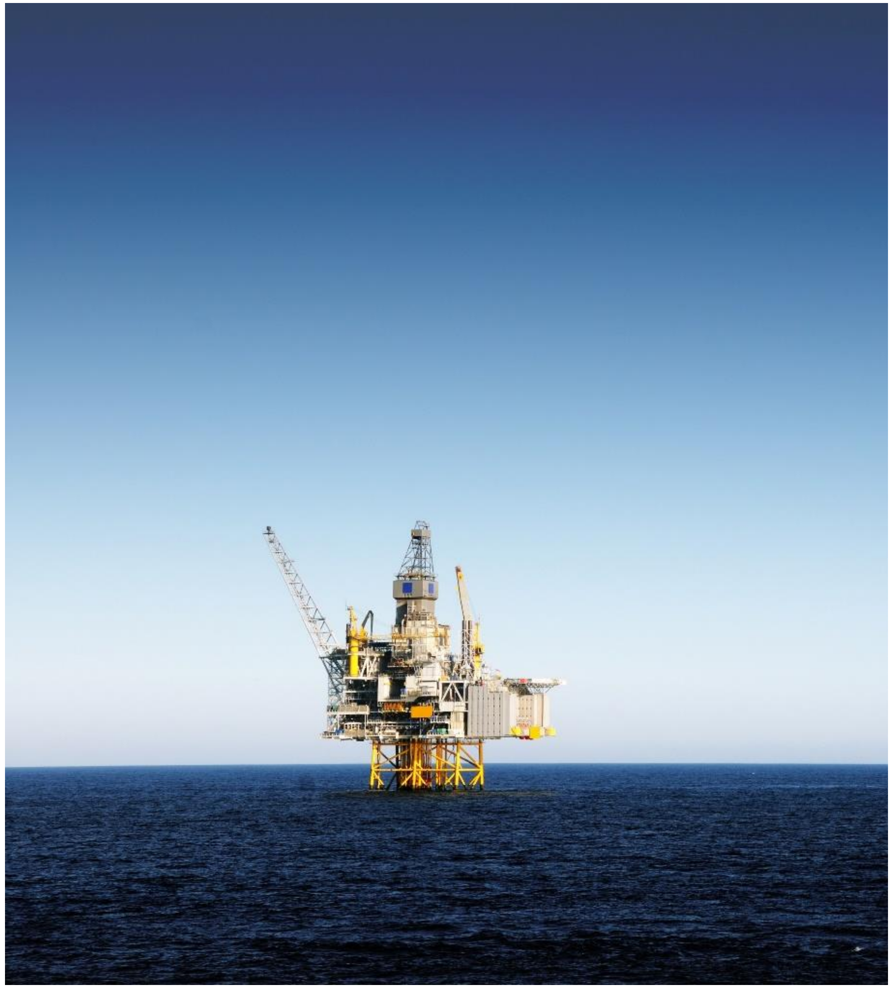


Image source: GettyImages - Morkemann

A chronological approach to identifying and prioritising solutions

Report methodology

- **Step-wise prioritisation:** The report will reflect the methodology of the study (see 1.3), through which a step-by-step narrowing down of a number of solutions seeks to identify the most promising solutions to decarbonise the Norwegian oil and gas sector.
- **Scope 1 focus, but scope 3 lens:** The main focus of the report is to identify solutions to reduce scope 1 emissions for oil & gas operators – which is the focus of steps 3-4 and 6, but step 5 and 6 will shed light on key considerations for scope 3 emissions, the evolving narrative of value-chain emissions responsibility and industrial opportunities.
- **Appendices:** Will elaborate on details for scope 1-3 emissions and solutions that were not prioritised. This is in order to ensure that steps 3-6 are reported as concise as possible.

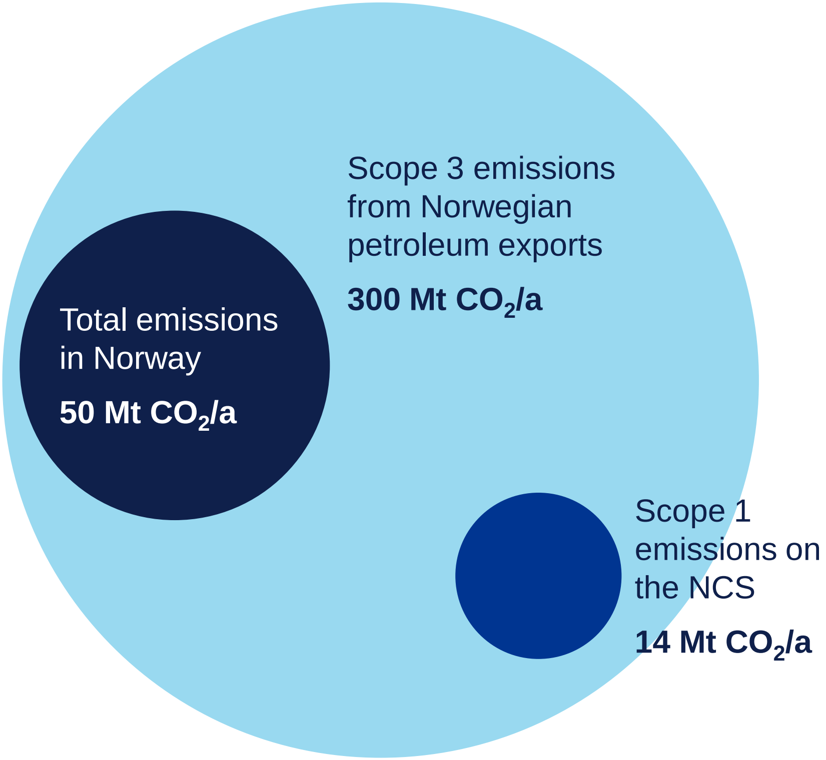
Meeting the 2030 GHG emission reduction targets require further measures

The Norwegian oil and gas industry has committed to reducing its scope 1 GHG emissions by 50 percent in 2030 compared with 2005, and near-zero in 2050. Moreover, there is increasing focus on decarbonising 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 of the 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

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 while building capacity for green 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 in the short- to medium term. In addition, the energy losses that results from converting gas to blue hydrogen, makes blue hydrogen less attractive during the current energy crisis. However, hydrogen production would support demand for low carbon fuels in the longer term, where the demand from hard-to-abate sectors is important.
- 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.

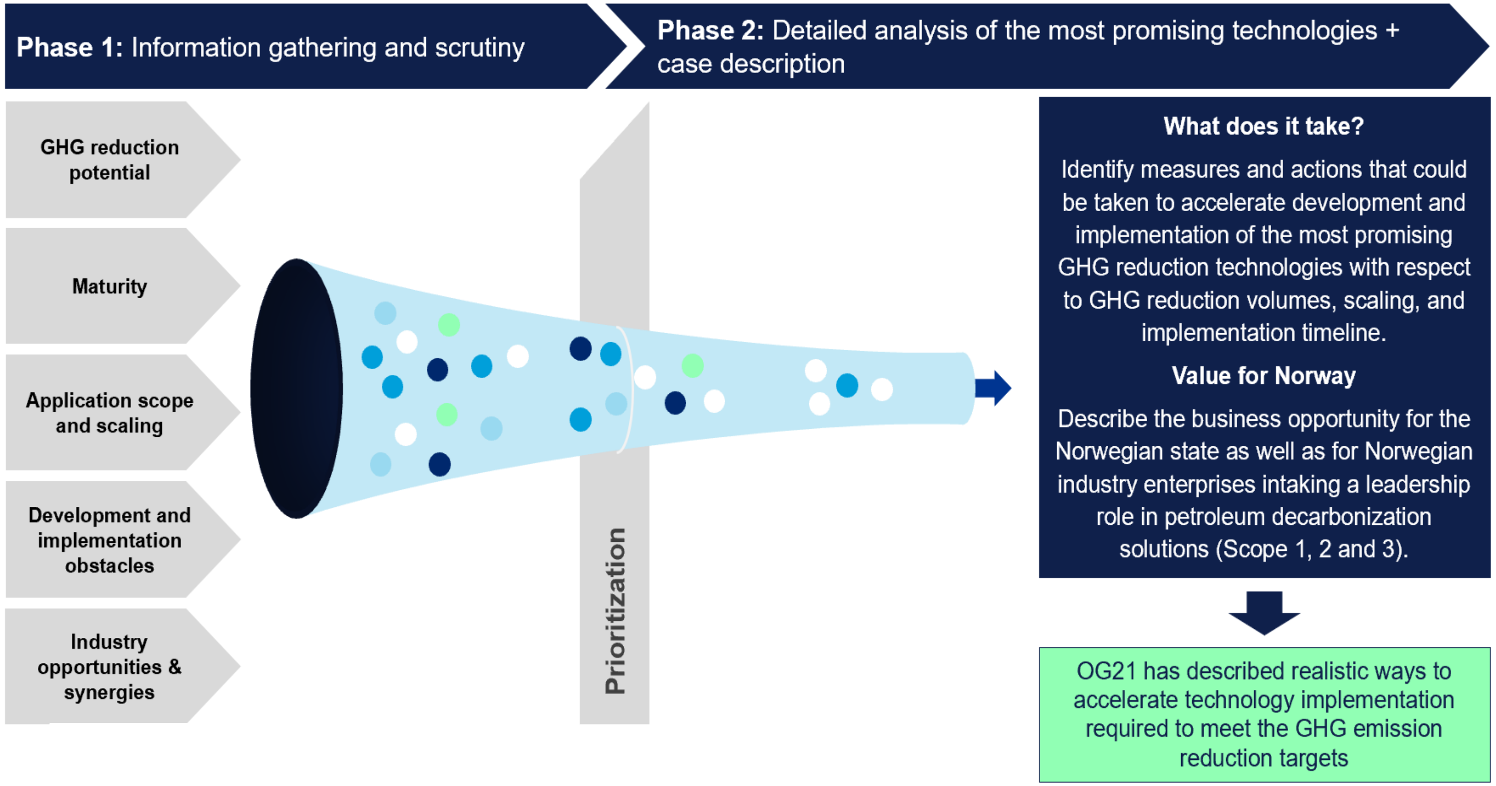
Narrowing a long-list of measures to the most promising decarbonisation options

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

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

In Phase 2, a more detailed assessment is done of the short-listed measures, including a case study. As part of this phase, DNV identifies important measures for accelerating development and implementation of the most promising measures ("What does it take?"), as well as describing 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.



Ensuring consistency between direct and indirect emission sources

Scopes 1-3: Direct emissions main focus of study

The GHG emission reduction targets for the NCS refer to the scope 1 emissions – which are direct emissions from the oil and gas industry. **Identifying measures to reduce these scope 1 emissions is the prime objective of the study and the focus of chapters 3 and 4.**

In order to ensure clarity and consistency, we apply the following distinctions between scope 1, scope 2 and scope 3 emissions in this study.

- **Scope 1 measures/technologies:** Qualitative and quantitative assessment of GHG emission reduction potential and scaling – looking into what it will take to meet the targets of the industry – is done in chapter 3 and 4.
- **Scope 2 measures/technologies:** Emissions stemming from purchased electricity are scope 2 emissions – thus indirect emissions as they occur outside of the control of the purchaser. While not a focus of this study, DNV notes that the carbon intensity of the Norwegian electricity mix was as low as 11 g CO2e/kWh in 2021– indicating very low location-based emissions from Norwegian electricity [1]. These emissions are related to physically delivered electricity and would differ for a market-based method. Oil and gas operators can also buy guarantees of origin to document zero market-based scope 2 emissions.
- **Scope 3 measures/technologies:** A more qualitative assessment of the impact of scope 3 emissions will be undertaken in chapter 5. This discussion takes a top-down approach on how Norwegian petroleum industry can work to reduce indirect value chain emissions (scope 3) occurring inside and outside Norway in order to safeguard its license to operate and competitiveness, by extension protecting the long-term value of the oil and gas industry against tightening sustainability pressures.

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.

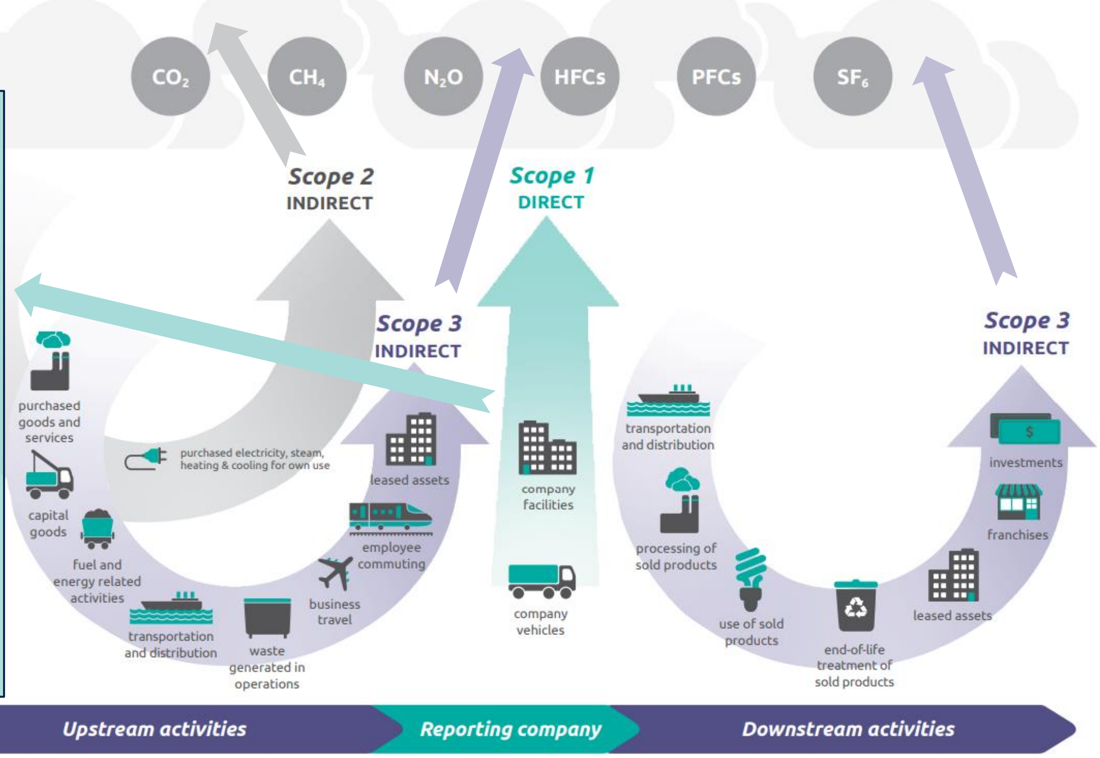


Figure: GHG Protocol

[1] NVE, Hvor kommer strømmen fra? - NVE (September 2022)

2. Setting the scene

Outline of chapter

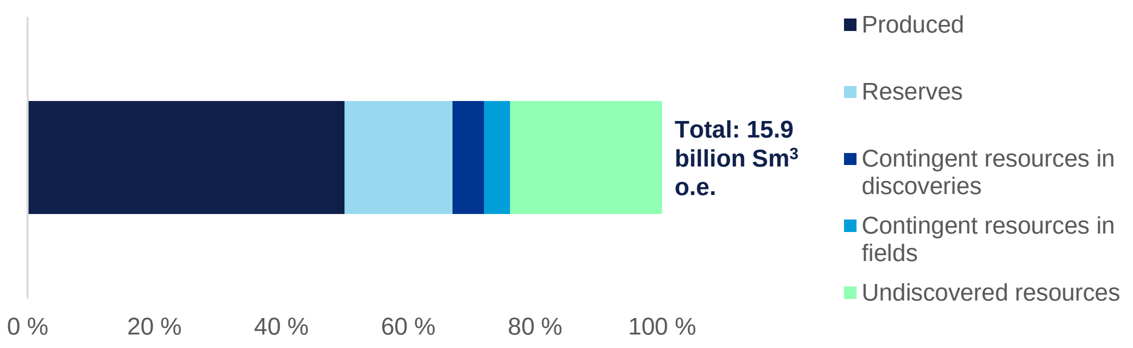
There is a rising sense of urgency that global decarbonisation efforts must accelerate substantially to limit global warming, in line with rapidly depleting carbon budgets. Against this backdrop, this chapter will look into several factors that are important for the continued decarbonisation of the Norwegian oil and gas industry, as well as its long-term value. These factors are in turn key variables to take into account when assessing the merit of various decarbonisation solutions in chapters 3-6. Chapter 2 will specifically look into:

1. **Fossil-fuel demand:** This chapter touches on the outlook for fossil fuel demand in the context of rising decarbonisation aspirations globally – and notably the outlook for Norwegian natural gas in light of the Ukraine conflict.
2. **Emissions from the NCS:** In addition to demand for fuels produced on the NCS, the emissions stemming from their production remains a sizable share of total Norwegian carbon emissions. This chapter will further discuss:
   - **Main sources of emissions on the NCS –** to identify where decarbonisation solutions must focus to reduce emissions.
   - **Top-level overview of decarbonisation solution options** – in order to set the stage for a deeper dive in the following chapters.

The NCS is characterised by still ample resources in smaller discoveries that need tie-back to maturing assets

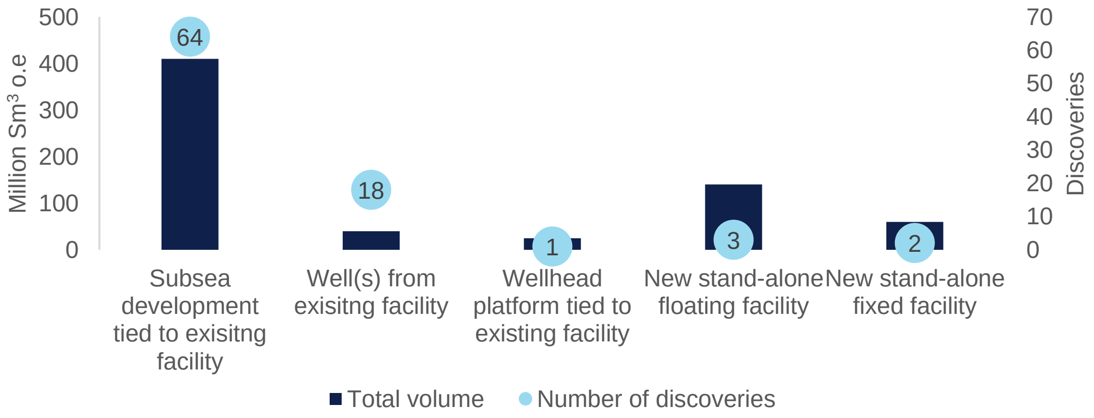
- **Large volumes of remaining resources:** Half of the estimated resources on the NCS has so far been produced, with around 26 percent remaining reserves or contingent resources, and 24 percent still undiscovered. The latter is dominated by the Barents Sea, with around half of the resources from unopened areas far North.
- **Maturing shelf with small discoveries:** The average field development size per decade has been declining rapidly – from 180 million Sm^3 o.e.in the 1970s to around 20 million Sm^3 o.e. today. At the same time, the average number of field development per decade has increased. In 2021, the discovery portfolio consisted of 88 discoveries, with the average size being small compared to other petroleum provinces globally. Most of the discoveries are too small to justify stand-alone developments, and would require tie-back to existing infrastructure.
- **Cost-efficient infrastructure ensures competitive break-even prices:** The break-even prices (USD/boe) on the NCS are competitive to other petroleum provinces globally. This is mainly due to low operational costs, caused by a cost-efficient infrastructure that is well suited for development of new resources in existing fields or near-field tie-backs. Utilizing (and possibly extending the life of) existing infrastructure contributes to cost-efficient developments, especially considering the small size of new developments that require tie-backs.
- **Low GHG emissions per barrel produced compared to global average**: The CO_2-intensity from production on the NCS (scope 1 emissions) are the lowest among petroleum provinces globally, with an average of 7 kg CO_2/boe produced. However, the production of O&G is a significant contributor to the total Norwegian GHG emissions (around 25 percent) and measures need to be taken to further reduce emissions in line with targets.
- The CO_2-intensity varies greatly within the fields on the NCS. Mature fields in tail-end with declining production (and more energy required for e.g. water handling) tend to have higher CO_2-intensities and also higher lifting costs per barrel. For some mature fields, shut-down might be preferred as the CO_2 tax can give negative field economics - especially with increasing taxes. However, most of the fields are interlinked and the shut-down case is a complicated decision that cannot be seen in isolation. Keeping the assets alive for some more years gives the licence flexibility to serve new nearby discoveries via tie-backs.

Resources on the NCS



Source: NPD, 2022

Most probable development solution for discoveries



Source: NPD, 2022

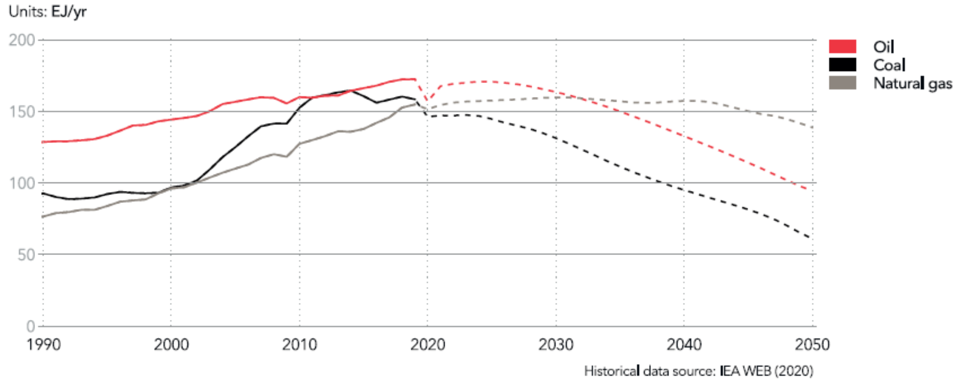
The content on this slide is based on information gathered from the OG21 Strategy

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 net-zero scenarios have been developed in the last decade, showing a wide span in projected oil and gas demand towards 2050. In DNV's newest Energy Transition Outlook (ETO) we estimate what we believe to be the most likely future of oil and gas demand given current policies and developments. Our estimates show 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. Oil demand is expected to have a steeper decline.
- It is however important to note that the ETO shows we will not reach the Paris targets in time, and that we are heading for a global warming of 2.3 degrees. In order to reach the targets, both oil and gas demand needs a more rapid decline than estimated.

World primary fossil fuel supply by source

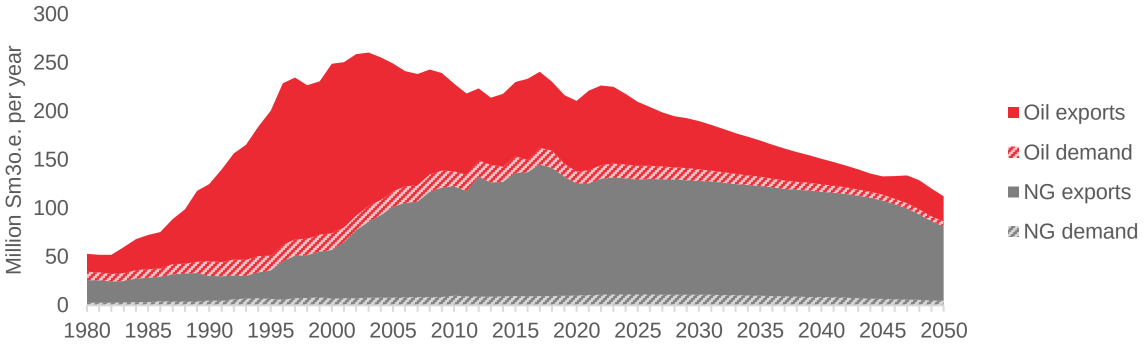


Source: DNV ETO (2021)

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 percent 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



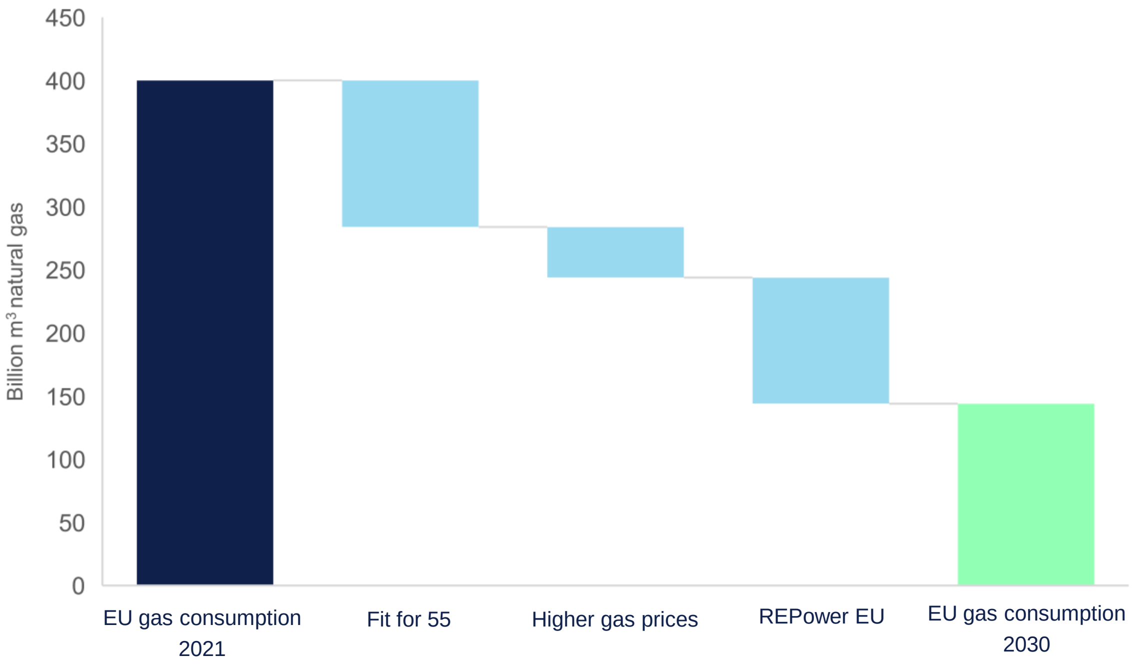
Source: DNV ETN (2021)

1) DNV Energy Transition Norway (2021)
2) https://www.regjeringen.no/no/aktuelt/pm-tilleggsmelding/id2908251/

European demand for natural gas could be significantly reduced long-term

- 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 use of 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 highlight 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 emissions and energy losses than piped natural gas from Norway. As an example, estimates from KonKraft show that upstream and midstream emissions from LNG produced in the US and imported to Europe are around 8 times higher than piped natural gas from Norway [2]. With further reductions in GHG emissions through decarbonisation measures discussed in this report, the competitiveness of piped gas from Norway can be strengthened and thereby become the preferred source of natural gas supply towards EU’s pathway to net zero.

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

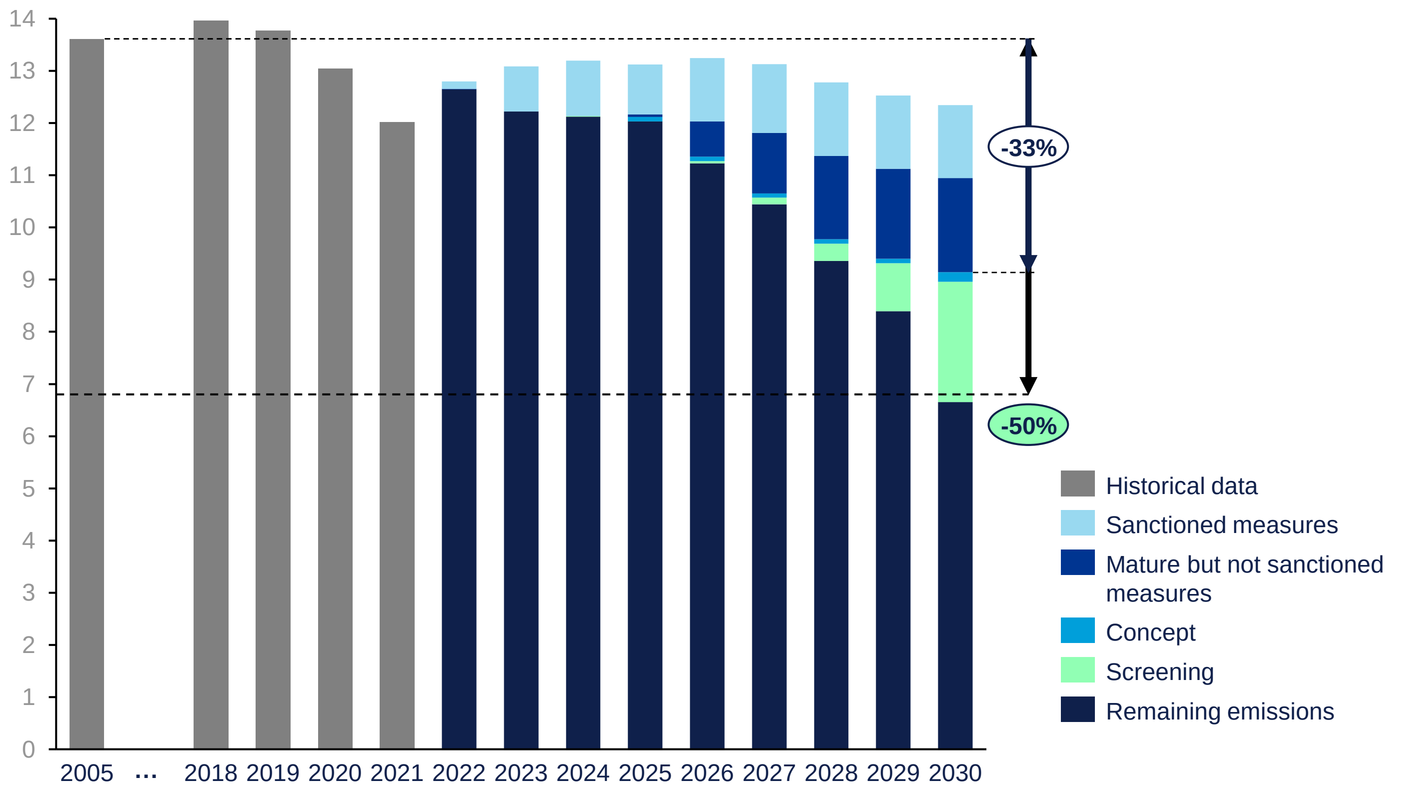
[1] Energi og klima, 25.05.22, https://energiogklima.no/nyhet/brussel/eu-notat-dramatisk-kutt-i-eus-gassbehov-etter-2030/

[2] KonKraft, Status update (2022)

With current sanctioned and mature measures, emission levels are set to be down by 33 percent in 2030, from 2005 levels

- Implementing a combination of measures that target the largest emission sources on the NCS is key to reduce emissions in accordance with targets. The KonKraft status reports give a yearly overview of the status towards reaching the GHG emission targets in 2030 based on measures with varying degree of maturity reported by the operators. In the newest update, an emission reduction potential of 50 percent in 2030 compared to 2005 is shown to be achievable.
- However, only 33 percent of the reduction potential is expected to come from measures that are currently sanctioned or mature (nearing investment decision). A large portion – around 17 percent - is expected to come from measures in the screening phase, which are described as highly uncertain. As such, in order to reach the 50 percent reduction target in 2030, more effort is needed in maturing concepts and scaling up their implementation.
- Moreover, as the projection illustrates, a large majority of emission reductions leading up to 2030 must occur already from this year, with an accelerating impact envisioned post-2025. Any delays or cancellations will postpone the decarbonisation
- Finally, having a suite of measures that take the potential reductions beyond 50 percent is also essential in order to offset the risk that certain measures are not implemented. As such, a key objective of this study is to supplement additional decarbonization measures for the NCS in order to support decarbonization towards 2030 and beyond.

Historical and forecasted emissions on the NCS and onshore facilities
[million tonnes CO_2eq/yr]

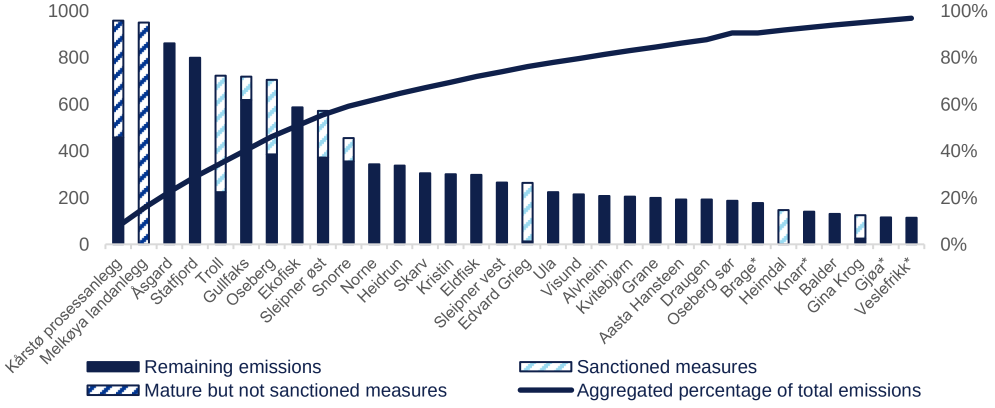


Source: KonKraft (2022)

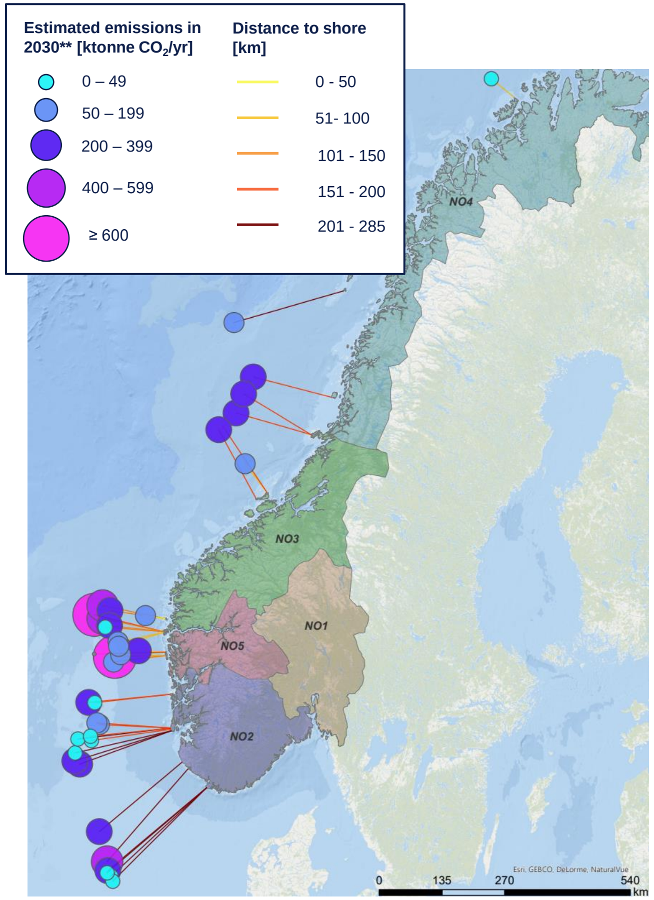
Tackling large emitters is a must for delivering on looming 2030 climate targets

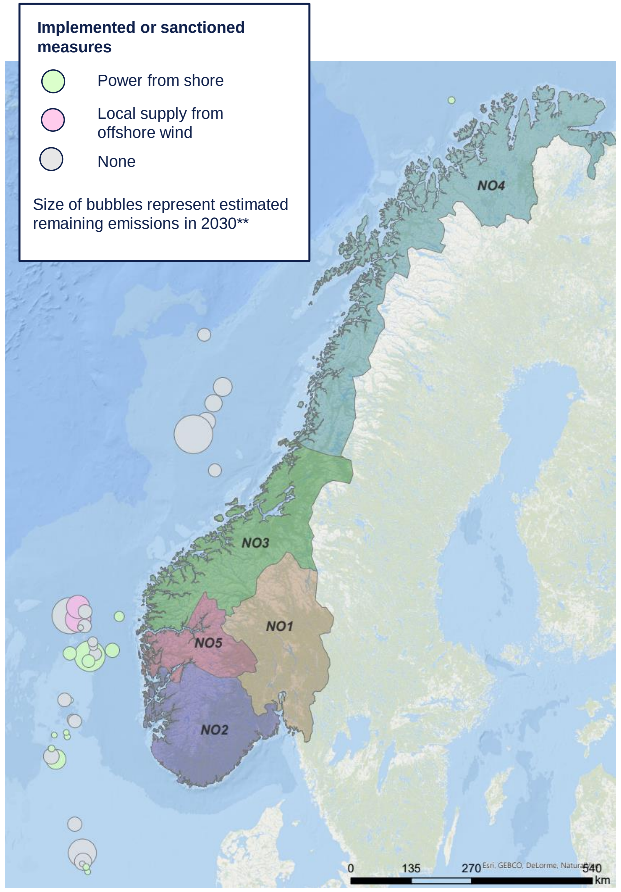
- The graph below show that out of 50+ registered fields and onshore facilities, the eight largest emitters* represented over 50 percent of the total emissions in 2020. Even with sanctioned measures, the emission levels in 2030 are still high and for two of the largest emitters, no mature measures exist. **Without significant emission reductions on the largest emitters, the climate targets will be extremely difficult to achieve.**
- Looking at the map, it is evident that power from shore is by far the most common measure for reducing emissions and that these installations are located closer to shore (with the exception of Utsira-høyden, Valhall and Martin Linge).
- There are several hot spots with high emissions where the installations are located further from shore (above 200 km). Electrification through power from shore on these installations is more complex.

Forecasted yearly emissions per field in 2030 with sanctioned and mature measures**
Compared to 2020 emission levels.
[thousand tonne CO_2eq/yr]



Fields marked with '' represent fields with uncertainty of continued operation past 2030





Maps and graph by DNV

*Mongstad refinery is not included in the data due to ongoing discussions on decommissioning.

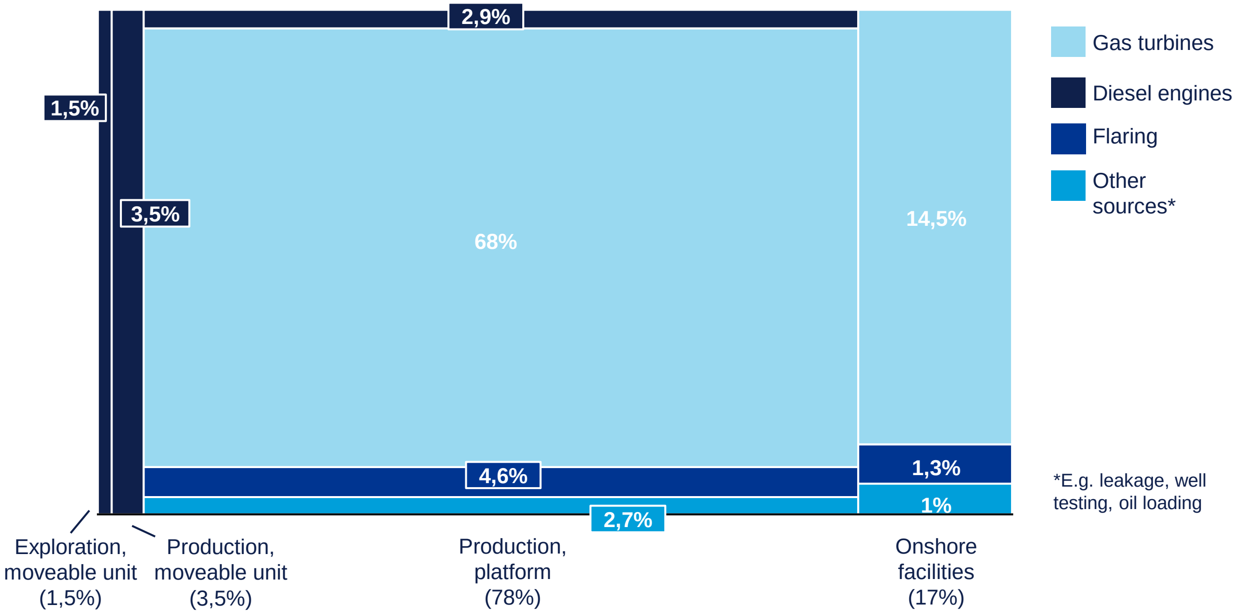
**Data on measures and associated emission reduction potential in 2030 is based on publicly available information and outspoken targets from the operators. As such, some measures might not be captured in this overview. Moreover, smaller energy efficiency measures have not been included. Historical emissions data (2020) from Miljødirektoratet.

DNV

Gas turbines account for around 83% of total scope 1 emissions

- 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 percent of total scope 1 emissions occurred from platforms on producing fields, while 17 percent occurred during onshore activities.
  - **Emission sources:** Fuel combustion in gas turbines is by far the largest source of emissions, with 83 percent of total scope 1 emissions coming from these turbines in 2019 (68 percent from platforms and 15 percent from onshore facilities).
- As such, the main focus area when reducing scope 1 emissions on the NCS (and onshore facilities) should be to reduce emissions from the gas turbines. This can be done through several measures, including (1) reducing the energy demand, (2) reducing the gas turbine combustion emissions, and (3) replacing the gas turbines with electrical power.
- Reducing emissions by reducing fuel consumption of natural gas will also free up gas for export to Europe. Alongside creating additional revenue from gas sales, the gas can be used more efficiently. KonKraft has estimated that emissions from gas turbines on the NCS are in average 70 percent higher per kWh produced than an average gas-fired power plant in the EU. Compared to use in buildings and other sectors, the emissions from gas turbines on the NCS are twice as high [1]. This shows the importance of comparing different solutions for global emission reductions in a system perspective.

Scope 1 emissions from the NCS in 2019, by emission source and activity
[% of total Mt CO_2-eq emitted]



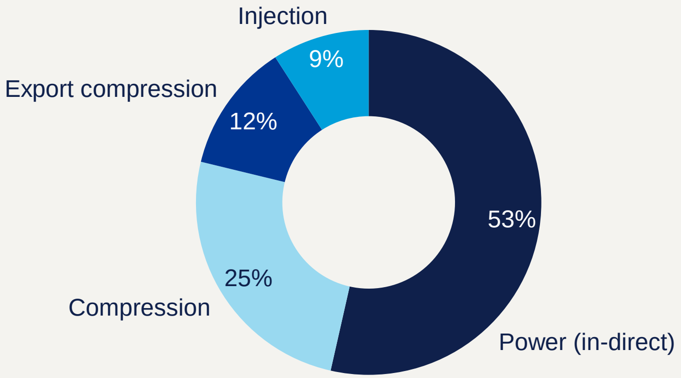
*E.g. leakage, well testing, oil loading

Source: SSB, figure inspired by Rystad Energy (2019)

[1] KonKraft, Status update (2022)

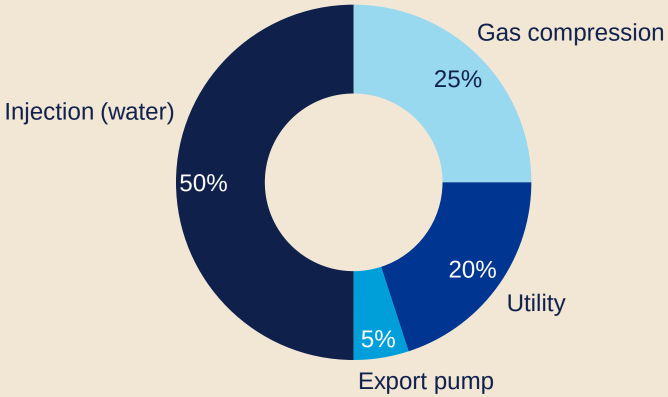
The turbine related power consumption varies depending on field and load type

GAS FIELDS



- More than 50% of the normal turbine load is related to power generation used for utility and compression. These power generator turbines are not directly driving any other equipment than the generator and can be more easily replaced with electric power. This is known as part-electrification.
- Larger equipment, like compressors for gas export or pumps for injection of water, are sometimes directly driven by mechanical power. The turbines driving the equipment is commonly referred to as direct drive or mechanical drive gas turbines. Replacing these turbines requires more extensive modifications on existing platforms, resulting in more downtime and higher costs.
- 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



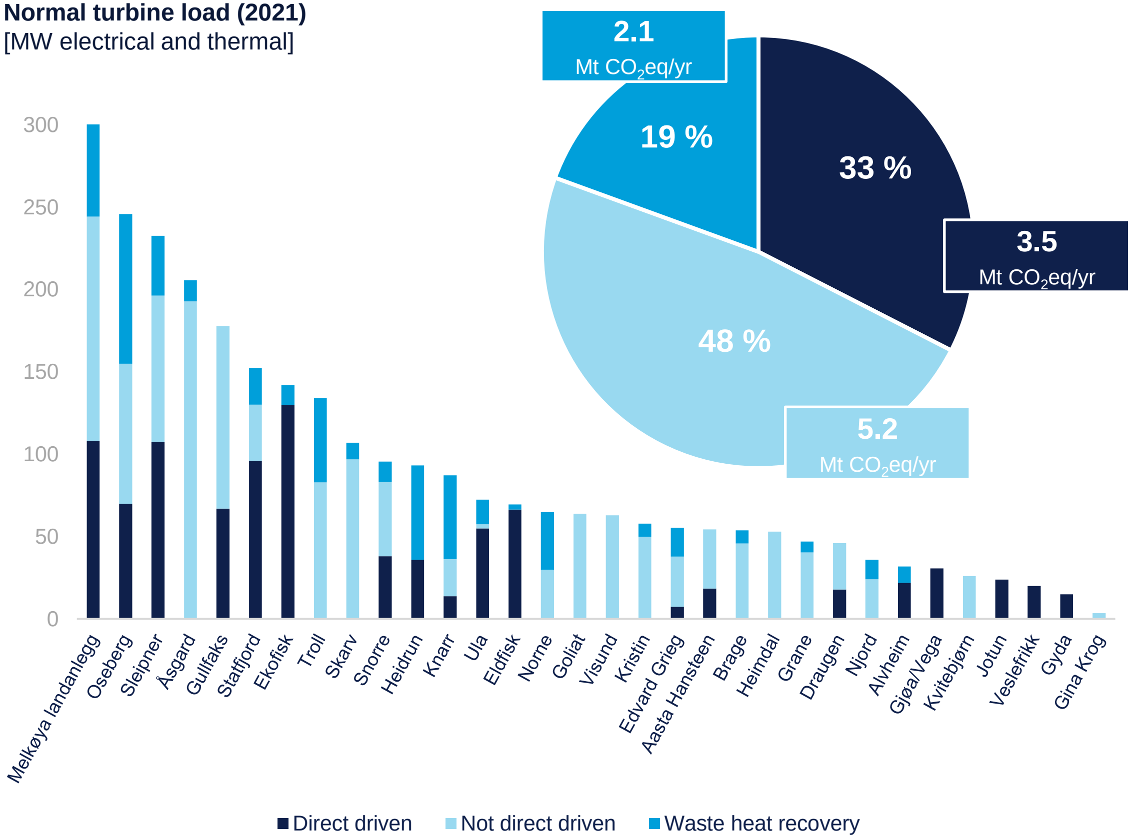
- On typical oil fields, water injection is the most energy intensive operations.
- Gas compression for transport is the second largest energy intensive operation, and together with water injection this accounts for around 75 percent of gas turbine emissions from oil fields [1]. If measures can be taken 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)

[1] Rystad Energy, Technologies to improve NCS competitiveness (2019)

Efforts need to be made in reducing harder to abate emissions in order to reach targets

- The figure to the right shows the normal turbine load per installation based on turbine data from NPD. The turbines are categorised by whether or not they are used to directly drive load, as well as the amount of waste heat recovered from the turbines used on the installation. Note that not all installations were represented in the database.
- When considering measures for replacing gas turbines, such as electrification, focus should first be on replacing the non-direct driven load. This is due to the fact that replacing turbines used to drive load requires more extensive modifications on existing installations.
- According to the data by NPD, the turbines running non-direct driven load amounts to around 48 percent of the total normal turbine load. If scaling this percentage to the total emissions from gas turbines on the NCS and onshore facilities in 2020, around 5.2 million tonnes of CO_2 could potentially be reduced. Compared to total emissions, this constitutes a **40 percent reduction potential***.
- As such, in order to reach the 50 percent emission reduction targets in 2030, **efforts also need to be made in reducing harder to abate emissions**, i.e. from the turbines driving load. However, this comes with more costly modifications and (in some cases significant) downtime with resulting loss in revenue.

Normal turbine load (2021)
[MW electrical and thermal]



Source: Data received from NPD on turbines installed on the NCS and onshore facilities

*Note that this is a very simplified estimation and that the exact reduction potential is highly case dependent.

Key takeaways

Fossil fuel demand

Norwegian gas demand stronger for longer: It is uncertain to what extent oil and gas demand will fall leading up to 2050. From a Norwegian perspective, European demand for natural gas is set to be more robust in the near-term, given EU aims to rid itself of Russian gas by 2027. Piped Norwegian gas will be cheaper for the EU than imported LNG, helping to ensure a European market for Norwegian natural gas.

Pace of EU gas demand contraction still a key question-mark: On the other hand, EU aims to significantly cut gas demand could also eat into Norwegian exports over time, and according to the European commission, the combination of high gas prices and FiT-for-55 and RePower EU measures (such as energy efficiency and rollout of alternative forms of energy) could lead to a gas demand contraction by 2027 beyond that of Russian gas imports. This poses a risk to Norwegian gas exports.

GHG emission reductions

More measures needed: KonKraft estimates that an NCS emission reduction of 33 percent is likely by 2030, compared to 2005 levels. This includes sanctioned measures, as well as measures that are relatively mature. Through adding measures currently in the concept/screening phase – a 51 percent GHG reduction is projected. As it is unlikely that all immature measures will be implemented, developing additional prospective measures is essential to delivering a 50 percent reduction by 2030.

GHG reduction measures must focus on gas turbines and big emitters: With gas turbines making up around 83 percent of scope 1 emissions on the NCS and onshore facilities, and eight O&G installations making up over 50 percent of total NCS emissions, it is clear that measures must target emission stemming from gas turbines and largest emitters to deliver on targets. This can be done through several measures, including (1) reducing the energy demand, (2) reducing the gas turbine combustion emissions, and (3) replacing the gas turbines with electrical power.

Image source: Thinkstock

3. Prioritising measures to reach GHG emission reduction targets

Outline of chapter

Identifying and prioritising measures: Implementing the most impactful decarbonisation measures to reduce scope 1 emissions from the NCS will be key to enable the Norwegian oil and gas industry to meet its target of reducing GHG by 50 percent by 2030 compared to 2005 levels. This chapter outlines the process undertaken in this study to identify potential measures to enable scope 1 emission reductions, as well as the rationale informing the prioritisation of certain measures. The chapter is structured as follows:

1. **Overview of prioritisation process:** A top-level overview of the process undertaken to identify and short-list measures is provided. Notably, a long-list of measures was identified by DNV experts and discussed in detail through workshops with the OG21 technical groups. This culminated in a short-list of the measures with the highest anticipated decarbonisation impact.

2. **Detailed comparison of measures:** As a component of the prioritisation process, the long-list of measures were compared across several factors, specifically GHG reduction potential, maturity, application scope and scaling potential, development and implementation obstacles and industry opportunities and synergies. This section of the chapter will outline how the prioritised measures were scored across these factors. The overview for non-prioritised measures can be found in Appendix C.

3. **Prioritised measures:** Finally, this chapter will outline the background and detailed scope for three grouped measures deemed to have the highest potential for reducing emissions from the NCS – these are:

   - **Electrification:** This section will tackle the electrification debate in Norway, and look at the scope for power from shore through a coordinated approach, power from shore through an individual approach as well as local supply from offshore wind.
   - **Gas-fired power hubs with CCS:** This section will look into the scope for gas-fired power hubs with carbon capture and storage, and how such a solution could help bolster NCS electrification and the Norwegian CCS value chain.
   - **Energy efficiency through water management:** This section will dive into the scope for reducing energy demand through more energy efficient water management strategies, e.g. reduced water production by improved reservoir understanding, well conformance and downhole water separation and re-injection.

Image source: iStock

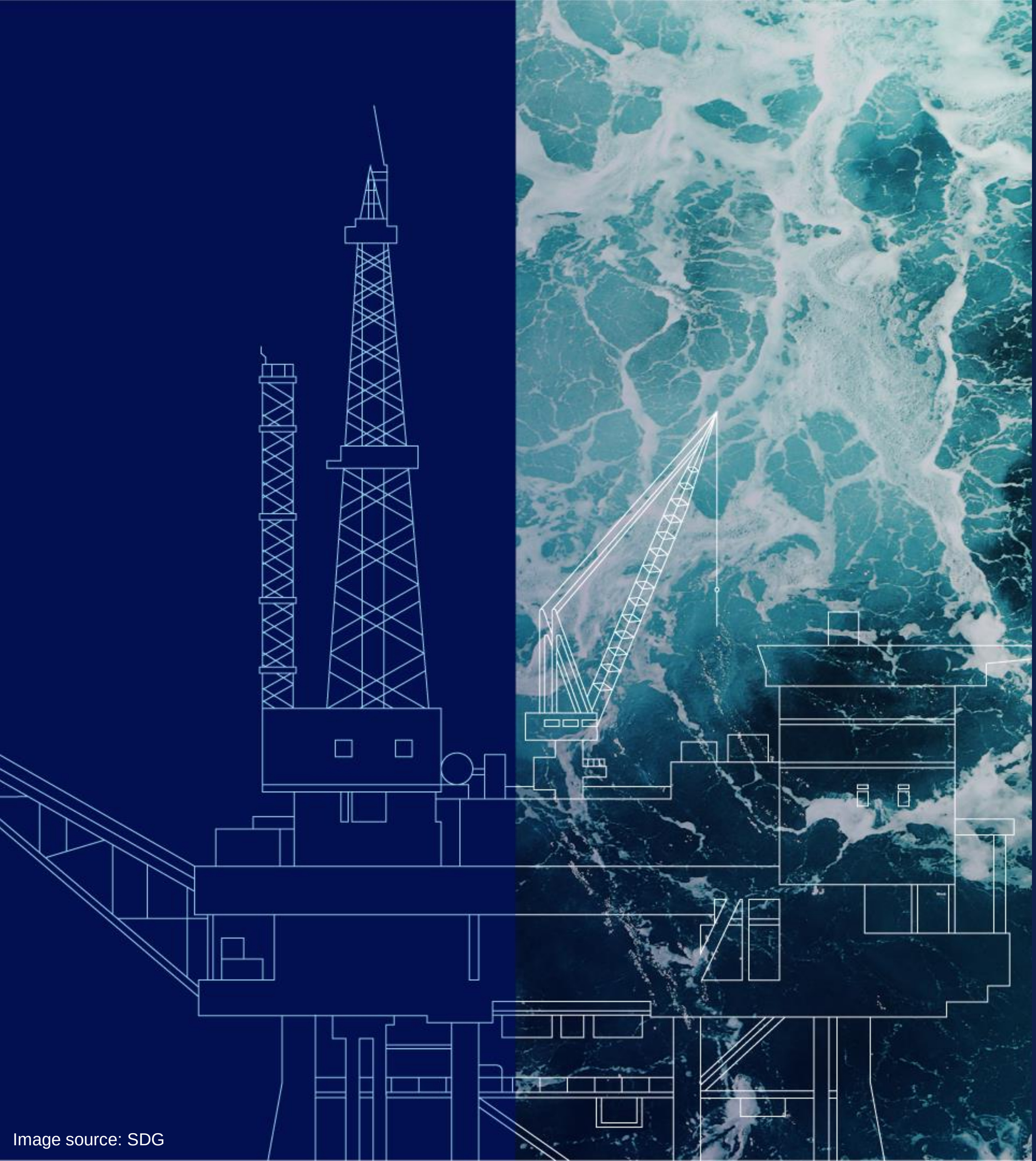


Image source: SDG

3.1

GHG reduction measure prioritisation overview

Overview of prioritisation process and results

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

Overview of measure assessment approach

- **Technology comparison:** 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 project. This assessment has been undertaken through an iterative process whereby DNV experts have evaluated the various technologies across a set of screening criteria presented in the tables in the following pages, with opinions having been informed and qualified through input provided by OG21 experts in technology assessment workshops with all five OG21 Technology Groups (TGs).

- **Scoring methodology:** Technologies have accordingly been scored by applying a “high”, “medium” or “low” traffic light methodology across the set of criteria listed (see next page) – where high is the most positive and low is the most negative. The aim behind this methodology is to take a holistic view on the overarching potential of each technology, as well as to specifically identify and visualise potential barriers and opportunities.

- **Shortlist:** On the basis of this scoring, the long-list of technologies was shortened to constitute some technologies that qualified for a deeper-dive in the second stage of the project (chapter 4). **It is important to note that although some technologies are not part of the short-listed measures in this report, this does not mean that DNV does not see a potential for scaling these technologies offshore.**

From long-list to short-list

Long-list of decarbonisation measures

Replacing gas turbines through electrification

- Electrification: Power from shore (coordinated approach)
- Electrification: Power from shore (individual approach)
- Electrification: Local supply from offshore wind
- Gas-fired power hub with CCS

Reducing emissions from the gas turbines

- Compact topside CCS
- Hydrogen and hydrogen-derived fuels for power production
- Optimized gas turbines: Utilisation

Increasing the energy efficiency*

- Energy efficiency through reservoir management: Water management
- Energy efficiency through reservoir management: Artificial intelligence
- Energy efficiency through reservoir management: CO_2-EOR
- Optimized gas turbines: Waste heat recovery
- Geothermal energy to reduce electrical power demand offshore

Short-listed measures to be prioritised

- **Electrification: Power from shore (coordinated approach)**
- **Electrification: Power from shore (individual approach)**
- **Electrification: Local supply from offshore wind**
- **Gas-fired power hub with CCS**
- **Energy efficiency through reservoir management: Water management**

Prioritisation process

Based on input from OG21, DNV identified a long list of measures for reducing scope 1 emissions on the NCS and for onshore facilities. The long list of measures were discussed in five separate half-day workshops with each Technology Group (TG) in OG21, as well as in a joint whole-day workshop comprising all TGs, and assessed on a high level based on a set of screening criteria using a “high, medium, low” scoring methodology (see page 41-43). Other measures that where discussed but not chosen can be found in Appendix C.

On the basis of the input from the workshops with TG’s, as well as a scoring assessment by DNV, the measures listed in the long-list were narrowed down to a short-list of measures. These measures have received the main focus of this study, as the ones with the biggest potential to help accelerate decarbonisation on the NCS.

*Energy efficiency measures are often low-hanging fruits in terms of reducing emissions, as they can be well-known and easier to implement within a relatively short time horizon compared to other large-scale emission reduction measures. Several energy efficiency measures exist, and we have highlighted a few important ones here. However, more measures exist and the operators are continuously working on assessing and implementing these. In this report, it is assumed that the operators will investigate other opportunities on an individual basis (see also Appendix C).

Rationale for prioritised measures

Based on a screening and comparison of measures, the table below lists the measures that were selected for an in-depth assessment due to their relatively high potential to drive GHG emission reductions on the NCS before 2030. **The three decarbonisation measures are discussed in detail in this chapter.**

Prioritised decarbonisation measure	Reasoning
Electrification: Coordinated or individual electrification from onshore grid, and local supply from offshore wind	• 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 batteries and hydrogen for energy storage. • 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.
Gas-fired power hub with CCS	• Onshore: Decarbonising onshore gas power plants, with offshore CO_2 storage is a good measure 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.
Energy efficiency: Water management	• As seen on slide 31, water injection is one of the most energy intensive operations. Reducing the energy consumption for water injection is therefore seen as one of the key measures for reducing CO_2 emissions. • The most efficient way of reducing energy consumption for water injection is in avoiding water in-flow entirely, which needs to be done during planning of reservoir depletion strategies. As such, highest potential for new fields although technologies exist to limit energy use for water management also in mature fields. However, it is important to note that assessing the potential of water management is difficult as it is extremely case dependent.

Rationale for not prioritising measures

The table below lists the measures that were screened out for various reasons, including costs, maturity, scaling potential and timeline, and application volume. **These measures are not discussed further in this chapter, but are covered in Appendix C**. It is important to note that although these measures are not part of the same in-depth assessments as was given the measures listed on the previous page, 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.

Non-prioritised decarbonisation measure	Reasoning
Hydrogen and hydrogen-derived fuels for power production (gas turbines)	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.
Compact top-side CCS	Significant technical limitations (weight and space) and would therefore likely be applicable only to a few brownfield FPSOs. As such, this is not seen as an important measure on the NCS as of now. However, there might be interesting cases internationally and the compact technology investigated might prove valuable to facilitate developments within carbon capture technologies.
Optimized gas turbines: Waste heat recovery and optimizing utilization	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	Limited opportunities, limited access to infrastructure, substantial costs, limited emission reduction potential.
Energy efficiency: Artificial intelligence	Limited direct emission reduction potential.
Geothermal energy	High costs and limited potential for geothermal energy to reduce emissions through electrification offshore.

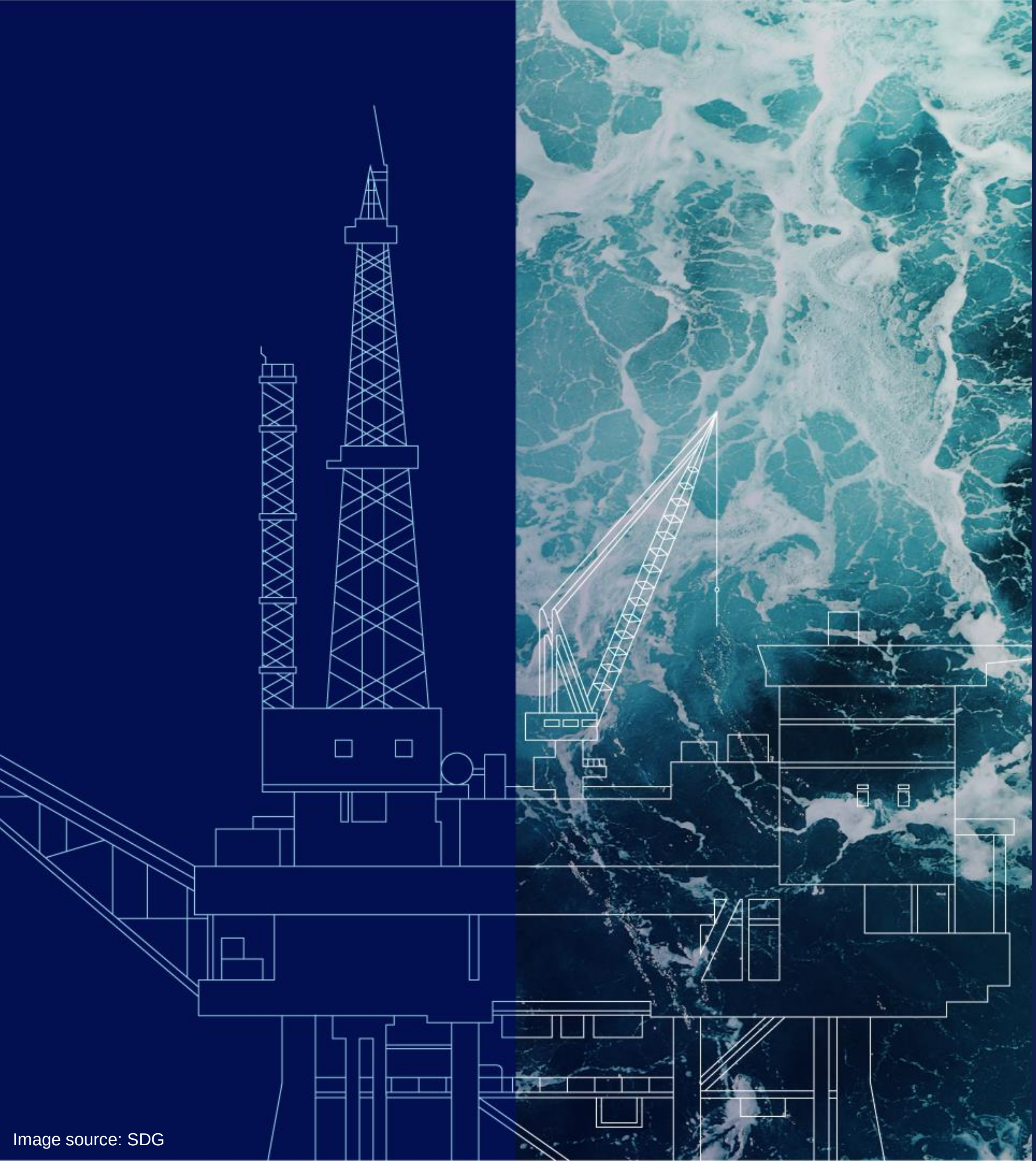


Image source: SDG

3.2

GHG reduction measures: Detailed comparison

Introduction to assessment approach
Screening criteria informing measure prioritisation

Criterion	Description
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 measure • **The application and scaling potential**, i.e. the realistic percentage of targeted emission sources that could be replaced by the chosen measure, given the assessed scaling potential.
Maturity	The **maturity** is assessed based on the Technical Readiness Level (TRL) of the measure, 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 measure 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 measure.
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 measure as well as possible synergies.

 Image source: Adobe Stock

High	Medium	Low

Electrification – Comparison of measures

Decarbonisation measure 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 scope 3 synergies Medium: Limited scope 3 synergies Low: No 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 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	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.	Limited potential for optimization.
Electrification: Local supply from offshore wind	Replacing gas turbines (partial electrification)	Under development, Hywind Tampen to be connected in Q3 2022	For shared license areas some clarifications could be needed	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 if used to produce renewable H2 and NH3

High	Medium	Low

Gas-fired power hubs with CCS – Comparison of measures

Decarbonisation measure 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 scope 3 synergies Medium: Limited scope 3 synergies Low: No scope 3 synergies	
Gas-fired power hubs with CCS (offshore)	Replacing gas turbines (partial or full electrification) where direct electrification is difficult	Existing technology but not applied offshore	Needs offshore testing, complex value chain	Cost of power hub, development of value chain, maintenance, access to storage	Norway taking lead in CCS value chains, benefiting from Northern Lights	Assumes used on fields not reachable from shore due to high costs	Reducing category 11 emissions (assuming gas comes from companies on NCS).	Can be part of hub for coordinated electrification, increasing scope 2 emissions compared to electrification from onshore grid
Gas-fired power hubs with CCS (onshore)	Replacing gas turbines (partial or full electrification)	Existing technology	Needs value chain development, possible before 2030 if attached to Northern Lights	Political and societal acceptance, development of value chain, access to storage	Norway taking lead in CCS value chains, benefiting from Northern Lights	Brownfield limitations (space, weight, Hz). Depends on partial or full electrification.	Reducing category 11 emissions (assuming gas comes from companies on NCS)	Can be part of individual and/or coordinated electrification, increasing scope 2 emissions compared to electrification from onshore grid

High	Medium	Low

Water management - Comparison of measures

Decarbonisation measure 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 scope 3 synergies Medium: Limited scope 3 synergies Low: No scope 3 synergies	
Water management for stable displacement (w/o chemicals)	Reducing power consumption from injection	Technology available, high cost	Mature technology already applied today	High costs	Existing technology, improvement opportunities	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)	Reducing power consumption from injection		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	Reducing power consumption from injection. Reducing weight of fluid column and need for gas compression gaslift		Mature technology. Cost benefit considerations		Well technology opportunities	Only applicable for oil fields. High potential for end-of-life brownfield.	No synergies	Downhole water management, well technologies

3.3

Electrification: Background

Electrification debate sets key parameters for oil and gas decarbonisation options

- **Electrification is key:** Electrification of oil and gas platforms through power from shore is considered a key measure to achieving the emissions reduction targets in 2030. In fact, as outlined by KonKraft's 2022 report, a large majority of electrification measures sanctioned or in planning centres on power from shore to date (see 3.4).

- **Anticipated undersupply:** However, due to a slower build-out of new power capacity compared to the expected increase in power demand, Statnett expects the historical power surplus to be reduced and reach a low-point already in 2026 – with only 3 TWh of power surplus. Moreover, the grid is already constrained in several areas, and large investments will be needed in the onshore grid capacity to enable supplying offshore platforms from shore.

- **Heated political debate:** As such, there is a heated political debate on how to allocate dwindling power supplies. Grid constraints, historically high power prices and anticipated continued domestic bidding zone price combined with a challenging geopolitical landscape has further complicated the electrification discussion. These factors all play a key role in influencing perspectives on how the power grid should be developed and whether the NCS should be electrified from shore – or by other means.

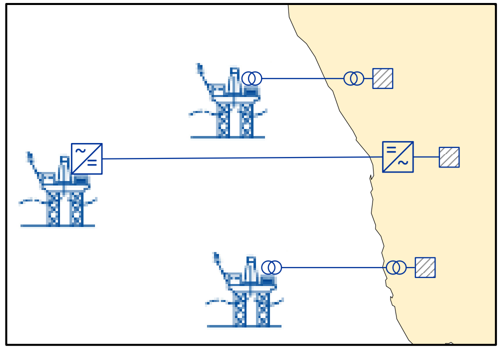
- More details about the electrification debate and power market in Norway can be found in appendix B.

DNV

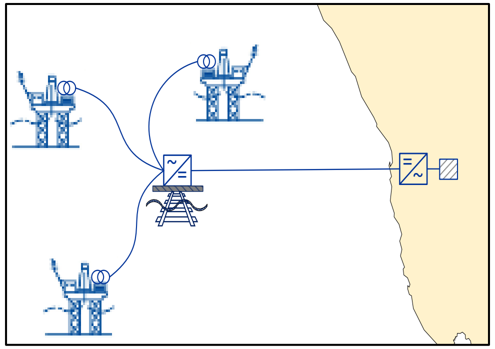
Overview of (some) electrification options

There are several measures for electrification of offshore energy consumption, which can be combined in numerous ways. When it comes to network design, there are some fundamentally different options to supply the relevant offshore energy consumption: individually, coordinated, or through local supply. A coordinated and individual approach represent mutually exclusive alternatives while the local supply approach can be combined with both. In this chapter, we try to highlight some generic features of the different design approaches.

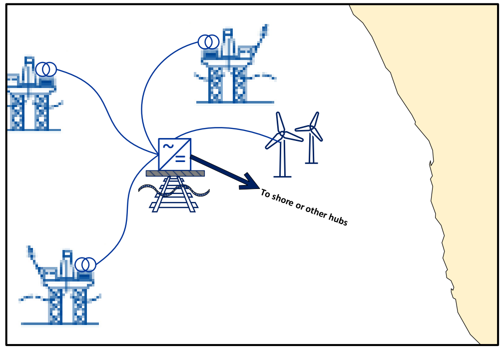
Individual design approach: Each field is supplied through a radial connection to shore. Note that this concept could also include local supply connected directly to the platform (see "local supply approach").



Coordinated design approach: Numerous fields are supplied via a common offshore energy hub with power from shore. Note that the hub could also include a local supply option (see "local supply approach"). Connection to an offshore meshed grid could also be a coordinated design approach for the future.



Local supply approach: Each field is supplied from a dedicated electricity generation source (offshore wind, geothermal or other fueled power plants, etc). A local supply approach does not require a connection to shore (or hubs) and can thus be an independent alternative. However, both the coordinated and individual design approach can be combined with a local supply option.



Important note: Several of the other decarbonisation measures studied in this report are in some way a form of electrification: gas-fired power plants offshore with CCS supplying power to nearby platforms (with or without connection to shore), geothermal power plants for electrification, etc. However, when looking at electrification options specifically in this report, we are talking about either power-from-shore concepts through an individual or coordinated design approach, or dedicated local supply from offshore wind. The other electrification options are covered separately.

Power-from-shore

Overview of options

Various options for electrification with power from shore are promising solutions with the highest GHG reduction potential, high technology maturity level and abundant synergy with the booming offshore wind industry. The preferred network design solution depends on several factors, such as distance from shore and available weight and space on the platform. Although the individual approach is the most common today and least complex design, a coordinated approach has several key benefits and the potential to facilitate a gradual build-out of a meshed offshore grid in the future.

Short description

Below, we provide a short description of the two main network design approaches for power from shore solutions. Both designs rely on (i) the capacity of the interconnector cable from the platform (or hub) to shore and (ii) the hosting capacity of the point of interconnection to the onshore grid.

Individual: Each platform is connected to the onshore grid via a dedicated radial connection, tailored to each platform. Most of the existing power-from-shore projects are examples of this approach. The connections to shore will be a choice between AC and DC, dependent on the distance to shore and power need (see fact box).

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 several radial connections, in some regions connected to the same point onshore.

The individual approach offers simplicity in design and requires less coordination but can result in an overall sub-optimal network design and higher costs to ensure reliability of supply. If a DC connection to shore is needed, a separate hub for DC equipment or subsea equipment might be needed due to weight and space limitations on the platforms.

Coordinated: Multiple platforms are connected to one offshore hub (shared substation) before being further connected to the onshore grid through a radial connection. Johan Sverdrup (phase 2) is one example of this type of solution. The platforms could potentially be connected to other offshore hubs, energy islands, large wind farms, etc. The connections to shore will typically be DC while the local offshore connectors will be AC or DC depending on distance or 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 involve into a meshed offshore network and integrate with the offshore grid in the North Sea for offshore wind integration.

This design balances a minimized cable landfall footprint with the potential risks of limited redundancy and associated impacts to reliability. Although a more complex design requiring a high degree of coordination between stakeholders, significant economics of scale and a more optimal network design overall can be achieved.

AC or DC connection?

HVAC technology is normally used when the distance to shore is less than 200 km.

\+ Mature technology
\+ Lower footprint on platform for associated equipment
\- Higher losses, especially for long distances
\- Power rating limited by cable rating (< 200 MW per project)
\- Normally requires complicated reactive compensation onshore (SVC or STATCOM in addition to shunt reactors)
\- Needs frequency converters to supply 60 Hz platforms

HVDC is largely used for distances over 200 km.

\+ Lower losses
\+ 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 for associated equipment (HVDC converters)

Power-from-shore
Views on scope and scaling

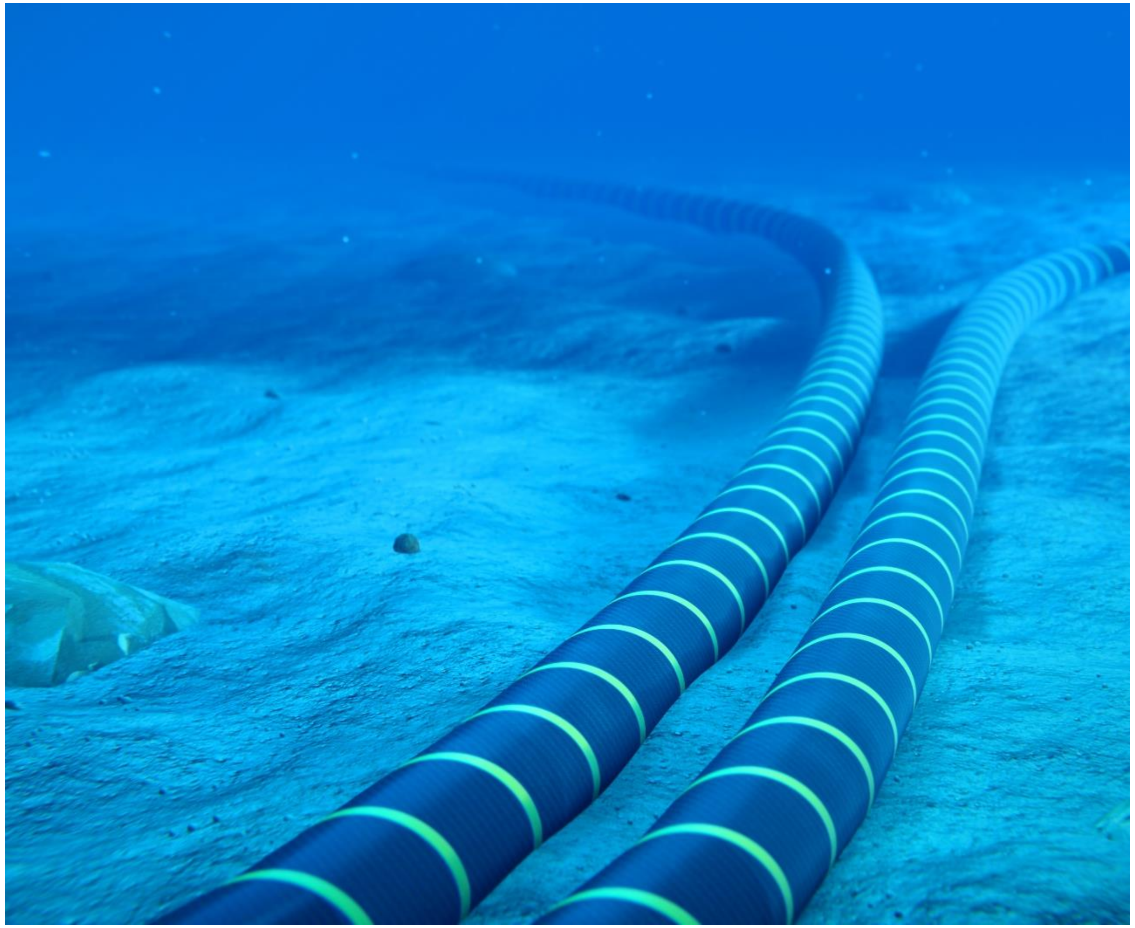


Illustration: Shutterstock/Vismar UK

Application scope and scaling potential

Application scope

- Electricity (from shore, offshore wind or power hub) can replace 100 percent 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 design approach and related equipment. TRL 6/7 for coordinated built-out when supplied from onshore grid.

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

Accelerating developments

1. Sector-coupling synergy with offshore wind
2. Dynamic cables and turret/high voltage slip ring for the connection of floating platforms
3. Subsea equipment and long-distance HVAC
4. Multivendor inter-operability of HVDC systems

DNV

Power-from-shore

Views on GHG emission reduction potential and major challenges and opportunities

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 percent of total scope 1 emissions.

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

Realistic reduction potential
As seen on page 31, a partial electrification could potentially reduce scope 1 emissions by 40 percent from todays levels. 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 for installations far from shore
- Frequency regime (50 or 60Hz) and the need for frequency converters
- Electrifying direct-driven turbines and heat demand (full electrification) more challenging and costly than partial electrification, increasing complexity of reducing remaining emissions through electrification.
- 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. Especially for full electrification, the downtime can be significant.
- Availability of onshore capacity and high power prices.
- Supply chain risk (limited qualified suppliers for HVDC converters and submarine power cables).

<u>Individual vs. coordinated:</u>

- 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). Combining a coordinated approach with offshore wind and connection to shore can ensure power supplied to shore during surplus hours which could help relieve the pressure on the onshore grid.
- 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.

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

Local supply from offshore wind
Overview of options

Offshore wind is at an applicable level of maturity and can be used to reduce the use of gas-fired turbines on the NCS. Norway has excellent offshore wind resources compared to onshore, however most water depths are above 60 meters which calls for floating wind as the main solution. Developing offshore wind to serve the NCS could reduce the need for new power onshore with limited effect on power prices and could potentially serve the onshore grid in the future.

Short description
Local supply design: Dedicated local power supply to each field (or several fields). A local supply solution does not require a connection to shore or other hubs and can thus be an independent alternative. This would reduce the need for new power onshore. However, both the coordinated design and individual design with power-from-shore can be combined with local supply – both to ensure security of supply (N-1) for the platforms as well as provide power to shore during hours of surplus energy generation. The local supply design is potentially attractive if there is significant distance to shore or other energy hubs. The complexity and decision-making process depend on each case. Here we focus on local supply from offshore wind. However, the power generation can come from other sources such as gas-fired power hubs, geothermal power plants, etc. These options are covered separately. **Offshore wind:** Offshore wind can be either bottom fixed or floating, however the water depth on the NCS suggests floating solutions are largely required. 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 therefore be implemented in combination with storage and/or other power sources. Bottom fixed wind is fully commercial with over 28 GW by 2021 installed in Europe (see figure) but still more expensive than 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 in order to reduce costs.

Offshore wind in Europe (2021)

All figures on the map are in MW

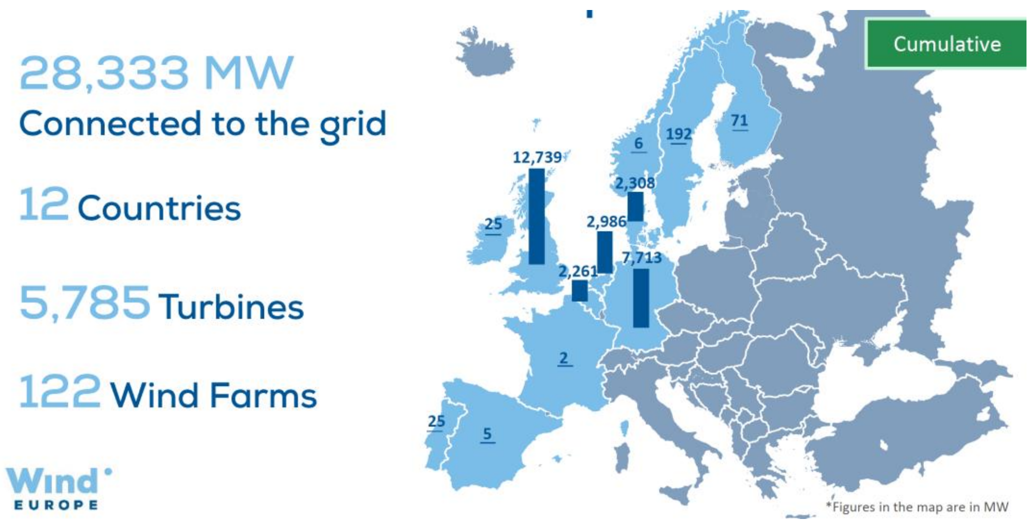


Illustration: Wind Europe, Offshore wind energy 2021 statistics

Local supply from offshore wind

Views on scope and scaling

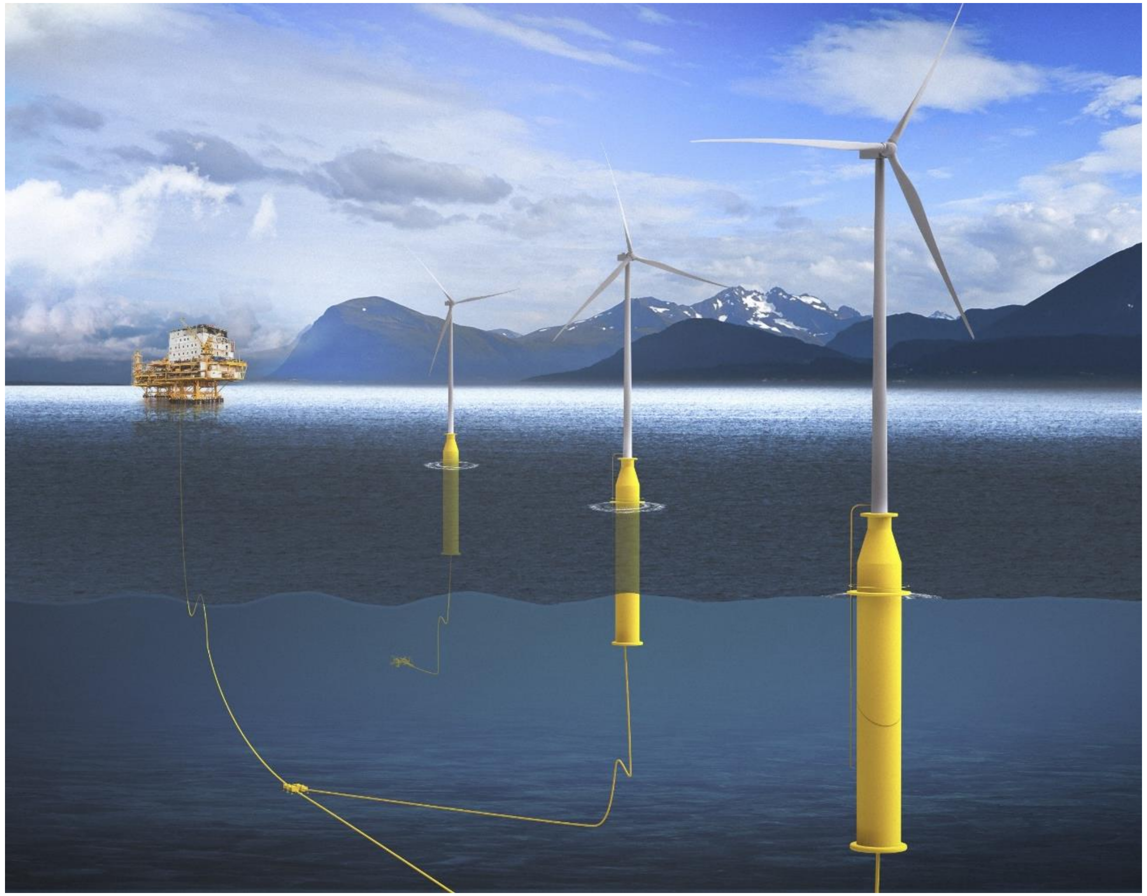


Illustration: DNV WIN WIN Joint Industry Project

Application scope and scaling potential
Application scope Offshore wind can replace or reduce the use of gas turbines for electrical purposes as well as for water injection.
Scaling potential and timeline Short term (2022-2030): Within 2030 the scaling will mainly be limited by the oil and gas industry's ability to attract the wind supply chain, due to fact that each individual project is much smaller than what the supply chain sees for utility scale wind parks. Bottom fixed is fully commercialized and will be a challenging market for the oil and gas industry as each location will require a unique design. Rapid development of floating wind will likely require a standardized and coordinated effort to attract attention from the supply chain. 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 [1].
Long term (2030 – 2050): Floating wind is expected to be commercialized within the long term perspective of 2030-2050 with the highest TRL level.
Accelerating developments Technical developments of dynamic cables and power integration with the platforms or a park.

[1] DNV, WIN WIN Joint Industry Project: Wind-Powered water injection, May 2019

Local supply from offshore wind

Views on GHG emission reduction potential and major challenges and opportunities

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.

Technical reduction potential
With a sufficient storage solution, it is technically possible to reduce the emissions from the gas turbines by 100 percent 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 percent 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 CO_2 emissions and 1,000 tonnes of NO_x emissions per year [2].

Main challenges and opportunities

Development and implementation obstacles

- **Security of supply:** 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, either locally on the platform or through connection to the onshore power grid.
- **Floating solutions:** As water depths mostly exceed 60 meters, floating solutions are required on the NCS. The offshore wind floater technology is ready, however, some technological gaps on dynamic cables, power integration, and floating offshore substations are yet to be closed.
- **Clarity in regulations and requirements:** 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. Moreover, clarity is needed for cross-over licence areas between O&G and offshore wind, especially for taxation rules and how a future connection to shore would impact this.
- **High costs:** One of the other main challenges is the cost. The solutions are availalbe, however, the cost of especially floating wind is not yet competitive in the power market. DNV predicts that the LCOE of floating offshore wind (globally) will be right below 60 USD/MWh in 2030 and around 43 USD/MWh in 2050. Bottom-fixed offshore wind is estimated at 41 USD/MWh in 2030 and 31 USD/MWh in 2050 [3]. The reduction in costs is expected to be driven by investments in large-scale projects.

Industry opportunities and synergies

- Europe has a bold offshore wind target of 60GW by 2030 and 300 GW by 2050 [4]. Development and upskilling of the Norwegian industry and supply chain for floating offshore wind will be highly valuable in the European market but the knowledge is fully transferable worldwide. The global market for floating wind is estimated at ~2500 bn NOK (2025-2050) [5].
- Utilizing existing O&G licenses for offshore wind farms could help accelerate the implementation of offshore wind on the NCS while waiting for dedicated offshore wind licenses.
- At the end of the lifetime of the platform the offshore wind can be scaled up and/or connected to a nearby offshore hub or energy island, to the power grid onshore, or with an export cable selling power to Europe to support their energy needs and decarbonisation goals. 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 when the O&G asset is decommissioned.
- The offshore wind units can also be used for production of alternative fuels such as hydrogen or as an offshore charging station.

[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)
[5] Rystad Energy, Flytende havvind for å dekarbonisere norsk sokkel: Hva skal til? (2020)

3.4

Electrification: Perspectives on how to accelerate impact

DNV

Electrification

Realistic reduction potential and key advantages

Power from shore: Electrification trough power from shore is the measure with the highest potential for GHG emission reductions towards 2030, with a total estimated potential of **4.5 million tonnes CO_2e emission reduction per year in 2030** [1]. This amounts to around 35 percent of today's emissions. However, a large portion of this potential comes from projects that are currently immature and categorised as highly uncertain. These are for example related to installations that are more difficult to electrify through power from shore, either due to longer distances, floating assets (FPSOs) or limited available weight and space topside. In order to be able to electrify these assets through power from shore measures, several obstacles need to be mitigated.

- According to a report by Rystad Energy, almost 50 percent of the total produced volume on the NCS (from 2020 to 2050) will be from FPSOs and installations with distances above 160 km from shore. In total, this amounts to around 45 percent of the total GHG emissions in the same time period [2].

Power from offshore wind: Electrification through local supply from offshore wind is estimated to have a potential of 0.4 million tonnes of CO_2e emission reductions per year in 2030 based on reported projects from the operators [1]. This is mainly from the Hywind Tampen project as well as some projects in earlier phases of development. However, the potential can be much higher, However, the potential can be much higher, especially in areas where electrification from shore is challenging. Offshore wind can also be combined with power from shore and be an intermediate solution until a cable from shore is in place.

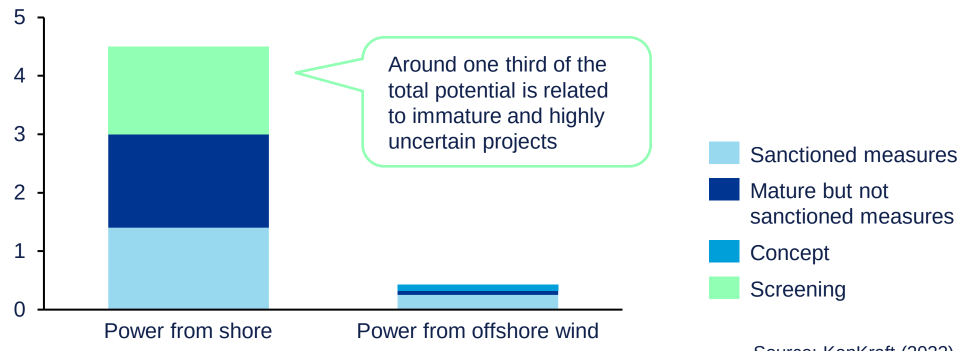
- Offshore wind combined with power from shore is especially attractive for existing electrification projects where a large part of the investments are already made. reduce OPEX from power purchases, limit total power losses through the transmission cables, while also give rise to fast-track medium-sized wind farms that could be important steppingstones to cost-efficient large-scale wind farms in the early 2030's.

Key advantages and opportunities

- Electrification increases the energy efficiency, resulting in less energy use overall. Moreover, the operational costs can be reduced due to lower cost of CO_2 tax and fuel. Electrification of offshore assets will also have the indirect benefit of reduced noise and thereby improved working environment offshore.
- The released natural gas can be exported to Europe and used in onshore gas power plants with higher efficiencies. This will both increase export revenues for Norway while at the same time helping Europe to become independent of Russian gas.
- A combination of building out an offshore grid with power form shore and offshore wind farms to supply installations on the NCS has **several industrial opportunities**: developing and upskilling floating offshore wind industry and supply chain in Norway; when connected, ensuring security of supply to the installations and power supply to the onshore grid during surplus hours; facilitate a future meshed offshore grid that can connect to the planned North Sea offshore grid long-term; facilitate an offshore industry long-term when O&G assets are decommissioned (i.e. hydrogen production from offshore wind).

Expected potential of electrification measures

[million tonnes CO_2eq/yr abated in 2030]



Source: KonKraft (2022)

[1] KonKraft, Status report (2022)
[2] Rystad Energy, Flytende havvind for å dekarbonisere norsk sokkel: Hva skal til? (2020)

Electrification

Power from shore: Major obstacles and possible mitigations (1/2)

Cancellations or delays of planned electrification projects will make it difficult to reach the 2030 targets. As there are several obstacles related to electrification – both through power from shore as well as from offshore wind – it is important to focus on how to mitigate them. Below, we list some of the main identified obstacles for **power from shore projects**, with possible mitigations in order to accelerate development and implementation. Note that cost aspects are covered separately.

Main development and implementation obstacles

- **Weight and space limitations for DC equipment:** Depending on distance from shore, DC transformation might be needed. Around 21 percent of the energy demand on the NCS comes from platforms located more than 200 km from shore[1]. As this requires AC/DC conversion equipment located near or on the platform, this poses a challenge for electrification of brownfield assets with limited space and weight available. This also limits possibilities for future tie-ins of other fields.
- **Electrification of ship-shaped FPSOs not matured:** Due to the lack of HVDC turret, electrification of ship-shaped FPSOs tends to be complicated and expensive. Around 13 percent of energy demand on the NCS come from FPSOs [1].
- **Full electrification of brownfield assets is challenging:** Electrifying direct-driven equipment and heating demand requires extensive retrofitting, greatly increasing the cost of electrification with associated loss of revenue due to downtime.

Possible mitigations and how to accelerate development

Weight and space limitations for DC equipment

- Long-distance HVAC: The achievable distance by HVAC is approaching 160 km, however this often implies expensive onshore equipment, higher power losses and increased operation complexity. Industry consensus suggests longer distances need major technology break-through.
- Compact DC equipment: By the deployment of DC GIS (recently deployed by Siemens in Dolwin 6 project).
- Subsea equipment: Development of large subsea transformers helps to reduce the DC footprint on the platforms. A medium-sized unit (around 20 MVA) has been qualified by DNV.
- Coordinated build-out: For platforms located near one another but far from shore, a coordinated approach with a dedicated platform hosting the required DC equipment and supplying the platforms with AC voltage could be a viable solution. This is already verified with the Johan Sverdrup concept. The platform could be a new build or re-use of a decommissioned platform. In the longer term at the end of production life, the platforms could be re-used for new offshore industries supplied by the DC platform (which in turn could be connected to a meshed offshore grid to ensure security of supply and relieve the onshore grid). Note that this will require cooperation and coordination between operators and license partners.

Electrification of ship-shaped FPSOs: Currently industry relies on a separate DC platform and AC turret to electrify a ship-shaped FPSO located far from shore, developing and qualifying DC turret will be necessary for the cost-effective electrification of such a FPSO. Alternatively, if the FPSO is located near other O&G platform or FPSOs, a coordinated build-out would be preferrable and DC turret will not be required in such case. Such challenges can be avoided with circular FPSOs.

Full electrification

- Compact electrical heaters: Using modern heat pumps, the size and efficiency of heat generation on the installation can be improved.
- Higher cost of alternative: The main obstacle to a full electrification is the associated downtime and loss in revenue, which could be substantial. As such, the alternative (doing nothing) needs to come at a greater cost. This could, for example, be in the form of higher CO_2 taxes or punitive measures if emission reduction targets are not met in time.

[1] Rystad Energy, Technologies to improve NCS competitiveness (2019)

Electrification

Power from shore: Major obstacles and possible mitigations (2/2)

Main development and implementation obstacles

- **Access to sufficient power from shore:** With today's sanctioned and planned electrification measures, the power demand for the petroleum sector is expected to double to around 18-20 TWh in 2030 [1] and the power surplus is decreasing. To ensure competitive prices in the Norwegian power market, the production capacity needs to be increased. Moreover, uncertainty in policy support could delay investments.
- **Long lead times and supply chain constraints:** Currently limited qualified suppliers for HVDC converters and submarine power cables. Moreover, long lead times could be an issue. Although the lead times varies depending on the case, Statnett currently experience lead times of 4-6 years for increasing transformer capacity, 5-10 years for a new substation or 7-12 years for a new power line [2].
- **Coordinated vs. individual build-out:** An individual build-out (several radial connections) will likely result in a sub-optimal network design and require more resources and higher overall costs. On the other hand, the solution is more mature. For the coordinated approach it can be difficult to find the appropriate cooperation structures among operators and license partners as remaining lifespan and needs differ between installations.

Possible mitigations and how to accelerate development

Access to sufficient power from shore

- Speeding up decision-making processes: The current slow speed of building out the grid and developing new power plants is a major obstacle. To ensure sufficient speed, license and application processes should be reviewed and the capacity of proceedings should be strengthened.
    - Go-to-zones: The EU has proposed to establish "go-to-zones" for new solar and wind plants where the processing time should range from six months (for smaller power plants) to a maximum of one year (for larger power plants). Outside the "go-to-zones", the license application needs to be processed within two years with strict requirements on maximum development speed should the license be approved. As part of the EEA, Norway might be covered by this fast track permitting plan.
- Predictable and long-term policies: Predictable and long-term policy support for electrification of O&G assets through power from shore measures is essential in reducing the uncertainty of developing long-term and complex electrification projects.
- National electrification strategy: KonKraft recommends creating an overall national electrification strategy with associated grid development plans and clear prioritisations to ensure sufficient support for power from shore measures [1].

Long lead times and supply chain constraints

- Speeding up lead time of grid investments: See point above on speeding up decision-making processes.
- Standardising equipment: By standardising the power and voltage rating of key components, the electrification can benefit from the large supply chain build-up triggered by the offshore wind industry.
- Innovative tendering/contracting strategies (e.g., partnership with key OEMs) could help mitigate supply chain constraints.

Coordinated vs. individual build-out

- Installations far from shore should aim for coordinated build-out: Where DC supply is required, the platforms located in the same areas should aim for a coordinated build-out to reduce costs (see previous page).
- Dialogue and cooperation is key: A coordinated build-out can lay the foundation for a future meshed offshore grid that increases redundancy an may help reduce onshore regional bottlenecks. Need to ensure good dialogue and cooperation between operators and license partners.

[1] KonKraft, Status report (2022)
[2] Statnett, How to get increased capacity: For grid operators

Electrification

Offshore wind: Major obstacles and possible mitigations

Below we list some of the main identified obstacles for electrification through **local supply from offshore wind**, with possible mitigations in order to accelerate development and implementation. Note that cost aspects are covered separately.

Main development and implementation obstacles

- **Security of supply:** The biggest issue with local supply from offshore wind is the variable power delivery. To ensure security of supply, a back-up solution - either from fossil-fuelled turbines, storage solutions or power from shore - is required.
- **Dynamic export cables:** Dynamic inter-array cables are commercially available and needed between the units and to the substation. However, the dynamic export cable is required from the floating substations and to shore/endpoint, and there is not any high voltage dynamic cables available yet.
- **Framework conditions, supporting mechanisms and regulations need to be in place:** Current framework conditions and supporting mechanisms are likely not sufficient in ensuring Norway can meet its goal of 30 GW offshore wind. Moreover, permitting processes and regulations are still unclear and under development.
- **Supply chain constraints:** The wind industry will be competing against O&G industry for vessels and port capacity. Another challenge is to get competitive prices on manufacturing and T&I for small scale projects. With projects being developed simultaneously the delivery of all components - floater, turbine, mooring and cable - and the access of competent workers, vessels and ports, may be challenges in some areas.

Possible mitigations and how to accelerate development

Security of supply: To ensure sustainable back-up solutions, work should be done on integrating e.g. battery or hydrogen storage, or a combination. Currently, there are no commercial or demonstration projects combining floating wind and back-up solutions known to DNV. Continued R&D and demonstration work in this area is needed.

Dynamic cables: There are a few examples of dynamic AC cables for voltages >66 kV AC being installed, however with limited operational experience. To DNVs knowledge, dynamic DC cables (relevant for distances above around 110 km) are not qualified or in use in any projects. Continued R&D and technology qualification work in this area is needed.

Floating offshore substation: Might not be necessary for O&G platforms due to few units and short distances and could consider bottom fixed substation.

Framework conditions, supporting mechanisms and regulations need to be in place

- Sufficient framework and supporting mechanisms: In order to close the price gap for floating offshore wind and ensure sufficient scaling and speed in developments, frameworks and supporting mechanism need to be established. Examples could be contracts for difference, as seen in the UK.
- Clarity in regulations are needed: Robust regulations for offshore wind development and clarity in basis for competition need to be in place to support strong deployment and provide long-term investment signals. Clarity is also needed for cross-over license areas between O&G and offshore wind, and how future connection to shore would impact this. Utilizing existing O&G licenses for offshore wind farms could help accelerate the implementation of offshore wind on the NCS while waiting for dedicated offshore wind licenses
- Speeding up decision-making processes to increase build-out: The current slow speed of developing new offshore wind is a major obstacle. To ensure sufficient speed, license and application processes should be reviewed, the capacity of proceedings should be strengthened, and new license areas should be opened. EU is considering establishing go-to-zones that could increase the speed (see previous page).
    - Although the target of 30 GW offshore wind is a step in the right direction, it is still not clear how the target will be reached. Developing a national roadmap with supporting framework could provide clarity and help acceleration.

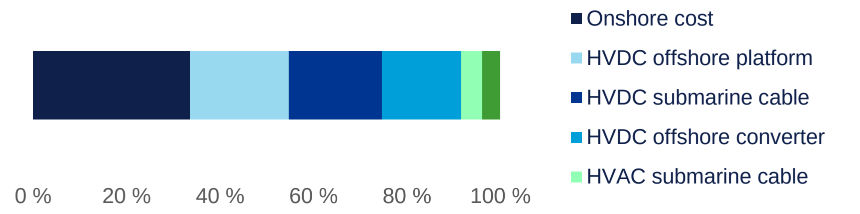
Supply chain constraints: Develop local supply chains and coordinate developments across regions and industries. Predictability is a key factor to remove the risk of investment in the supply chain for the industry, as seen in the point above on “Framework conditions”.

Electrification

Power from shore: Main cost drivers and cost effects

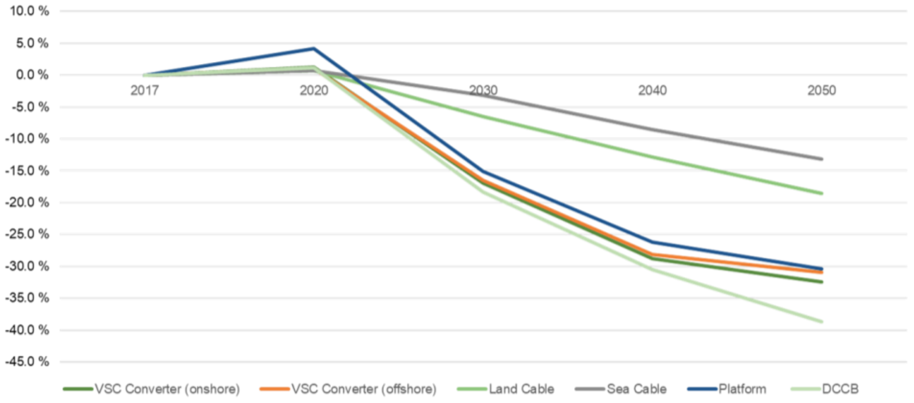
- **CAPEX:** The major CAPEX elements related to offshore HVDC supply from shore is shown in the top figure, given as cost breakdowns on the different components. The main cost items for the offshore supply is split around equally between the offshore platform, the submarine cable and the offshore converter. However, the cost split can vary depending on the given case, especially if submarine equipment is needed. Note that the onshore cost also represent a high share of the CAPEX, and can be greater if investments in grid capacity onshore is needed.
  - When looking at awarded contracts for offshore HVDC transmission projects in Germany and the UK, the **CAPEX varies between 0.9 and 1.3 MUSD/MW**. The costs are for project sizes in the range of **900 – 1200 MW and 130 – 170 km distance**. Note that this is for offshore wind projects and does not include cost of retrofitting O&G assets. For smaller-sized projects, the relative CAPEX will increase due to less economy of scale.
  - The major cost elements are related to manufacturing, transport and installation, and R&D cost as well as project management. Moreover, as HVDC offshore supply is still an emerging market, there is a high profit margin and risk premium on the projects. The main cost drivers are labour and engineering, raw material such as metal, semiconductors, etc., and the energy cost for fuel and electricity.
  - The total costs for offshore HVDC transmission are expected to reduce over time. The bottom graph includes the cost reduction potential towards 2050. As can be seen from the figure the greatest cost reduction potential is related to the direct current circuit breaker (DCCB), voltage source converter (VSC) onshore and offshore, and the platform itself where the reduction potentials are in the range of 15-25 percent in 2030 (30-40 percent in 2050).
- **OPEX:** On a high level, the OPEX (excluding power price) for offshore HVDC transmission is estimated to lie in the range of 2-3 percent of CAPEX per year. Over the lifetime, this amounts to around 20-30 percent of the total CAPEX. In addition, the power price will add to the OPEX for the O&G asset.
- **Abatement costs:** The abatement costs vary greatly between projects, depending on, amongst others, downtime needed for retrofitting, available space and weight on the installations, distance to shore, and whether there is a need for investment in grid capacity onshore. The «Kraft fra land» report from 2020 calculated the abatement cost of several sanctioned and mature electrifiaction projects on the NCS, showing a range from **600 to 2000 NOK/tonne CO_2**. For the more immature and complex projects, abatement costs up to 8000 NOK/tonne CO_2 could be seen [1].
  - Equinor estimated the electrification of Johan Castberg with HVDC from shore to have abatement cost between 3900-4600 NOK/tonne CO2 (real 2016). This included a separate DC to AC converter facility and significant upgrades to the onshore grid, showcasing how available capacity in the onshore grid can pose a major cost challenge [2].

Cost breakdown of CAPEX for HVDC projects



Source: DNV, average cost breakdown of awarded contracts globally

Cost reduction potential of HVDC equipment towards 2050



Source: DNV estimates

[1] NPD, Kraft fra land (2020)
[2] Rystad Energy, Technologies to improve NCS competitiveness (2019)

Electrification

Offshore wind: Main cost drivers and cost effects

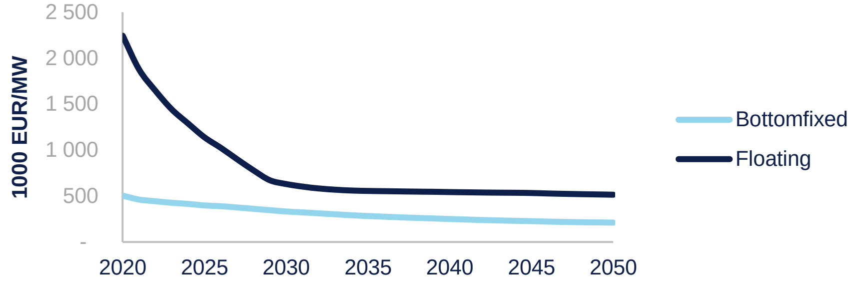
- When floating wind matures, the **cost reduction** will be driven by larger turbines, optimization and innovations for floaters and mooring systems, standardization, supply chain development and reduced risk.

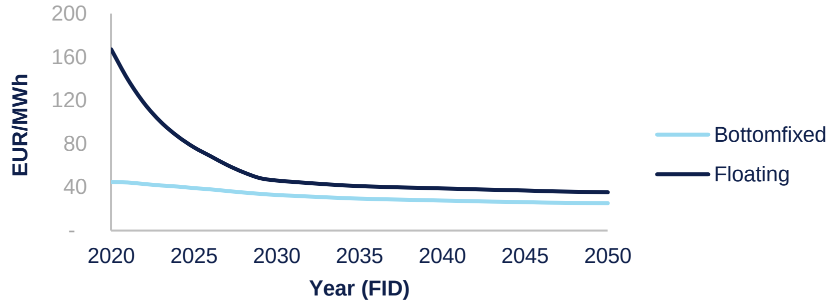
- **CAPEX** is mainly driven by the floater, mooring and turbine cost. The turbines used for floating wind are typically the same turbines as used for bottom fixed with modifications in the control system and potentially strengthening of the tower. For the short term we foresee a significant cost difference due to the risk level in the floating industry and bottom fixed benefitting from economy of scale. Floating wind is a new industry with only two floating wind farms installed. This impacts the level of experience and available supply chain. There are also limited economy of scale effects with the current windfarm sizes (3-11 units). In addition, floating wind structures typically require more material than bottom fixed. While the steel mass for a structure used for a bottom fixed windfarm with 8 MW turbines could be typically around 1000 tones, a floating wind structure could require more than 2000 tones of steel for the same turbine. Further, more material is needed for anchors and mooring system. The structures themselves are in addition more complex to design and fabricate, especially compared with monopiles.

- **OPEX** for floating wind is expected to be reduced by 87% (149 KEUR/MW to 19 KEUR/MW) in the next 30 years. Today OPEX is ~5 times higher than bottom fixed, but the cost difference is expected to be reduced to ~10% by 2035. OPEX for floating wind differs from bottom fixed mainly due to additional inspection and maintenance of the more complex foundation and station keeping system, but also major component replacement, which typically requires the floaters to be towed to shore. In the short term OPEX will be significantly higher driven by the small windfarm sizes and as well a risk premium for the novel industry. However, when the floating wind industry matures, it is assumed that OPEX for floating wind turbines will follow the same cost trajectory curve as for bottom fixed wind. A small cost mark-up is assumed due to the foundations requiring more inspection and maintenance and because floating wind farms are assumed to be further away from shore and in a harsher environment than bottom fixed wind.

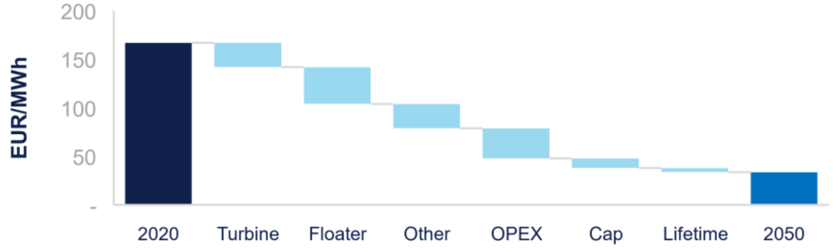
- **The Levelized Cost Of Energy (LCOE)** for floating wind is expected to be reduced by 80% in the next 30 years resulting in a global average of **35 EUR/MWh** and total investment cost **of 1.7MEUR/MW in 2050**. While the LCOE for floating wind on average is 37% higher than bottom fixed in 2050, deployments will be needed to meet the global demand in offshore wind and bottom fixed cost is expected be very low at around 26 EUR/MWh.

Developments in cost of installed foundation (top) and LCOE (bottom)





Cost reduction potential for floating wind



Source: DNV ETO 2021

Norwegian technologies for the future
Odfjell Oceanwind


Illustration: Odfjell Oceanwind

1. **Electrifying O&G without power from shore**
2. **Reduce emissions from 2024**
3. **Kick-starting an export industry based on floating wind**

- Odfjell Oceanwind has launched a MOWU (Mobile Offshore Wind Unit) to support the O&G industry. The unit is designed for harsh environment and simple installation and removal to support the company's rental business philosophy .
- The company offers a hybrid micro-grid solution, claiming to reduce CO2 emission with up to 70% for comparable conventional power generated from fossil fuel.
- Odfjell Oceanwind is a part of the Odfjell companies and can take advantage of the legacy and offshore experience from Odfjell Drilling and Odfjell Technology.

3.5

Gas-fired power hubs with CCS: Background

Gas-fired power hubs with CCS, serving the NCS

Overview of options

Norway is leading the way in developing an infrastructure for carbon capture and storage (CCS), which could be utilised for reducing emissions on the NCS. A stand-alone gas-fired power hub with CCS has the potential of reducing emissions through electrification while at the same time not requiring capacity from the onshore power grid. The power hub could be located onshore or offshore, both with their own advantages and disadvantages. The focus here is the offshore solution. The GHG emission reduction potential is somewhat less than for direct electrification due to the capture rate of the carbon capture facility not reaching 100 percent.

Short description

A gas-fired power plant with CCS provides electricity through running gas turbines while capturing and storing the CO_2. The plant could be located both onshore or offshore, which will largely be a matter of cost optimization (see fact box). In this sub-chapter, the focus is on the offshore solution.

- No installations offshore currently exist. However, the equipment can be based on mature technologies (e.g., amine-based solvents for CO_2 capture).
- The power plant could be based on a combined cycle configuration, including multiple gas turbines and steam turbines, utilizing the gas turbine exhaust waste heat in Heat Recovery Steam Generators [1].
- The location of the power hub should be an optimization between closeness to the installations to be electrified and the CCS value chain – both in terms of cost and technical feasibility.

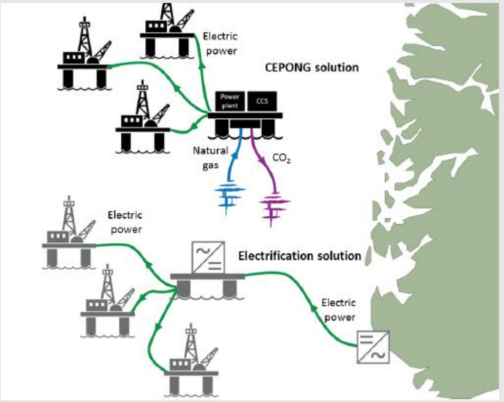


Illustration: Clean Electricity Production from Offshore Natural Gas (CEPONG) concept

	Offshore power hub	Onshore power hub
Efficiency	• Smaller units with lower efficiency • Lower transmission losses	• Possibility for larger turbines with higher efficiencies • Longer distances with higher transmission losses
Cost	• Closer to point of consumption, limiting cost and complexity of electrical infrastructure. • (Likely) closer to infrastructure for importing natural gas and exporting and storing CO_2. • LCOE from offshore hub with CCS has been estimated to be 70 percent higher compared to an onshore plant with CCS [1]. The exact number will depend on the distances, available infrastructure, fuel prices, etc.	• Lower CAPEX and OPEX for the power plant and CC facility. • Higher CAPEX and OPEX for electrical distribution grid (especially if HVDC is needed). • The modifications and downtime needed on the importing platform will most likely be larger. • Potentially higher infrastructure cost of importing natural gas and exporting and storing CO_2.
Maturity	• Mature technologies, but novel concept • CCS not implemented for flue gases offshore to date, technology qualification might be needed.	• Mature technologies • CCS not implemented on gas-fired power stations to date, first plant planned to be in operation in 2025.
Scalability	• Concept can be duplicated and implemented in several locations, and size can be adapted depending on the power demand of the platforms	• Will most likely be a larger unit.
Location	• Potentially easier to locate ("out of sight, out of mind") • Can more easily be relocated for future use (floating).	• Finding new sites onshore is potentially difficult due to public opposition but could be located close to industrial sights with existing natural gas and CO_2 infrastructure.
Onshore grid impact	• Stand-alone solution and independent of onshore grid capacity. • Can potentially be connected to shore to supply power to (and balance) the onshore grid	• Can supply power to (and balance) the onshore grid.

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

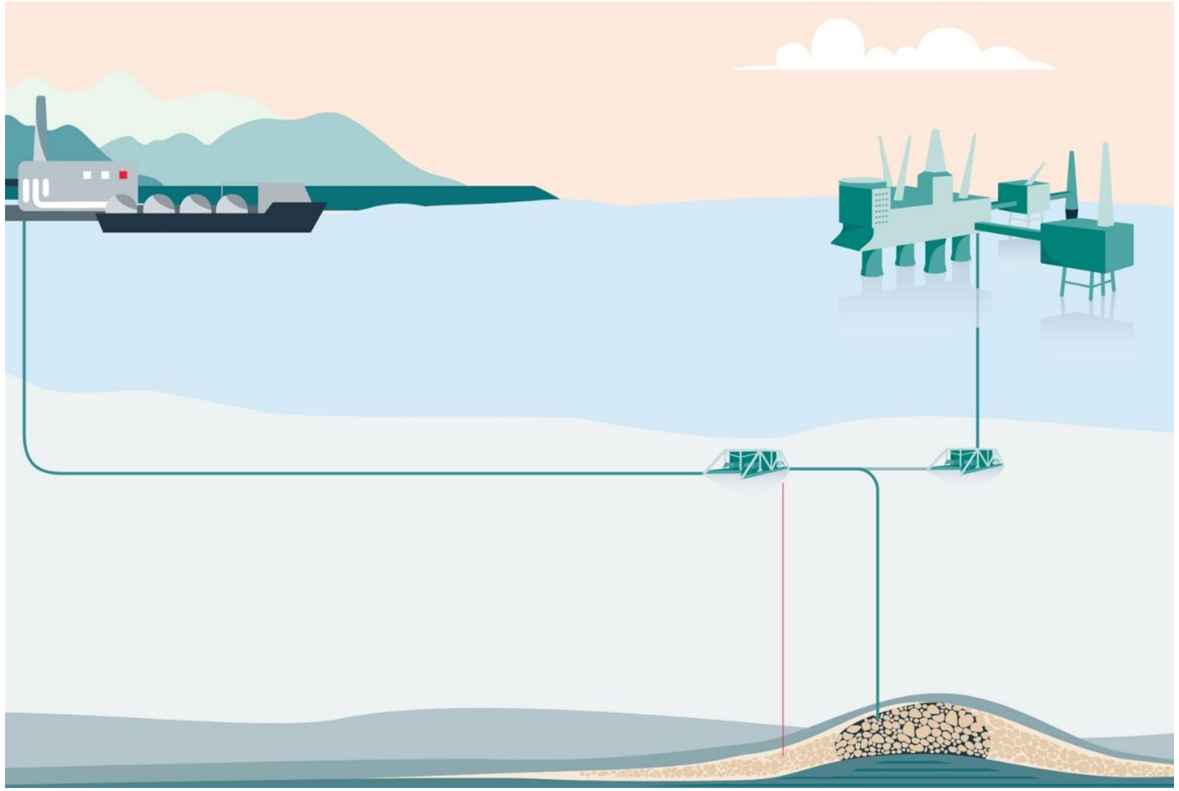
Gas-fired power hubs with CCS, serving the NCS

Views on scope and scaling

Application scope and scaling potential
Application scope A power hub offshore should be assessed in relation to electrification from shore in terms of application, i.e. 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 percent (based on capture ratio 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) • CO_2 transport TRL 7 (dependent on technology development)
Accelerating developments • Develop accessible CO_2 storage infrastructure – including CO_2 shipping or pipeline infrastructure • Explore models to connect with existing CO_2 infrastructure and storage projects such as Northern Lights (NO) and/or others.

Illustrative concept of the Northern Lights project



Illustrations: Northern Lights

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

Gas-fired power hubs with CCS, serving the NCS

Views on GHG emission reduction potential and major challenges and opportunities

GHG emission reduction potential

Target emission sources
Replacing gas turbines on O&G platforms. In 2019, gas turbines offshore made up 68 percent of total upstream and midstream CO_2 emissions.

Technical reduction potential
Based on current technology one could assume a capture rate between 80-90 percent 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 successful 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 de-risking 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 de-risk 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
- 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]
- Continue opening up more storage locations for potential cross border CO_2 storage. The Ministry of Petroleum and Energy has already opened up and assigned two additional license areas for CO_2 storage on the NCS.
- Further cement Norway's leading edge as a global leader in CCS activities and commercial CCS value chains, providing future revenue by handling third party CO_2 emissions. Permanent storage of CO_2 will be even more important as we move towards decarbonising hard-to-abate sectors as well as scope 3 emissions.
- Develop the Norwegian CCS supply chain.

[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

Gas-fired power hubs with CCS
Main risk factors of offshore CO_2 storage

There are two main storage reservoir types for CO_2 storage offshore: deep saline aquifers and depleted fields. Although the preferred choice is case specific, it is important to know about the main risk factors and differences.

Risk factor	Deep saline aquifers	Depleted fields
Containment • Well • Faults and seal	• Typically fewer legacy wells – primary anthropogenic leakage path • Faults and seals not geomechanically weakened through production, but depending on the distance from O&G fields, are untested	• Typically higher density of legacy wells, as the field has been explored developed and produced • 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 aquifers
Injectivity	• Greater uncertainty due to lack of data, cannot be de-risked 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 fracture 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 as no simultaneous operations occur if an aquifer is developed from a greenfield platform (only fluid on the platform is CO_2). • Potentially higher de-risking 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.

DNV

Image source: DNV/DGS AS

3.6

Gas-fired power hubs with CCS: Perspectives on how to accelerate impact

Gas-fired power hubs with CCS
Realistic reduction potential and key advantages

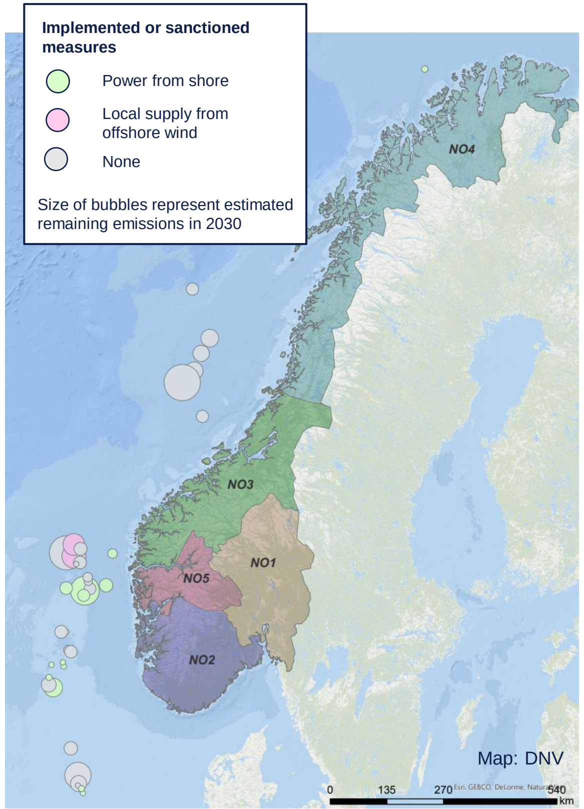
Offshore gas-fired power plants with CCS is currently not part of the reported measures from the operators, according to KonKraft. However, when looking at the map to the right, it is evident that there is a potential for reducing emissions on installations located close together and where a power hub solution could be a viable option compared to electrification with power from shore.

- North Western area: Three FPSOs and two platforms located between 150-200 km from shore, i.e. HVDC might be needed if selecting power from shore (especially difficult for FPSOs). With a hub solution, all installations could be located around 30-50 km from the hub area and supplied with AC power. The total emissions from the five installations in 2020 was 2,1 million tonnes CO_2e.
- Western area: Five platforms located between 150-200 km from shore, i.e. HVDC might be needed if selecting power from shore. For two of the platforms, local supply from offshore wind (Hywind Tampen) is in development, reducing emissions by around 35 percent. With a hub solution, all installations could be located around 20-30 km from the hub area and supplied with AC power. For the platforms with offshore wind supply, the hub could provide security of supply. The total emissions from the five installations in 2030 (including implemented or sanctioned emission reduction measures before 2030) was 2,2 million tonnes CO_2e.
- Southern area: Three platforms (not currently electrified through power from shore) located above 200 km from shore, i.e. HVDC would be needed if selecting power from shore. With a hub solution, all installations could be located around 20-30 km from the hub area and supplied with AC power. The total emissions from the three installations in 2020 was 0,9 million tonnes CO_2e.

In total, a power hub located in these three areas could reduce emissions by **4.5 million tonnes CO_2e per year in 2030*** (around 35 percent total reduction from 2020 levels), if all required infrastructure is in place. The following pages look at how to accelerate implementation by overcoming some of the major obstacles, as well as cost effects.

Key advantages and opportunities

- An offshore power hub is a stand-alone solution independent of power from shore. As such, it can help provide electrical power to installations in areas with limited onshore infrastructure or long distances to shore. Providing AC power to nearby platforms limits the retrofitting and associated downtime compared to HVDC supply from shore. In the long term, the power hub could be connected to shore to supply additional power and balancing capabilities to the onshore grid.
- Electrification of nearby platforms as well as more efficient turbines running the power plant on the hub increases the energy efficiency, resulting in less energy (and fuel) use overall. The operational costs can be reduced due to lower cost of CO_2 tax and fuel. Moreover, the released natural gas can be exported to Europe to increase export revenues for Norway while at the same time helping Europe to become independent of Russian gas..
- A floating power hub solution could be re-located for future use, either to supply other O&G assets or new offshore industry (such as deep-sea mining or replacing the power plant with methane reformers to produce hydrogen with CCS). In the long term, the gas turbines could be run on low-carbon fuels or replaced with fuel cells if natural gas supply is diminished.
- The solution could help further develop the Norwegian CCS supply chain, cementing Norway as a global leader in CCS activities and commercial CCS value chains. This can help facilitate future revenue in handling third party CO_2 emissions on the NCS.



Map: DNV

*Assuming full electrification and 87 percent of emissions from offshore installations coming from gas turbines (SSB, 2019)

Gas-fired power hubs with CCS

Major obstacles and possible mitigations

As there are several obstacles related to offshore power hub projects it is important to focus on how to mitigate them. Below, we list some of the main identified obstacles for **offshore power hub projects**, with possible mitigations in order to accelerate development and implementation. Note that cost aspects are covered separately.

Main development and implementation obstacles

- **Novel concept:** An offshore power hub with CCS has not been built and CO_2 capture has not been implemented for capturing CO_2 from flue gases from a gas fired turbine offshore. The same statement is valid for carbon from gas fired power generation in general, but there are planned projects.
- **Long lead time**: An offshore power hub requires a new floater and new infrastructure which takes time to develop. Blå Strøm has estimated the lead time to 3-4 years.
- **Access to qualified storage site**: 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. A commercial value chain for CCS is not yet fully in place.
- **Weight and space limitations:** The platform importing power from the power hub will require retrofitting to receive and distribute the imported power. Might pose a problem for brownfield assets with limited space and weight available.
- **Full electrification of brownfield assets is challenging:** Electrifying direct-driven equipment and heating demand requires extensive retrofitting, greatly increasing the cost of electrification and potential loss of revenue due to downtime.
- **Many stakeholders:** A power hub requires many operators and stakeholders to agree on a solution and distribute cost and risk.

Possible mitigations and how to to accelerate development

Novel concept: There are developed concepts for offshore power hubs with carbon capture, including concepts by Blå Strøm, Aker Solutions and Sintef. The first gas power plants with CCS estimated to be in operation in 2025 (Global CCS Institute, 2021). Flue gas gases from gas fired turbines has fewer impurities compared to other flue gas streams, reducing the need for pre-treatment. At the same time, the CO_2 concentration is lower requiring bigger equipment due to smaller driving force. Use qualified equipment as far as possible in order to reduce risk and uncertainty.

Long lead time: Long lead time means that studies to evaluate potential locations need to be started as soon as possible to be able to contribute to the 2030 goals. Reuse of existing platform/floater can lower the lead time.

Access to qualified storage site: In order to ensure sufficient storage is available, suitable storage sites could be developed in parallel and more license for CO_2 storage could be allocated.

- KonKraft suggest establishing concrete targets for how much CO_2 should be stored on the NCS to ensure CCS becomes a commercial industry. Moreover, they encourage Norwegian authorities to help in simplifying regulations related to transport and storage of CO_2, as these are currently comprehensive and complex.

Full electrification of brownfield assets is challenging: Aker Carbon Capture has suggested that if the power hub is located next to an installation the flue gases from direct drive gas turbines can be captured on the power hub as well. This option will only be available for one of the installations importing power from the power hub.

Many stakeholders: Early dialogue and cooperation is key and assigning a pilot area to test the concept can be started immediately. For the Blå Strøm offshore power hub concept, they can act as an external party facilitating collaboration across license owners, and the interface between Blå Strøm and the operator(s) can be tailored to each case which helps bring down risk and complexity.

- KonKraft suggest adapting the public support system to facilitate maturing of solutions that ensure sufficient scale, learning effects and cost reductions for CO_2 transport and storage.

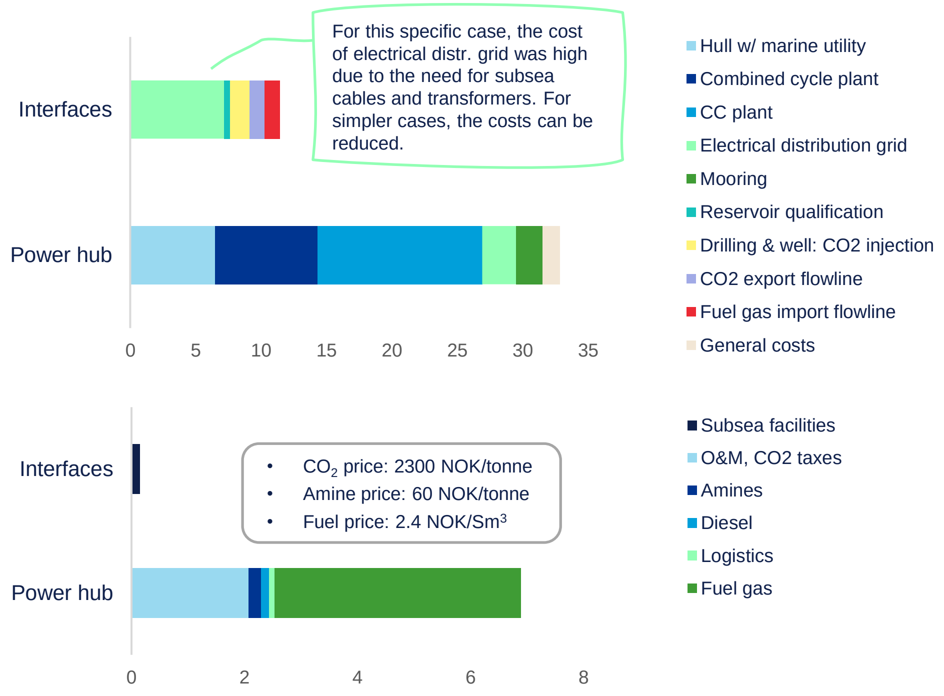
Gas-fired power hubs with CCS
Main cost drivers and cost effects

- For an offshore power hub with CCS, the CAPEX occurs on three levels: the power hub, the required interfaces, and the modifications (retrofitting) on the importing platform. The OPEX is mainly driven by the cost of fuel for running the gas turbines.

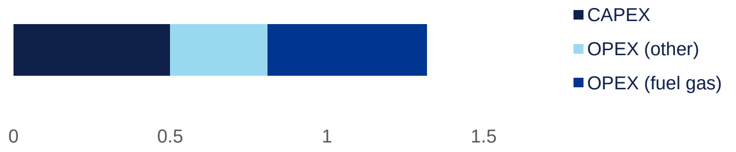
- The **Blå Strøm** consortium have done a case study on delivering 200 MW_e to nearby platforms from their floating power-hub concept. The power hub is a floating Sevan hull with a combined cycle power plant, a carbon capture (CC) plant including CO_2 treatment as well as the necessary electrical distribution grid. In addition, the case study includes the subsea electrical distribution grid for power supply to the platforms, the CO_2 export flowline and fuel gas import flowline, as well as necessary reservoir qualification and drilling. **The resulting CAPEX and OPEX per MWe and LCOE* are shown in the figures to the right.** The Blå Strøm concept is described in more detail on page 70.
  - The CC plant is by far the main cost driver for the CAPEX of the power hub. The CC plant uses mature technology with amine absorbers. These absorbers are around 28-32 meters tall and located in the hull. Ongoing developments with smaller and more modular systems as well as other capture technologies could lower the costs in the future.
  - The fuel price is the main cost driver for the OPEX. Depending on the development of the gas prices, the OPEX might increase drastically. However, considering the combined cycle power plant is more efficient then running traditional gas turbines on the platforms, the fuel savings can result in net lower OPEX for the operator. Moreover, the reduced cost of CO_2 tax will further contribute to net lower OPEX.
  - Note that the cost of modification on the importing platforms has not been included as this is extremely case dependent. However, this will likely be the same as for electrification from shore with AC cables.

- **Aker Solutions** have developed concepts together with international oil companies for offshore floaters with gas-fired power plants and CO_2 capture based on well-known LM 9000 gas turbines with an ISO rating of 75 MW. An example is a ship-shaped power barge with VLCC (Very Large Crude Carrier) hull size, which can accommodate a power generation system consisting of 8 x LM9000 gas turbines with corresponding post combustion capture systems and CO_2 re-injection. This system will provide a net power export capacity of 500 to 550 MW_e depending on the gas composition and corresponding requirement for treatment. The CAPEX of such a facility is estimated to be in the order of magnitude of 20 to 25 billion NOK (37 – 50 MNOK/MWe) which is in line with the estimates from Blå Strøm. Aker Solutions also has technologies for **subsea power hubs with direct CO_2 injection** which is described in more detail on page 71.

CAPEX in MNOK/MWe (top) and OPEX in MNOK/MWe/yr (bottom)



Levelized cost of energy (LCOE)
[NOK/kWh]



*Based on calculations by Blå Strøm with a CAPEX depreciation of 10 years.

Norwegian technologies for the future
Blå strøm

Short description

Blå Strøm is a consortium of companies in the Norwegian supplier industry, delivering a floating gas-fired power unit with CCS. The unit can be scaled to produce 100-500 MW electricity with a capture rate of approx. 90 percent.

For a given case, a 200 MW_e unit produces gross 230 MW_e (13 percent of produced power to the unit and CC facility), uses 1 MSm^3/d natural gas and captures 0,72 $MtCO_2$/yr.

Advantages

- Reduces emissions from offshore oil and gas operations. A 300 MW unit is estimated to save around 1,3 million tonnes CO_2 per year compared to running gas turbines on the platforms.
- Short lead time (3-4 years) with ability to reach the 2030 emission targets.
- Stable source of energy (compared to e.g. offshore wind).
- Independent of power-from-shore and releases gas for exports to Europe due to increased efficiency (both from electrification as well as running more efficient combined cycle turbines).
- Possibility of placing electrical equipment (frequency converters, transformers) on the floater, simplifying brownfield modifications.
- Blå Strøm can be an external party facilitating collaboration across license owners, and the interface between Blå Strøm and the operator(s) can be tailored to each case (e.g. Blå Strøm could own and operate the unit to deliver energy per kWh).
- The unit could connect to offshore wind and/or provide power to shore.

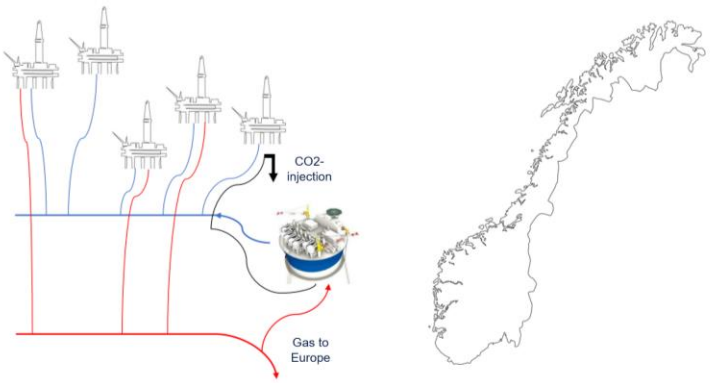
Maturity

Technology Readiness Level (TRL)

- Relies on mature and available technology for the floater (Sevan hull), electrical equipment, and a combined cycle power plant.
- Carbon capture using amine-technology as base case but technology neutral concept to support customer preferences and technology developments.
- To simplify brownfield modifications at platforms, subsea transformers may be selected, depending on each case.
- Carbon capture technology is matured from e.g. the technology center at Mongstad, and knowledge on storage is available from the application at the Sleipner field.

Commercial Readiness Level (CRL)

- Commercially ready. 3-4 years lead time from investment decision estimated for hub and related infrastructure.



Costs

Investment costs

A 200 MWe Blå Strøm hub was estimated to have an investment cost of around 6600 MNOK, with the largest cost drivers being the CC facility and the combined cycle power plant. The investment costs are largely linear with power production for units above 100 MWe.

The interface costs are highly case dependent, i.e., the electrical distribution grid to the customer and the CO_2 transport and storage solution. A given case of a 200 MWe power delivery to four platforms estimated an interface investment cost of 2300 MNOK, including reservoir qualification, drilling and well, subsea electrical distribution grid, as well as CO_2 export and fuel gas import flowline.

When the unit supplies several platforms, the relative placement of the unit is a minimization of three cost elements: electrical supply to the platforms (including most cost-effective modifications at the platforms given their weight and space limitations), infrastructure for CO_2 storage, and infrastructure for natural gas supply.

Levelized cost of energy (LCOE)

A general cost estimate on power delivered (LCOE) was calculated to be 80 NOK-øre/kWh, where:

- CAPEX = 50 NOK-øre/kWh
- OPEX = 30 NOK-øre/kWh, where the tax on emitted CO_2 constitutes around 8.5 NOK-øre/kWh

If the natural gas has an alternative value (e.g. exports), a price of 2.4 NOK/Sm^3 equals around 50 NOK-øre/kWh in increased LCOE.

Abatement costs

The abatement cost ranges between 1500 and above 2000 NOK/tonne CO_2, however this is highly case dependent.

All information is used with permission from the Blå Strøm consortium

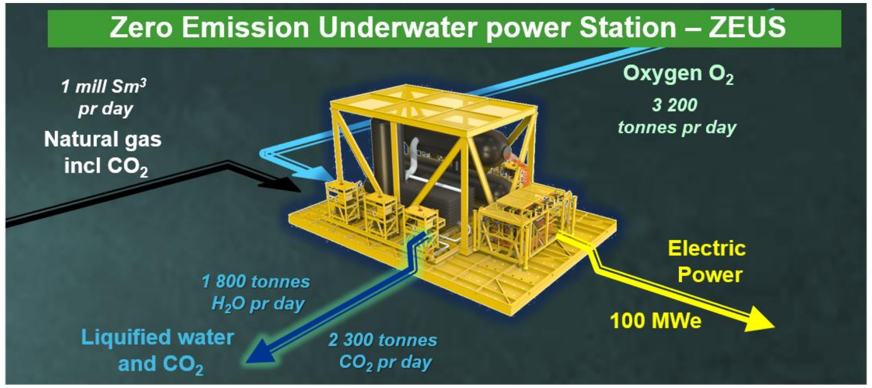
Norwegian technologies for the future
ZEUS: Zero Emission Underwater Power Station

Short description

ZEUS produces electrical power by burning natural gas and pure oxygen at the seabed, close to the production well(s). The oxygen is provided by an Air Separation Unit (ASU) placed offshore close to the power station and the combustion is done at elevated pressure coming from the wells. The resulting CO_2 is re-injected directly into the same reservoir or a nearby aquifer, using a pump.

The base-case unit is designed to consume 1 million Sm^3 natural gas from which 100 MWe net AC power is produced, and 0.88 million tonnes CO_2 is captured and injected annually. ZEUS can however be scaled to specific fields as applicable.

Advantages
- Reliable and affordable power with zero CO_2 emissions (100 percent capture rate).
- Reduces the need for retrofitting topside for brownfield projects due to less weight and space requirements for electrical equipment.
- Lower CAPEX and OPEX for greenfield projects.
- Patented combustion under high pressure ensures that the exhaust gas is liquified directly when cooled, simplifying the plant as pumps can be used for re-injection rather than compressors. This also removes the need for any costly post-processing of the exhaust. The power required for CC is estimated to be 60 MWel, compared to around 100 for traditional CC plants (combined cycle or LM2500 gas turbines).



Maturity

Technology Readiness Level (TRL)
- Subsea compression technology mature and utilized since 2015. Utilizing off-the-shelf technology for several parts.
- Pilot to qualify the high-pressure burner ready by 2024.
- Pilot to qualify turbine-generator for subsea application ready by 2025.
- ASU: Unmanned unit by 2027 and floating unit by 2030.

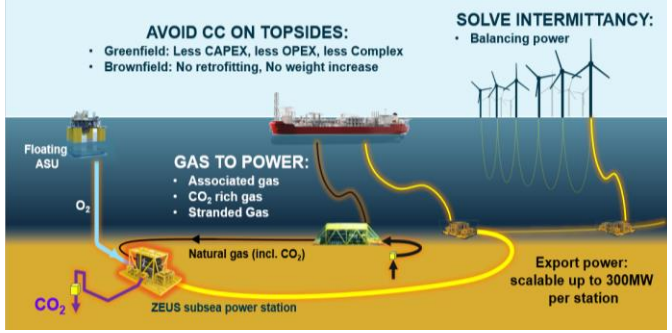
Commercial Readiness Level (CRL)
- Phase I (application for shallow water installations): Topside power station targeted for 2028
- Phase II (deep water): Subsea power station and floating ASU targeted for 2031.

Applications

Decarbonized upstream oil and gas activities
- Produce emission free power locally avoiding topside CC

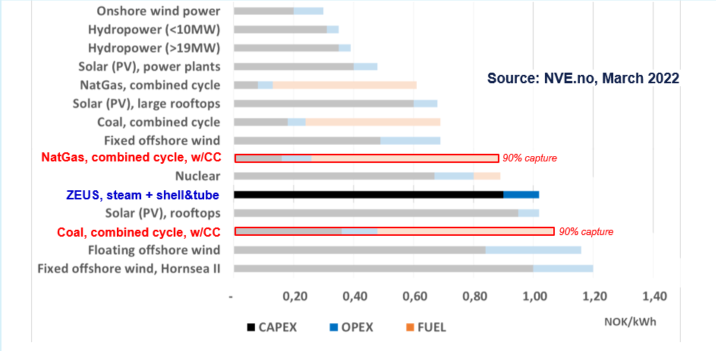
Compliment renewables, especially offshore wind
- Being dispatchable, deliver balancing power

Monetize problem gas (associated, CO_2 rich, stranded)
- Gas to produce power, not power to produce gas

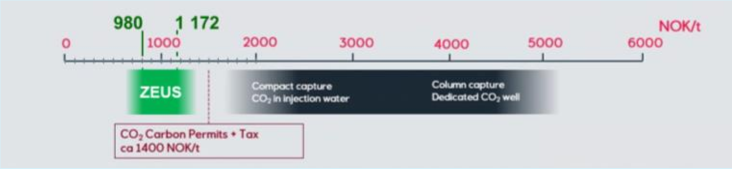


Costs

Levelized Cost Of Energy (LCOE)*
ZEUS is competitive with other carbon capture solutions. If including CO_2 offsets or EOR, the LCOE can be reduced to around 0.10 NOK/kWh**. Note, the prices on fuel and raw materials are varying and has increased since the estimates (graph below showing situation in March 2022).



Abatement costs for decarbonizing FPSO topsides lie in the range of 980 to 1200 NOK/tonne CO_2. In comparison, the LINCCS project shows a range of 1500 to above 5000 NOK/tonne CO_2 for other carbon capture technologies. Note, ZEUS has 100 percent carbon capture rate compared to 90 percent capture for alternatives.



*LCOE excludes company cost, cost of injection well and XT, cost of umbilical, cost of natural gas
** Assuming CO_2 tax savings of 50 USD/tonne CO_2 and selling power surplus, or 1 extra bbl of oil (EOR) of 50 USD/bbl

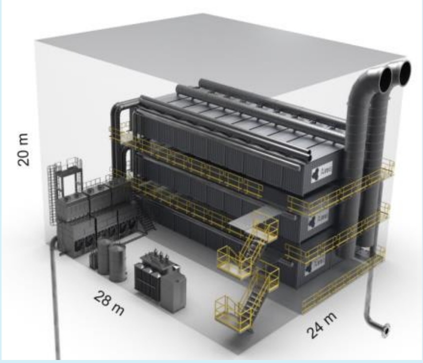
All information is used with permission from Aker Solutions

Gas-fired power hubs with CCS
Long-term considerations

- Natural gas is set to play a transitional role in the EU taxonomy. However, the aim will be to springboard gas solutions towards facilitating uptake of low-carbon gases through steadily tightening requirements.

- The European Commission approved a complementary climate delegated act in February 2022, inluding electricity production from gas as a sustainable activity, given that either any new or refurbished gas power plant meets the 100gCO_2e/kWh in lifecycle emissions criteria, or a number of alternative stringent criteria for facilities with a construction permit granted by 31 December 2030 [1].
    - One of these criteria include that a facility either must have direct emissions below 270gCO_2e/kWh of the output energy, or that annual direct GHG emissions of the activity do not exceed an average of 550kgCO_2e/kW of the facility's capacity over 20 years. Other criteria include that the activity must replace high-emitting electricity generation, not replace electricity from renewable energy and that the facility must be **designed to use renewable and/or low-carbon fuels** by December 31st 2035.

- A gas-fired power plant with CCS will likely be able to meeting the criteria and as such qualify as a sustainable activity under the EU taxonomy in the short term, as it displaces high-emitting electricity generation. However, the facility should be designed to use renewable and/or low-carbon fuels in the longer term to meet tightening requirements.
    - One solution could be to facilitate for co-firing solutions on the power plant, and in the longer term replace the turbines with turbines that can run on 100 percent low-carbon fuels.
    - Another alternative could be to replace the gas turbines with fuel cells for generating power. The Norwegian venture Alma Clean Power (see fact box) is currently developing high-efficient fuel cells that can run on multiple fuels, which could be a solution for the future.



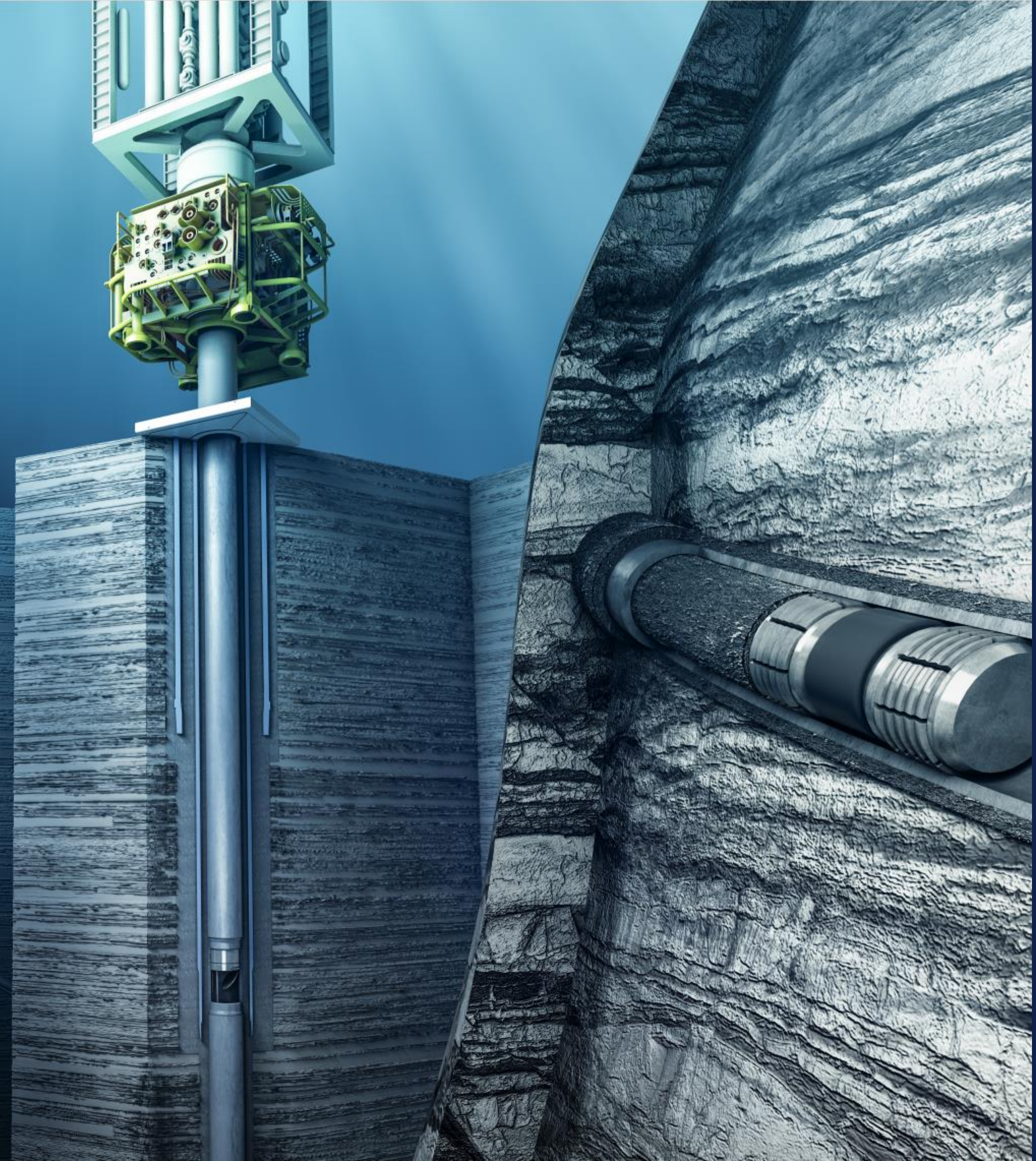
Alma Clean Power was established in 2021 in Bergen, Norway, with an ambition to establish a full-scale production of module-based fuel cells to support the decarbonization of ocean industries. The company is a venture from Clara Venture Labs, originated from Aker ASA's venture capital platform for industrial technologies and materials.

Alma Clean Power utilizes high-temperature solid oxide fuel cell (SOFC) technology to enable high-efficiency power generation. The fuel cell modules are 2 MW and comprise heat exchange and fuel recirculation systems providing superior electrical efficiency of >60% in addition to valuable heat. The fuel cells can operate on a variety of fuels, e.g., ammonia, hydrogen, LNG and methanol. If carbon-based fuels are applied, concentrated CO_2 will exit the fuel cell modules. This enables cost- and energy efficient carbon capture, which means that zero-emission power generation can be achieved also in carbon-based fuels. Key application areas are maritime shipping, offshore O&G, subsea, fish farming and remote lands.

Maturity
- R&D programs with academic and industrial partners since 1991
- 2023: Ammonia-powered fuel cell installed at Sustainable Energy Norwegian Catapult Centre's Energy House at Stord
- 2024: Ammonia-powered fuel cell installed on Viking energy (first ammonia fuel cell driven vessel)
- 2025: Mega production facility to be built
- 2026: Commercially available products

Advantages
- Can replace gas turbines offshore with a potential of reducing up to 90 percent of emissions in the oil and gas sector (dependent on fuel).
- Fuel efficiency increased from 20-35 percent to >60 percent compared to gas turbines.
- Enables cost- and energy efficient carbon capture of natural gas power generation.
- End user cost savings due to lower fuel consumption and lower CO_2 taxes.
- CAPEX competitive with electrification from shore (case dependent)
- The modular units can be operated independently or connected to scale up the power production.

[1] European Commission, 2022



3.7

Energy efficiency through water management: Background

Energy efficiency through water management

Overview of options

Water-flooding is a widely used technique for pressure maintenance or improving sweep efficiency. Incremental recovery of water-flooding ranges from 15 to 25 percent. Nonetheless, water-flooding is an energy-intensive activity. Water injection systems typically consume 30 to 50 percent of field total power consumption. For many oilfields on the NCS, the percentage is much higher with more than half of the energy demand being from water injection pumps. Thus, water-flooding significantly contributes to the amount of GHG emissions for oil production.

Short description

Upstream CO_2 emissions on the NCS per boe increases over the lifetime of the fields. For waterflooded fields, CO_2 emissions per boe produced will increase significantly with increasing water-cut. The emissions stem from generation of power, heat and flaring.

It is possible to reduce the CO_2 footprint significantly by ensuring stable displacement to avoid or delay water breakthrough, and limit water separation topside to reduce energy consumption. This can be obtained by several different technologies, such as:

- Limit water production through 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 opportunities.

Reservoir basics

Water management is an integral part of the reservoir drainage strategy for an oil field. The challenge is that gathering sufficient reservoir knowledge is expensive and may not be prioritized for smaller fields. For a larger licence however, more cost is at stake and more effort in reservoir investigation is done.

Priority related to reservoir handling in general and water management in particular should be:

1. Development of a robust drainage strategy based on reservoir understanding, locations of wells, well/reservoir parameters, etc. Considerable knowledge and information is available and needs to be utilised.
2. Blockage of water via polymers or cement to block water inflow from the reservoir (during well construction).
3. Utilizing passive or active inflow blockage (Smart Completion) for water control downhole (see below). May be retrofitted in case of well refurbishment.
4. Separation at seabed or downhole in order to reduce energy consumption for injection and remove need for gas lift.
5. Finally: Efficient separation topside, e.g. low turbulent chokes, VDS driven pumps.

Unless the first steps are taken, the latter ones will be less effective.

Energy efficiency through water management
Views on scope and scaling

Illustration: iStock

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 used at a varying degree on the NCS. Others needs pilots and/or R&D.
- Option for a more than 50 percent reduction in NCS CO_2 emission – at the cost of 10 percent lost oil from high-water-producing fields [1].

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 usage.
- 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 CO_2 storage.

Accelerating developments
- Pilots and R&D could speed up implementation
- Electrical ICV's, e.g. Manara from Schlumberger

[1] Arne Stavland, NORCE, Rystad Energy, Forskningsrådet; Reduksjon av klimagassutslippene fra olje-og gassproduksjon på norsk sokken med 50% innen 2030

Energy efficiency through water management

Views on GHG emission reduction potential and major challenges and opportunities

GHG reduction potential

Target emission sources
For oil fields, water injection accounts for around 50 percent of total emissions. In addition, most waterfloods on the NCS are using gas-lift. High water-cut wells do need considerable amounts of gas lift to flow and are hence driving up energy consumption. By either reducing the need for water injection (and gas lift) 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 percent 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
The reduction potential is extremely case dependent and difficult to quantify. 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 gas lift) versus the value of the oil and the costs of implementing the technology.

Main challenges and opportunities

Development and implementation obstacles
- Historically relatively cheap energy (for water injection and gas lift), although energy prices are increasing.
- High costs for water displacement technologies.
- Water cut and energy use for water management increasing with lifetime of installation.
- Need a good 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 not sustainable and will be costly.
- Downhole separation technologies are available, e.g. 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 might develop.

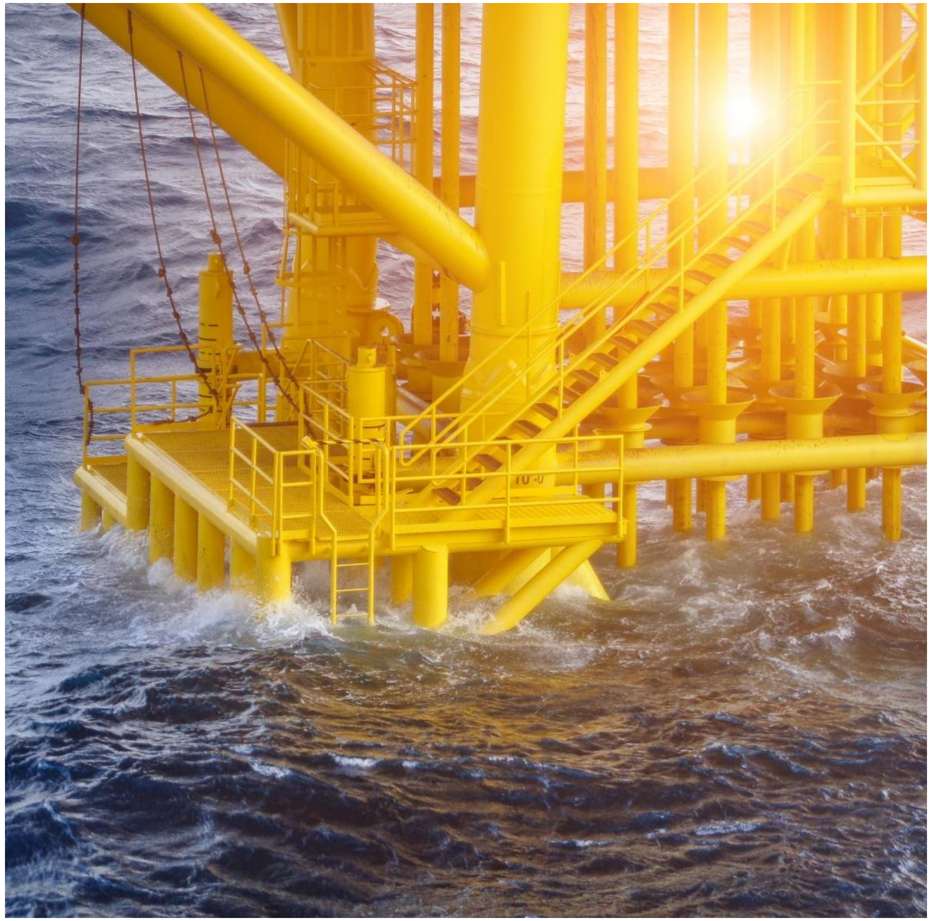
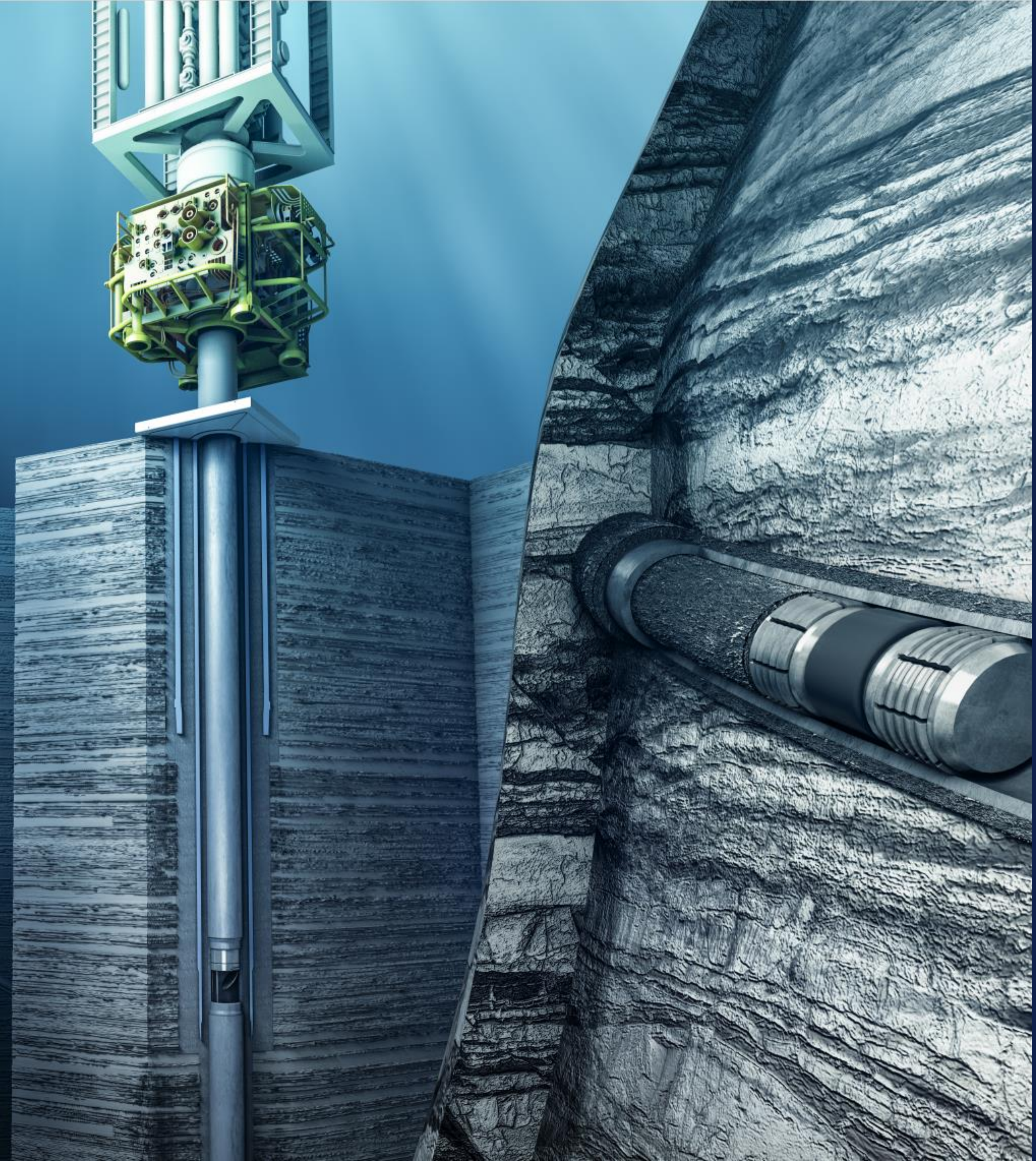


Photo: GettyImages/chain45154



3.8

Energy efficiency through water management: Perspectives on how to accelerate impact

DNV

Energy efficiency through water management
Realistic reduction potential and key advantages

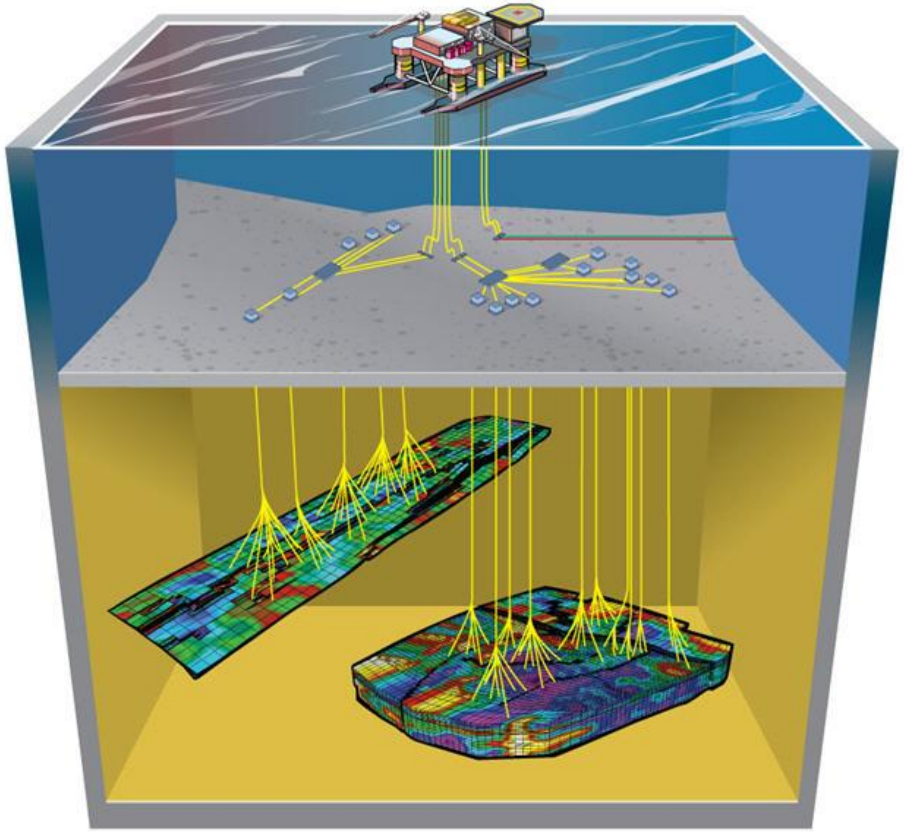
- Water-flooding is a widely used technique for pressure maintenance or improving sweep efficiency. Incremental recovery of water-flooding ranges from 15 to 25 percent. Nonetheless, water-flooding is an energy-intensive activity, and water injection systems typically consume 30 to 50 percent of field total power consumption.

- The potential for energy optimization for water management stems from topside with optimal use of water pumps and compressors, subsea water treatment with separation and reinjection of water, and control of well inflow by smart completion. Even if the choice of solution is highly case sensitive, the key to success for water management will be good reservoir understanding for development of a robust drainage strategy. Considerable knowledge and information is available and needs to be utilised.

- Estimating the realistic emission reduction potential and resulting costs is extremely difficult. As such, this chapter does not go into details on emission reductions or cost estimates. Instead, we try to highlight the most important considerations, the main ways to accelerate implementation and development, as well as the current state and research needs of technology.

Key advantages and opportunities

- Reducing energy use and resulting emissions. The operational costs can be reduced due to lower cost of CO_2 tax and fuel.
- Potential synergies with CCS value chains, particularly for late-life oil production
- With more stringent emission regulations expected globally, there is a potential for further developing an export market on novel technologies from Norway.



Energy efficiency through water management
Major obstacles and possible mitigations

As there are several obstacles related to water management it is important to focus on how to mitigate them. Below, we list some of the main identified obstacles for **water management**, with possible mitigations in order to accelerate development and implementation. Note that cost aspects are covered separately.

Main development and implementation obstacles

- **High costs of new water displacement technologies**: With increasing energy cost and CO_2 price, the incentive for promoting new and improved technologies will increase. Co-operation between operators, vendors and expert areas is key to promote technology developments and remove silos.
- Standardization of technologies will bring down costs and risks, as will strengthening regulation requirements to apply new technology in license and PDO-processes.
- **Energy-intensive tail-end production:** Water cut and energy use for water management increasing with lifetime of installation. The energy use (and thus costs and emissions) for water management increases exponentially towards tail-end production.

Possible mitigations and how to accelerate development

High costs for water displacement technologies

- Several mature and novel technologies can solve issues related to water management (see following page).
- 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.
- With increasing energy cost and CO_2 price, the incentive for promoting new and improved technologies will increase. Co-operation between operators, vendors and expert areas is key to promote technology developments and remove silos.
- Standardization of technologies will bring down costs and risks, as will strengthening regulation requirements to apply new technology in license and PDO-processes.

Energy-intensive tail-end production

- Several mature and novel technologies can solve issues related to water management (see following page).
- New projects (greenfield): Several possibilities available to limit water inflow and the energy used for water management. However, the merit order is important, and one should always start with developing a robust drainage strategy based on sufficient reservoir understanding.
- Existing installations (brownfield): For highest water-cut fields, shut-down of fields in the tail of their lifetime might be a more economically viable solution with increasing CO_2 and energy prices (and decreasing oil prices).

Topics categorisation:
1. Water injection energy consumption
2. Separation oil/water energy consumption
3. Stop/control water in-flow.

Energy efficiency through water management
Technology deep-dive for water management (1/2)

In the table below, mature and novel technologies for water management are listed and assessed based on maturity and impact on reducing GHG emissions on the NCS (carbon footprint). The technologies are categorized into three topics, depending on the issues they aim to solve: 1) energy consumption for water injection, 2) energy consumption for separation of oil and water, and 3) stop or control water in-flow.

Technology and category	Maturity	Impact on carbon footprint	References
1.1: Topside • Variable speed drive (VDS)/optimal use of water pumps and compressors • Low turbulent (low share) chokes to reduce emulsions and mixing	• Variable speed drive (VDS) is standard and mature technology applied for most new projects and reduced energy consumption significantly due to no need for choking and recirculation for flow control. • Low turbulent chokes are common technology applied with success, primary for oil fields to enhance separation efficiency and reduce energy consumption.	• Cost efficient for new projects (greenfield). • Retrofitting on existing installations (brownfield) depends on remaining life for field and realistic payback time.	Sustainable oil production with a low shear Typhoon Valve System - Mokveld.com
1.2: Topside • Topside energy optimisation	• A number of technologies are applied for energy consumption optimisation both during design and operation – driven by ESG goals and CO2 tax. • Installing "power meters" in CCR and KPI for energy consumption has proven to give good short time results.	• Operators claim up to 5 percent reduction in energy consumption just by on-line monitoring energy usage.	Reservoir management and production optimization - Bru21 – NTNU; Machine learning to improve NCS efficiency (og21.no)
2: Subsea technology • Subsea water treatment, separation and reinjection (e.g. SeaBox)	• Subsea water injection technology reduced need for topside system with connected risers and pipelines, and reduces the need for chemical treatment. Consists of water filtration, treatment and injection in a contained box on the sea bottom, or directly in the subsea well slot. • The technology is developed and tested, but limited applications.	• Reduction in power consumption as pressure drop is minimized (no pipeline/riser required).	Seabox Subsea Water Treatment Technology (nov.com)

Topics categorisation:
1. Water injection energy consumption
2. Separation oil/water energy consumption
3. Stop/control water in-flow.

Energy efficiency through water management
Technology deep-dive for water management (2/2)

Technology and category	Maturity	Impact on carbon footprint	References
3.1: Smart completion/Zone Control and in-well technologies • ICV (Inlet control Valves) • EICV (Electric Inlet Control Valves) • In-well technologies such as AICD (Autonomous Inflow Control Device)	• The passive and hydraulic actuated valves (ICV) are in use today. • Electrical operated (EICV) has higher potential as it provides more opportunities to control zones and gives better monitoring, but is best suited with an all-electric X-tree concept.	• Specific numbers not relevant as this should be seen in context of overall reservoir management	Intelligent Completions & Smart Well Technology | Schlumberger; (slb.com) eICV – ouronova
3.2: Downhole separation and reinjection. Downhole pump required.	• Downhole separation is combined with smart completion, and consist of a separation unit, inflow valves, monitoring and control systems and an ESP (Electrical Submersible Pumps). • The technology is developed but in limited use due to risk and need for replacement of ESP which requires replacement of the whole well completion involving a lengthy and costly rig hiring. Time to failure for ESP is less than 2 yrs. Thus there is a need to develop more reliable and easy retrievable ESP for this application to succeed, e.g. wireline retrievable downhole ESP.		
3.3: In-depth water shut-off using chemicals	1. Development of a robust drainage strategy based on reservoir understanding, locations of wells, well/reservoir parameters, etc. Considerable knowledge and information is available and needs to be utilised. 2. Blockage of water via polymers or cement to block water inflow from the reservoir (during well construction). 3. Separation as close to the reservoir at possible: at seabed or downhole in order to reduce energy consumption and pump work.		

DNV

4. Case study of selected measures

Case study of selected measures
General description

In order to compare some of the most promising measures on a cost basis, DNV has performed a high-level study of four separate concepts for reducing GHG emissions on a given case on the NCS. For each concept, the CAPEX and OPEX have been estimated, the LCOE and abatement cost have been calculated, and sensitivity analysis have been performed. The concepts are compared against the status quo of "doing nothing".

General case description

- Three platforms on the NCS are to be fully electrified.
- The platforms are located 200 km from shore and 50km apart from each other.
- Each platform has a peak load of 85 MW and a capacity factor of 50%.
- The platforms are originally fully supplied by gas turbine generators located on the platform with gas turbine efficiency of 30%.

Four concepts have been assessed, including the status quo

Concept	Name	Description
Case 0 (status quo)	Do nothing	Running traditional gas-fired turbines without modifications and continue paying the resulting fuel cost, O&M cost and CO_2 tax.
Case 1	Power from shore with a coordinated build-out	200 km HVDC cable from shore with dedicated platform (jacket) for DC equipment with a power rating of 250 MW
Case 1.1	Power from (or to) shore with a coordinated build-out and floating offshore wind turbines	Same as case 1 including floating wind turbines with an installed capacity of 85 MW (similar to penetration level of Hywind Tampen) and capacity factor of 46%
Case 2	Gas-fired power hub offshore with CCS	Sevan cylinder design power hub as stand-alone solution located close to the platforms with a power rating of 250 MW
Case 2.1	Gas-fired power hub offshore with CCS and floating offshore wind turbines	Same as case 2 including floating wind turbines with an installed capacity of 85 MW (similar to penetration level of Hywind Tampen) and capacity factor of 46%

Important assumptions

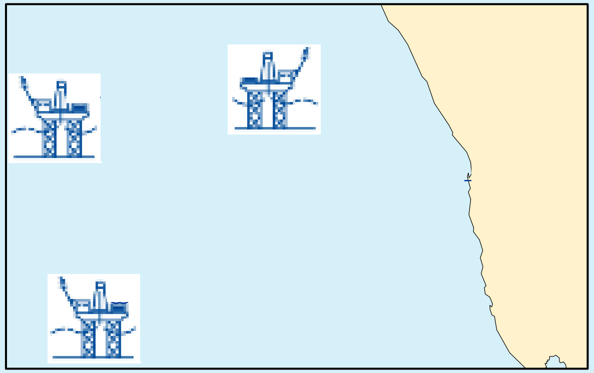
- A retrofitting cost of 2000 MNOK per platform is assumed for full electrification. This will, however, be extremely case dependent - based on information from NPD, the cost varies from around 1000 to above 5000 MNOK.
- Lifetime of 25 years.
- A Weighted Average Cost of Capital (WACC) of 7% and inflation rate of 1.45%/yr.
- Assumed electricity price of 530 NOK/MWh and natural gas price of 2.4 NOK/Sm^3 (the alternative price of exporting natural gas).
- Assumed CO_2 tax of 2000 NOK/tonne CO_2, based on targets in 2030 from the Norwegian government. In comparison, today's CO_2 tax levels for O&G lie around 1600 NOK/tonne CO_2.
- The petroleum taxation system, onshore grid investments, loss of revenue due to downtime*, and power losses are not considered.
- The CO_2 abatement is discounted with the same discount rate (WACC) when calculating the abatement cost.

*The required downtime for retrofitting is highly project specific. Electrification of assets can be completed within normal maintenance stops, depending on the technical basis and careful planning. In other cases, additional downtime will be required.

Case study of selected measures
Case 0: Do nothing

Description

- Status quo: Do nothing, i.e. running the traditional gas-fired turbines without modifications on the platforms.
- This case does not require any additional CAPEX investments.
- The OPEX consists of O&M costs for the turbines (overhaul and replacement of hot section), fuel costs and CO_2 tax.



Assumptions and resulting LCOE and abatement cost

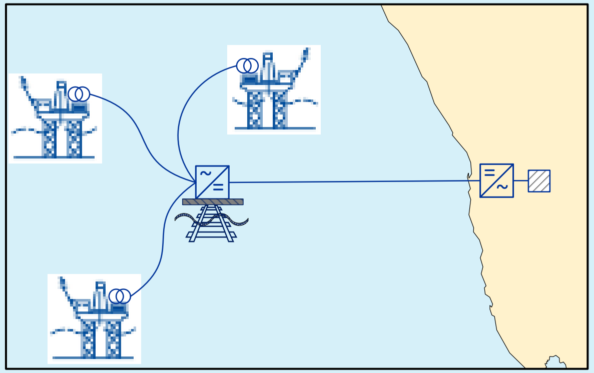
Note: Sensitivity analysis have been performed, see following slides

Parameter	Value	Unit
Capacity factor per platform	50	%
Gas turbine efficiency	30	%
Electricity consumption from shore	-	TWh/year
Electricity produced offshore	1.095	TWh/year
Natural gas consumption	3.65 (0.33)	TWh/year (billion Sm3/year)
CO_2 emitted	722,700	Tonne CO_2/year
CO_2 abated	-	Tonne CO_2/year
CAPEX: Retrofit	N/A	MNOK
CAPEX: Equipment	N/A	MNOK
OPEX: O&M	83.3	MNOK/year
OPEX: Electricity cost	-	MNOK/year
OPEX: Fuel cost	788.4	MNOK/year
OPEX: CO_2 price	1,445	MNOK/year
LCOE	**2.41**	**NOK/kWh**
Abatement cost	**N/A**	**NOK/tonne CO_2 abated**

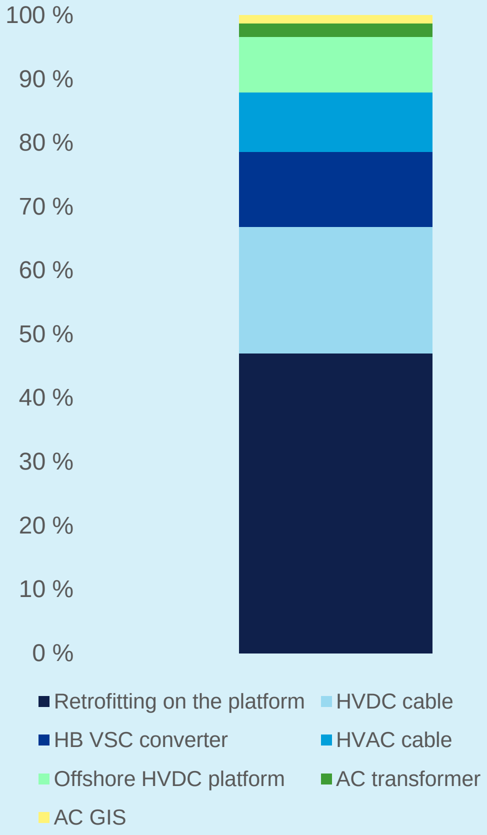
Case study of selected measures
Case 1: Power from shore (coordinated)

Description

- One 200 km HVDC cable connecting an offshore HVDC platform (jacket) with the onshore power grid.
- From the HVDC platform, three 66kV AC cables are used to connect the O&G platforms to the jacket.
- The CAPEX breakdown is shown in the figure to the right, based on DNV insights on cost of equipment.
- The OPEX consists of O&M costs and cost of purchasing power from the grid.



CAPEX breakdown



Assumptions and resulting LCOE and abatement cost

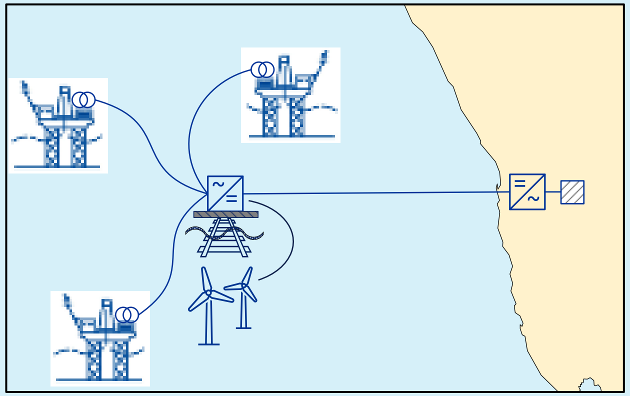
Note: Sensitivity analysis have been performed, see following slides

Parameter	Value	Unit
Total power rating	250	MW
Capacity factor per platform	50	%
Electricity consumption from shore	1.095	TWh/year
Electricity produced offshore	-	TWh/year
Natural gas consumption	-	TWh/year
CO_2 emitted	-	Tonne CO_2/year
CO_2 abated	722,707	Tonne CO_2/year
CAPEX: Retrofit	6,000	MNOK
CAPEX: Equipment	6,778	MNOK
OPEX: O&M	123.2	MNOK/year
OPEX: Electricity cost	580.4	MNOK/year
OPEX: Fuel cost	-	MNOK/year
OPEX: CO_2 price	-	MNOK/year
LCOE	**1.77**	**NOK/kWh**
Abatement cost (CO_2 discounted)	**2,678**	**NOK/tonne CO_2 abated**
Abatement cost (CO_2 not discounted)	**1,167**	**NOK/tonne CO_2 abated**

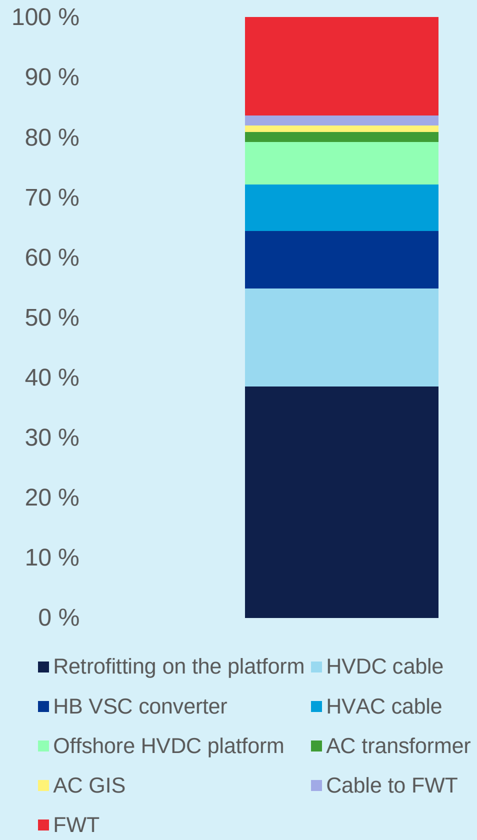
Case study of selected measures
Case 1.1: Power from shore (coordinated) and floating offshore wind

Description

- Similar connection to shore as for Case 1.
- In addition, floating offshore wind turbines (FWT) are connected to the HVDC jacket with a total installed capacity of 85 MW (similar to Hywind Tampen penetration level) and a capacity factor of 46 percent.
- The CAPEX breakdown is shown in the figure to the right, based on DNV insights on cost of equipment.
- The FWT helps reduce the total OPEX as a lower amount of electricity needs to be purchased.



CAPEX breakdown



Assumptions and resulting LCOE and abatement cost

Note: Sensitivity analysis have been performed, see following slides

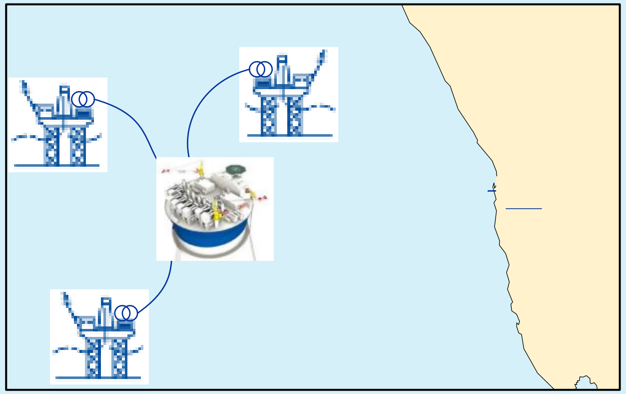
Parameter	Value	Unit
Total power rating cable	250	MW
Total power rating FWT	85	MW
Capacity factor per platform	50	%
Capacity factor FWT	46	%
Electricity consumption from shore	0.75	TWh/year
Electricity produced offshore	0.34	TWh/year
Natural gas consumption	-	TWh/year
CO_2 emitted	-	Tonne CO_2/year
CO_2 abated	722,707	Tonne CO_2/year
CAPEX: Retrofit	6,000	MNOK
CAPEX: Equipment	9,578	MNOK
OPEX: O&M	154.9	MNOK/year
OPEX: Electricity cost	398.8	MNOK/year
OPEX: Fuel cost	-	MNOK/year
OPEX: CO_2 price	-	MNOK/year
LCOE	**1.84**	**NOK/kWh**
Abatement cost (CO_2 discounted)	**2,786**	**NOK/tonne CO_2 abated**
Abatement cost (CO_2 not discounted)	**1,214**	**NOK/tonne CO_2 abated**

Case study of selected measures

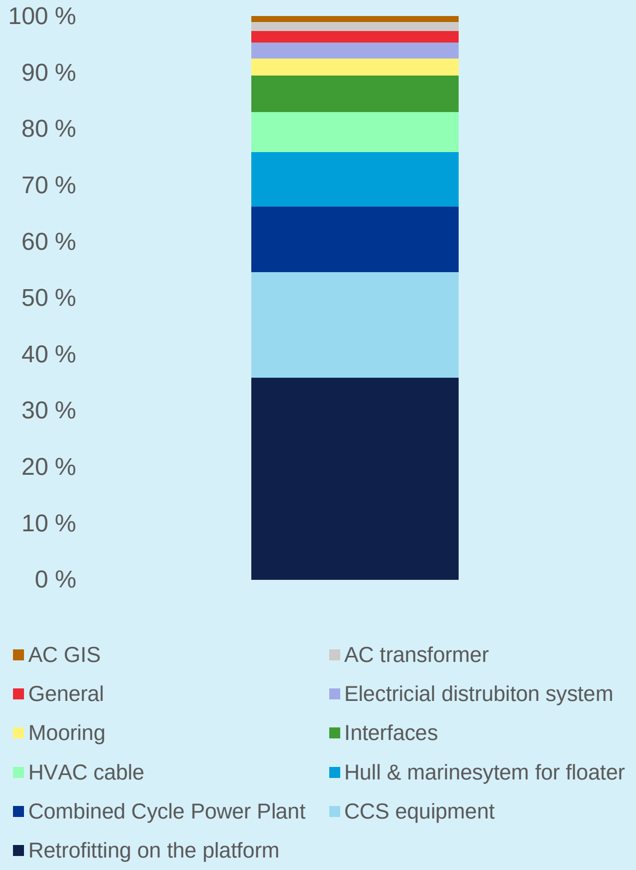
Case 2: Gas-fired power hub offshore with CCS

Description

- A gas-fired power hub with carbon capture installed on a Sevan floater without power from shore. Similar AC power supply to the platforms assumed as for Case 1.
- Cost data, both for the power hub as well as interfaces (reservoir and drilling & well, CO_2 and natural gas flow line), are obtained by scaling the costs from the Blå Strøm concept. The OPEX for CO_2 storage is assumed to be 200 NOK/tonne CO_2 in the base case.
- The CAPEX breakdown is shown in the figure to the right.
- The OPEX consists of O&M costs, fuel costs and CO_2 tax.



CAPEX breakdown



Assumptions and resulting LCOE and abatement cost

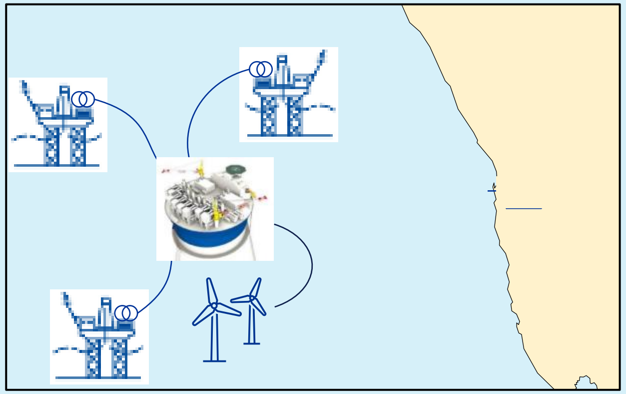
Note: Sensitivity analysis have been performed, see following slides

Parameter	Value	Unit
Total power rating power plant	250	MW
Capacity factor per platform	50	%
Gas turbine efficiency power plant	55	%
CO_2 capture rate	90	%
Electricity consumption from shore	-	TWh/year
Electricity produced offshore	1.095	TWh/year
Natural gas consumption	1.99 (0.18)	TWh/year (billion Sm3/yr)
CO_2 emitted	39,420	Tonne CO_2/year
CO_2 stored	357,784	Tonne CO_2/year
CO_2 abated	683,286	Tonne CO_2/year
CAPEX: Retrofit	6,000	MNOK
CAPEX: Equipment	10,759	MNOK
OPEX: O&M	76.2	MNOK/year
OPEX: Electricity cost	-	MNOK/year
OPEX: Fuel cost	430	MNOK/year
OPEX: CO_2 price	70.9	MNOK/year
OPEX: CO_2 storage	7	MNOK/year
LCOE	**2.04**	**NOK/kWh**
Abatement cost (CO_2 discounted)	**3,271**	**NOK/tonne CO_2 abated**
Abatement cost (CO_2 not discounted)	**1,425**	**NOK/tonne CO_2 abated**

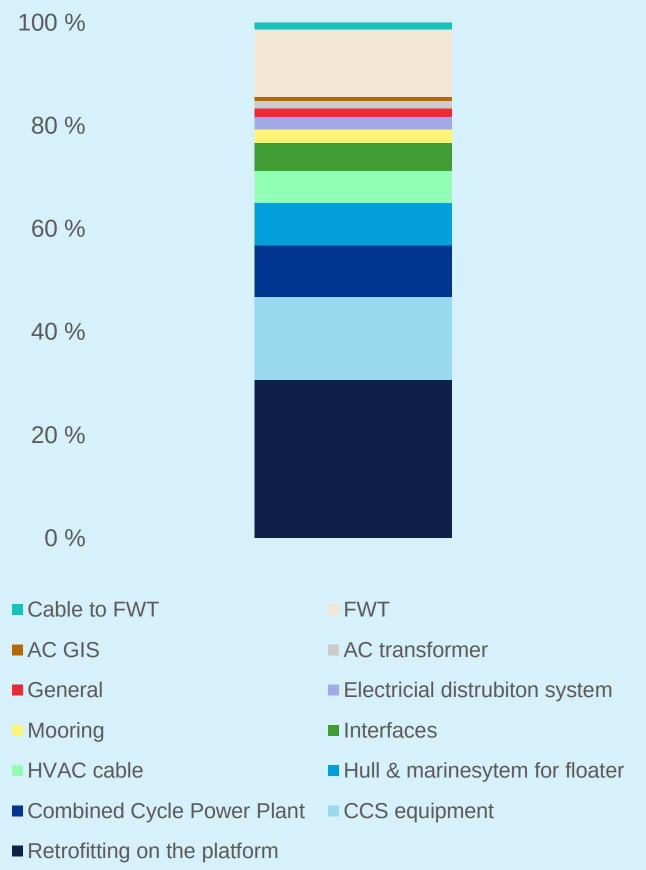
Case study of selected measures
Case 2.1: Gas-fired power hub offshore with CCS and floating offshore wind

Description

- Similar gas-fired power hub as described in Case 2, and similar AC power supply to the platforms assumed as for Case 1.
- In addition, floating offshore wind turbines (FWT) are connected to the power hub, similar as for Case 1.1.
- The CAPEX breakdown is shown in the figure to the right.
- The FWT helps reduce the OPEX due to lower use of fuel, reducing fuel cost and costs related to CO_2 tax.



CAPEX breakdown



Assumptions and resulting LCOE and abatement cost

Note: Sensitivity analysis have been performed, see following slides

Parameter	Value	Unit
Total power rating hub	250	MW
Total power rating FWT	85	MW
CO_2 capture rate	90	%
Electricity consumption from shore	-	TWh/year
Electricity produced offshore from FWT	0.34	TWh/year
Electricity produced offshore from hub	0.75	TWh/year
Natural gas consumption	1.37 (0.12)	TWh/year (billion Sm3/yr)
CO_2 emitted	27,090	Tonne CO_2/year
CO_2 stored	243,807	Tonne CO_2/year
CO_2 abated	695,617	Tonne CO_2/year
CAPEX: Retrofit	6,000	MNOK
CAPEX: Equipment	13,558	MNOK
OPEX: O&M	108	MNOK/year
OPEX: Electricity cost	-	MNOK/year
OPEX: Fuel cost	295.5	MNOK/year
OPEX: CO_2 price	54.2	MNOK/year
OPEX: CO_2 storage	48.8	MNOK/year
LCOE	**2.11**	**NOK/kWh**
Abatement cost (CO_2 discounted)	**3,326**	**NOK/tonne CO_2 abated**
Abatement cost (CO_2 not discounted)	**1,449**	**NOK/tonne CO_2 abated**

Case study of selected measures

Summary of results using base case assumptions

The following high-level conclusions can be drawn from the results:

- **The most expensive option measured in LCOE is not doing anything** (Case 0). This is due to the high CO_2 tax and fuel cost (the alternative value of exporting natural gas).
- **Case 1 (Power from shore through a coordinated approach) has the lowest LCOE and abatement cost** due to lower investment costs compared to the alternatives. However, it must be noted that this does not include investment costs for upgrading the grid capacity onshore, which might be needed depending on the location of the platforms.
- Case 2 (Gas-fired power hub offshore with CCS) has a higher LCOE than power from shore, however is a **stand-alone solution and thus not dependent on the onshore grid**. Note that a case with gas-fired power hub onshore with CCS has not been assessed in this case study, as the concept is similar to electrification through power from shore.
- **Introducing floating offshore wind helps reduce the OPEX** as it either reduces the cost of purchasing electricity (Case 1.1.) or reduces the cost of fuel and CO_2 tax (Case 2.2). However, the LCOE and abatement cost is increased due to higher investment costs.
- All cases have an abatement cost exceeding the expected CO_2 price in 2030. However, it is not unreasonable to expect a further increase in the CO_2 tax beyond 2000 NOK/tonne CO_2.
- It is important to note that this case study is **high-level** and that the actual cost of various measures are **extremely case dependent.** Moreover, potential project specific cost factors have been excluded, such as downtime for retrofitting and associated postponed revenue*. The following slides present **sensitivity analysis** to show how the results are affected by a change in the assumptions.

Concept	**Power purchased from shore** TWh/year	**Power produced offshore** TWh/year	**Fuel consumption** TWh/year	**CO_2 emitted** Tonne CO_2/year	**CO_2 abated** Tonne CO_2/year	**CAPEX** MNOK	**O&M costs** MNOK/yr	**CO_2 tax** MNOK/yr	**Fuel/ electricity cost** MNOK/yr	**Abatement cost** NOK/tonne CO_2 abated	**LCOE** NOK/kWh
0: Do nothing	-	1.095	3.65	722,707	-	N/A	83	1,455	788	**N/A**	**2.41**
1: Power from shore (coordinated)	1.095	-	-	-	722,707	12,778	123	-	580	**2,678**	**1.77**
1.1: Floating wind turbines and power from (to) shore	0.75	0.34	-	-	722,707	15,578	155	-	399	**2,786**	**1.84**
2. Gas-fired power hub offshore with CCS	-	1.095	1.99	39,420	683,286	16,759	76	79	430	**3,271**	**2.04**
2.1: Floating wind turbines and gas-fired power hub offshore with CCS	-	1.095	1.37	27,090	243,807	19,559	108	54	300	**3,326**	**2.11**

*The required downtime for retrofitting is highly project specific. Electrification of assets can be completed within normal maintenance stops, depending on the technical basis and careful planning. In other cases, additional downtime will be required.

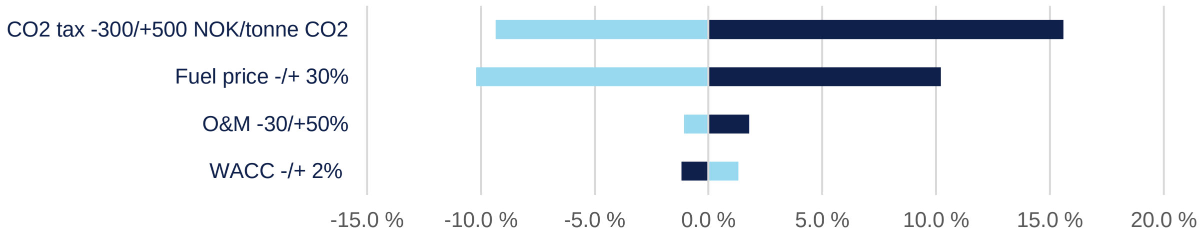
Case study of selected measures
Sensitivity analysis

For the sensitivity analysis, we have used the following uncertainty ranges for all cases:
- CAPEX of retrofitting per platform: -1000/+ 3000 MNOK (base: 2000 MNOK)*
- CAPEX on equipment: -30/+50%
- O&M: -30/+50%
- Power price: +/- 30% (base: 53 EUR/MWh)
- Fuel price: +/- 30% (base: 2.4 NOK/Sm^3)
- CO_2 price: -300/+500 NOK/tonne CO_2 (base: 2000 NOK/tonne CO_2)
- OPEX CO_2 storage: -/+200 NOK/tonne CO_2 (base: 200 NOK/tonne CO_2)**
- WACC -/+2%

The analysis show that the CAPEX for retrofitting of the platforms have the highest impact (positive and negative) for most cases. This is due to the fact that the cost of retrofitting is extremely case dependent and as such the uncertainty ranges are high. Even with a low retrofitting cost, the abatement cost is higher than the CO_2 price for all cases. Although not assessed here, the abatement cost could be lower than the CO_2 price in the event of several assumptions being reduced simultaneously (e.g. both a lower CAPEX of retrofitting and a lower CAPEX on equipment). Moreover, it is not unreasonable to expect a further increase in the CO_2 tax beyond 2000 NOK/tonne CO_2. For business as usual (the "do nothing" case), the CO_2 tax and fuel price have the highest impact on the results.

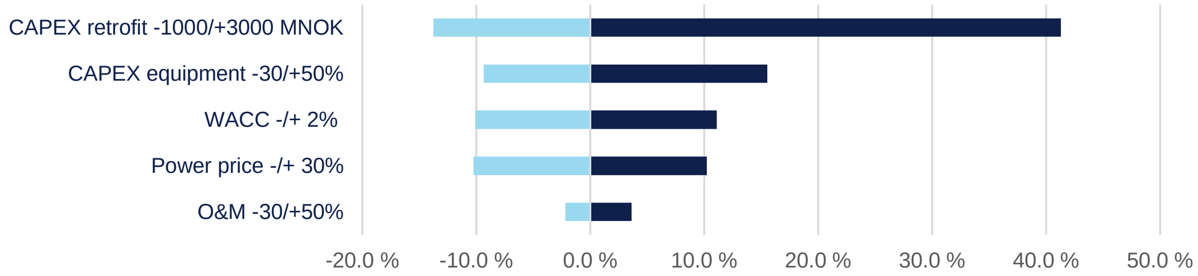
As no uncertainty has been applied to the power production or the CO2 abated, the results shown below (percentage change) apply to both the LCOE and the abatement cost.

Case 0: Do nothing (status quo)



Change with highest impact	Impact on cost	LCOE NOK/kWh	Abatement cost NOK/tonne CO_2
No change	0%	2.41	N/A
CO_2 tax increased with 500 NOK	+15.6%	2.78	N/A
Fuel price decreased with 30%	-10.2%	2.16	N/A

Case 1: Power from shore (coordinated)



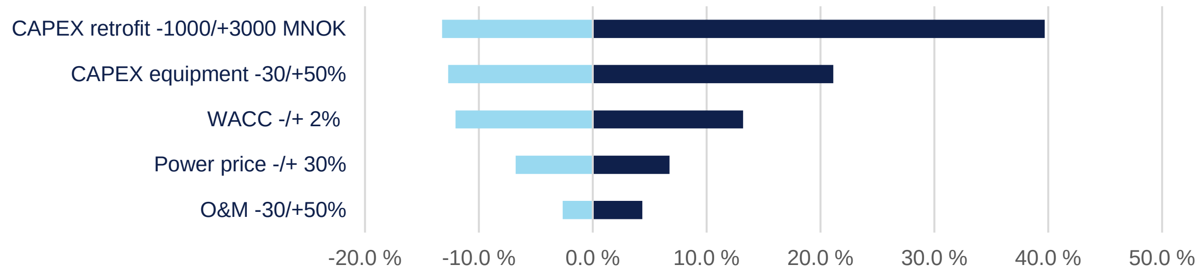
Change with highest impact	Impact on cost	LCOE NOK/kWh	Abatement cost NOK/tonne CO_2
No change	0%	1.77	2,678
CAPEX retrofit increased with 3000 MNOK	+41.3%	2.50	3,784
CAPEX retrofit decreased with 1000 MNOK	-13.8%	1.52	2,309

*Based on dialogue with NPD on typical ranges of retrofitting costs for full electrification.
**Case 2 and 2.1 include CAPEX for developingCO_2 storage (i.e. low OPEX for storage) but the storage could also be operated by an external party (i.e. higher OPEX for storage).

Case study of selected measures

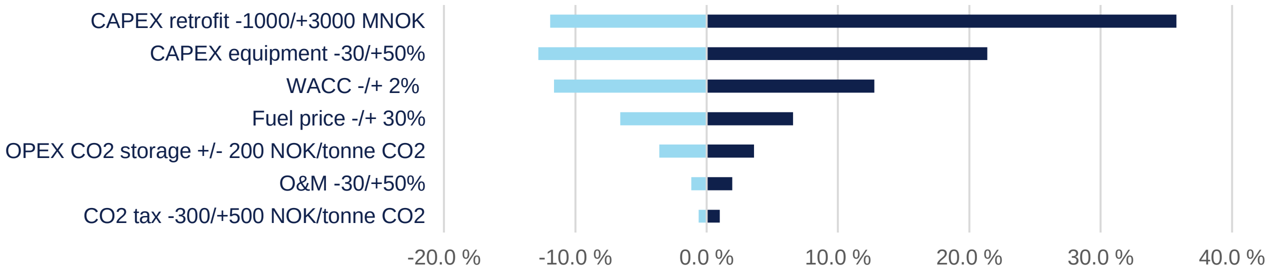
Sensitivity analysis

Case 1.1: Power from shore (coordinated) and floating offshore wind



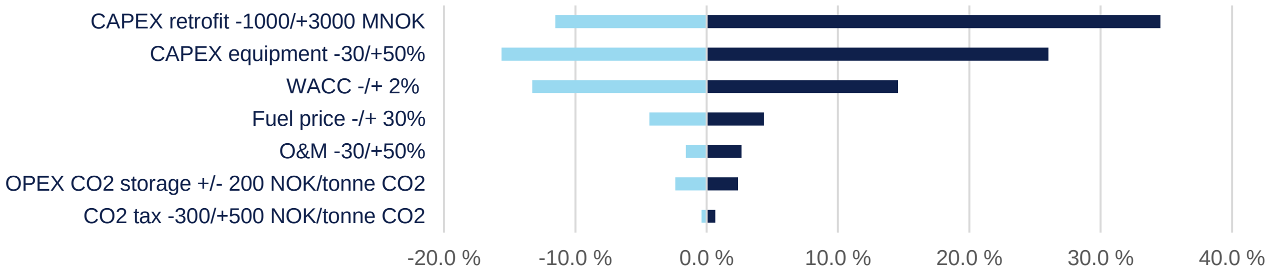
Change with highest impact	Impact on cost	LCOE NOK/kWh	Abatement cost NOK/tonne CO_2
No change	0%	1.84	2,786
CAPEX retrofit increased with 3000 MNOK	+39.7%	2.57	3,892
CAPEX retrofit decreased with 1000 MNOK	-13.2%	1.60	2,417

Case 2: Gas-fired power hub offshore with CCS



Change with highest impact	Impact on cost	LCOE NOK/kWh	Abatement cost NOK/tonne CO_2
No change	0%	2.04	3,271
CAPEX retrofit increased with 3000 MNOK	+35.8%	2.77	4,441
CAPEX equipment decreased with 30%	-12.8%	1.78	2,851

Case 2.1 : Gas-fired power hub offshore with CCS and floating offshore wind



Change with highest impact	Impact on cost	LCOE NOK/kWh	Abatement cost NOK/tonne CO_2
No change	0%	2.11	3,326
CAPEX retrofit increased with 3000 MNOK	+34.6%	2.84	4,475
CAPEX equipment decreased with 30%	-15.6%	1.78	2,806

5. Scope 3 emissions

Key considerations for the Norwegian oil and gas/energy industry

Outline of chapter

Generally, scope 3 reporting is immature at present, with companies either not reporting on scope 3 emissions at all, or only on a select few of the total of 15 categories for upstream and downstream emissions outlined by the GHG Protocol.

That said, there is an increasing emphasis on companies taking greater responsibility for the emissions occurring in their respective value chains. Regulators are starting to consider scope 3 emissions to ensure companies take a greater degree of value chain responsibility, while for stakeholders such as investors – scope 3 emissions are quickly taking a center stage of focus as a pertinent source of climate transition risk. Key reasons for this increasing focus on scope 3 is that it often represents, to varying degrees, the largest component of a company's value chain carbon footprint (total scope 1, 2 and 3 emissions – see appendix A for more details).

Accordingly, the first half of this chapter will outline the scope 3 discussion for the oil and gas industry today – and outline some key considerations for the future by discussing:

- **Use of sold products:** This chapter will first discuss where the oil and gas scope 3 footprint is, notably category 11 – "use of sold products" – as well as the relevance of other categories (the focus of this study is category 11). The focus is on natural gas, as most of the reduction from use of oil will come from a reduced demand due to alternatives (such as electrification of transport).
- **Scope 3 for NCS companies and for Norway:** This will set the stage for a discussion on how the pressures are building for companies to work to reduce their scope 3 emissions, and what pressures could emerge for Norway as an exporter of fossil fuels.
- **Scope 3 in a REPower EU context:** Finally, the impact of REPower EU and the combination of energy security and decarbonization aims will be discussed, with related scope 3 angles to the key measures outlined by the plan.

The second part of this chapter will investigate means for reducing scope 3 emissions from the Norwegian oil and gas industry – focusing on:

- **Natural gas power with CCS**
- **Blue hydrogen production and hydrogen derivatives**

5.1

Why scope 3 emissions matter

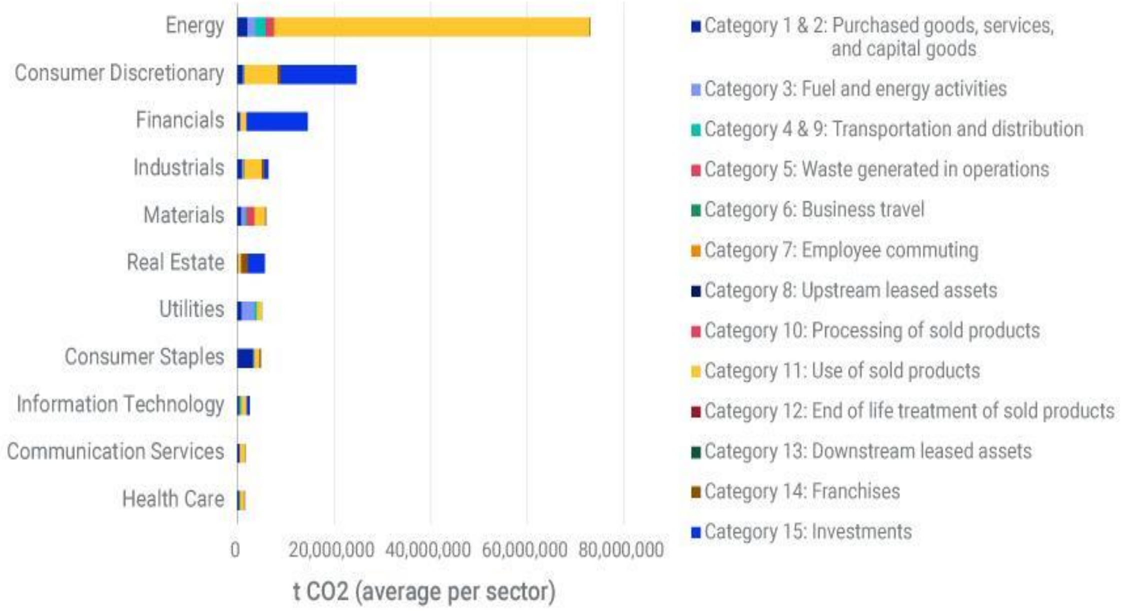
Scope 3 for O&G

Focus on category 11 and natural gas

Overview

- **Scope 3 categories:** The GHG Protocol outlines a total of 15 categories to capture a company's full value chain footprint – 8 upstream and 7 downstream.
- **Category 11:** For the oil and gas sector, around 75 percent of scope 3 emissions stem from downstream use of sold products (category 11) and 15 percent stems from upstream purchased goods and services (category 1). The remaining 10 percent is roughly equally divided into capital goods, upstream transportation and distribution, processing of sold products, and remaining relevant categories.
- **Natural gas vs oil:** A key focus of this study is natural gas, as down-stream use of sold oil declines through the switch to electric vehicles and low-carbon fuels in heavier transport (>50 percent of oil use).
- **Category 11 emission reductions:** The most optimal value chain emission outcomes for oil and gas would target the decarbonisation of product end-use. This would be achieved either by
    - **I. Decarbonising the feedstock prior to end-use**, i.e., converting natural gas into blue hydrogen with CCS, or
    - **II. Decarbonising 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.
- **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. decarbonisation 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, 2020[1]



1 = Based on constituents in the global MSCI ACWI Index as of July 2020. Source: MSCI

Why scope 3 emissions matter for the NCS
Company perspective

Increasing value and competitiveness for Norwegian oil and gas companies

- **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.
    - **Impacting indirect emissions:** positively influencing emissions outside of its own direct control can thus have significant decarbonisation 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 increasingly concerned about scope 3 emissions:** 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).
    - **Scope 3 reporting pressures increasing:** The EU Corporate Sustainability Reporting Directive will require reporting and tracking of sustainability information throughout the value chain. Further, EFRAG (European Financial Reporting Advisory Group), which will provide the standard on how to report under the CSRD, requires reporting of full scope 3 emissions – 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 decarbonisation of product end-use.
    - **Tackling indirect emissions likely key to long-term O&G industry value:** 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 and hard to abate sectors.


EUROPEAN COMMISSION

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

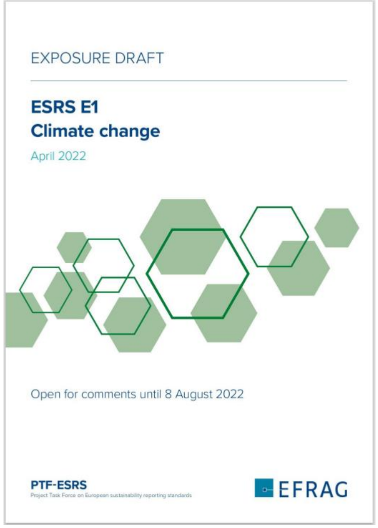
Proposal for a

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}

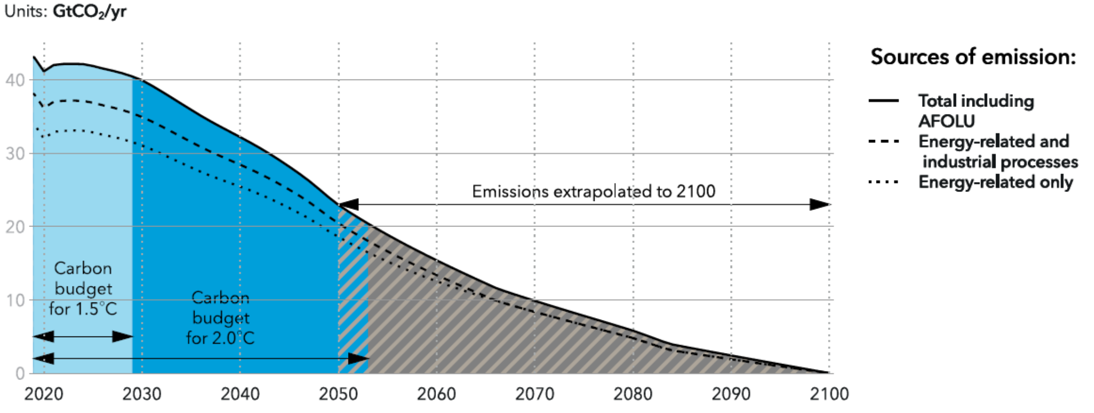


Why scope 3 emissions matter for the NCS
National perspective

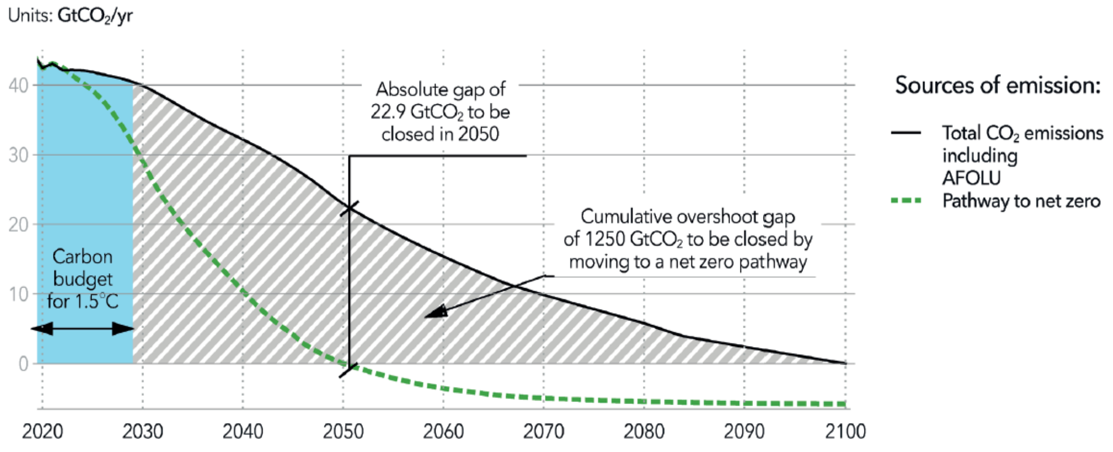
Delivering on national carbon budgets and tackling exported emissions

- **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 largely 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 decarbonise 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. The charts on the right illustrate that DNV projects a substantial gap between the current decarbonization trajectory (top chart), and the decarbonization trajectory needed for a net zero pathway (bottom chart). This may over time intensify pressure for countries to reduce their exported emissions.

Carbon emissions according to DNV's Energy Transition Outlook 2021



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



Source: DNV

Energy security and scope 3 in the REPower EU Context

Perspectives on the EU plan to eliminate reliance on Russian fossil fuels and its impact for Norway

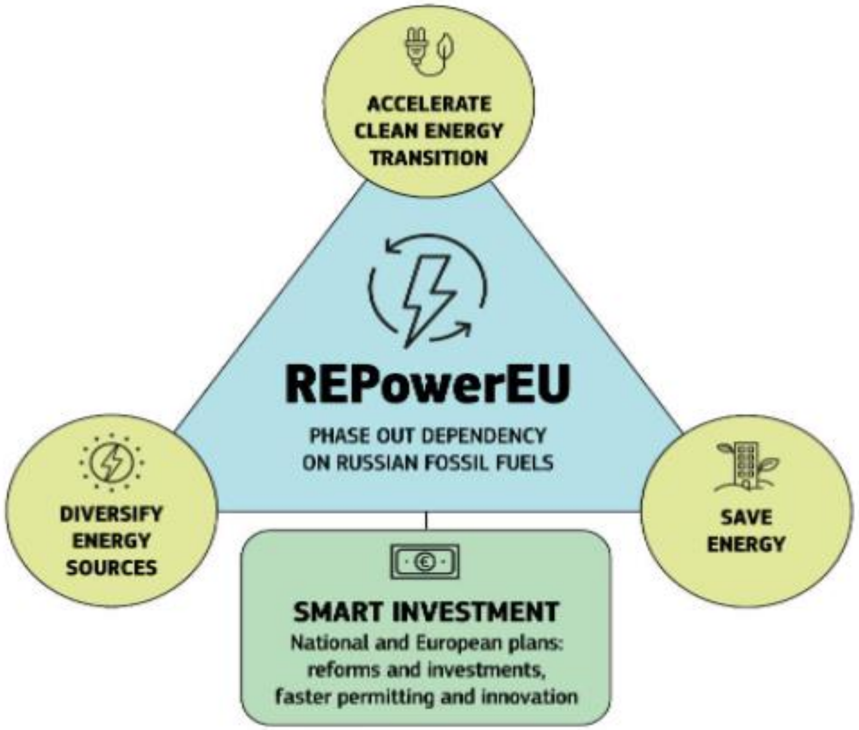
Following the Russian invasion of Ukraine on February 24th, the EU presented the REPower EU Plan – with the ultimate objective of ending the EU's dependence on Russian fossil fuels. The three key objectives of diversifying energy sources, accelerating the clean energy transition and reducing energy consumption through energy efficiency measures have key implications for the Norwegian oil and gas industry.

- **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:** The decarbonisation of exported gas would be dependent on downstream natural gas decarbonisation outside of Norwegian control, but may have Norwegian companies active in the decarbonisation, i.e., by delivering the CCS solutions.

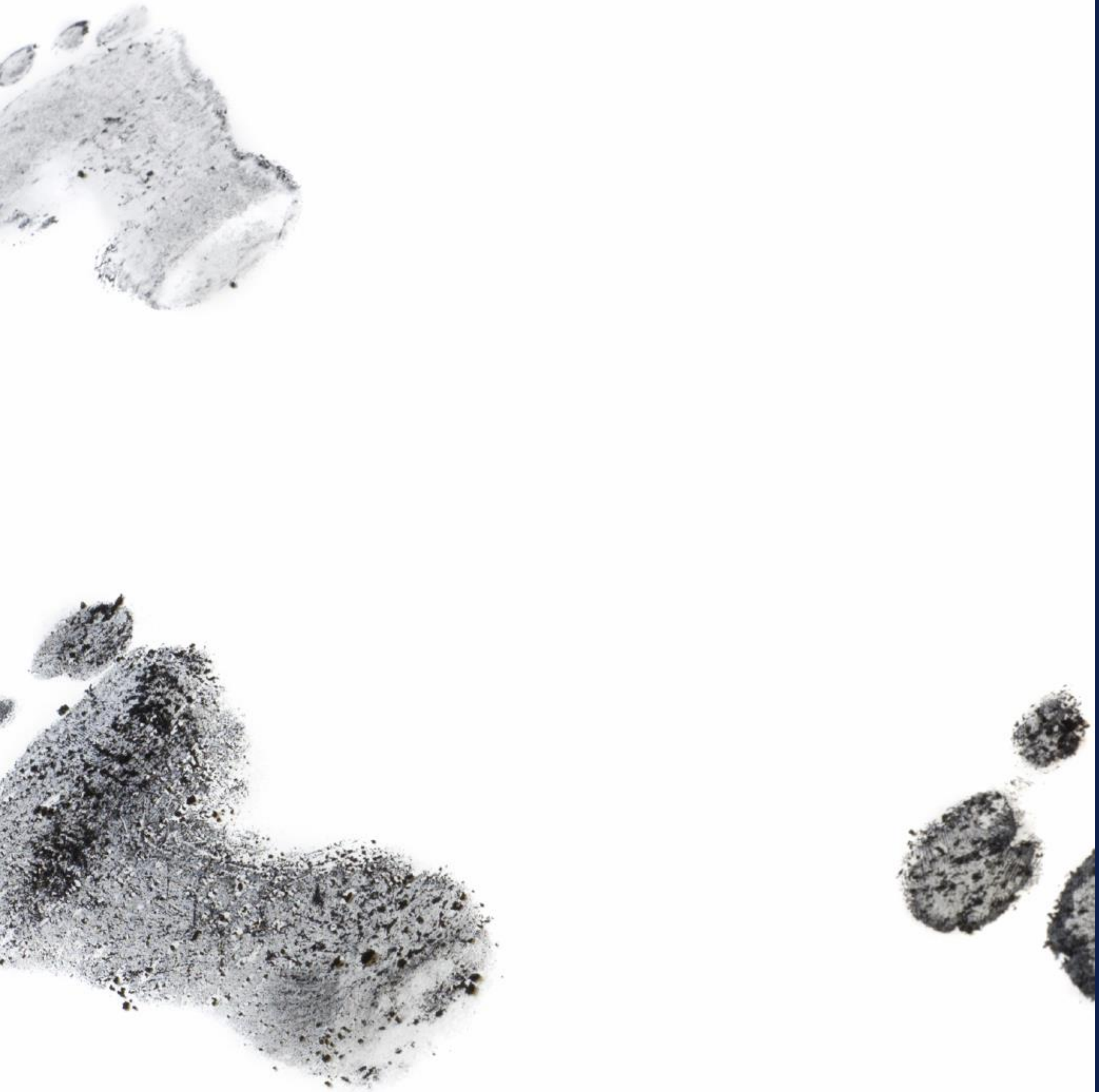
- **Efficiency - LNG cut first:** The overarching focus on reducing gas consumption will reduce gas demand over the coming decade. But as Russian gas has made up about 45 percent of EU natural gas imports over 2021 – there is still ample space for relatively cheaper Norwegian gas vis-a-vis LNG imports, even amid a significant push for reducing natural gas consumption through energy saving and efficiency measures. However, as noted in chapter 2, there is uncertainty surrounding when and how much EU energy saving measures could impact the demand for Norwegian gas which may pose a risk to long-term export demand.
    - **Scope 3 reduction angle:** Would be dependent on downstream natural gas decarbonisation outside of Norwegian control, but may have Norwegian companies active in the decarbonisation, i.e., by delivering the CCS solutions.

- **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 will reduce downstream use of sold product scope 3 emissions. This would also support longer-term export demand for low carbon fuels.

The REPower EU measures to phase out reliance on Russian fossil fuels



Source: European Union



5.2

Comparing measures:

Reducing scope 3 emissions

Less favourable — More favourable

Comparing scope 3 emission reduction measures

	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/offshore 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

Less favourable | More favourable

Comparing scope 3 emission reduction measures

	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) • Losses in energy transmission, depending on distance (2-15 %).	• Gas power generation, assuming CCGT (~40% losses) • CCS value chain adds some losses (~10-15%) • Losses in energy transmission, depending on distance (2-15 %)	• Gas power generation, assuming CCGT (~40% losses) • CCS value chain adds some losses (~10-15%) • Losses in energy transmission, depending on distance (2-15 %)	• Conversion losses from gas to hydrogen with CCS (~20-65% losses, depending on end-state of hydrogen) • Potential additional losses if hydrogen is used for power generation (~40-70% losses) • Less efficient energy transmission (30% energy content by volume 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.

Tackling use of sold products emissions

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 percent 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 measures, 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 CO_2 atlas, it is possible to store up to 80bn tonnes of CO_2 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 for 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 CO_2 on behalf of other markets.

Tackling use of sold products emissions
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 measures

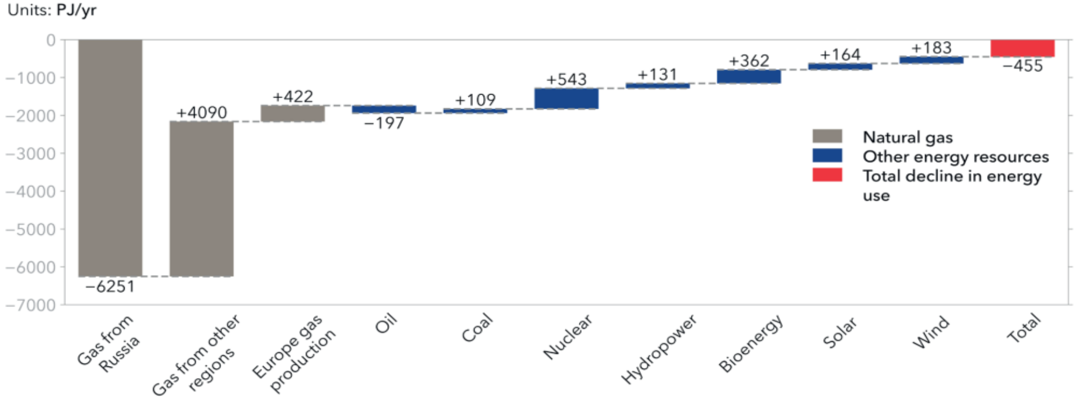
- **Higher gas prices:** Rising gas prices, exacerbated by the Russian invasion of Ukraine, could shift the narrative that blue hydrogen is a transition fuel on the way to green hydrogen and derivatives.
- **Energy security considerations:** Converting natural gas to hydrogen entails high energy conversion 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 in the short to medium term.
- **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 CO_2 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 percent 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

6. The value potential of GHG emission reduction measures for the Norwegian O&G industry

The value potential of GHG emission reduction measures

Business opportunities for the Norwegian O&G industry

The energy transition offers challenges, but also enormous business opportunities. The European energy market in 2030, 2040 and 2050 will be drastically different from today and Norway's role as energy nation will transition accordingly. The global oil and gas industry in 2050 will also be drastically different from today and the pace of transition will accelerate, regardless whether the Paris agreement is to be met. Once a real sense of urgency hits the O&G industry, the need for decarbonization solutions will be immediate.

To harvest this value potential, the Norwegian O&G industry needs to take a leadership role in Scope 1,2 and 3 decarbonization solutions for the petroleum value chain now. This will i) provide a de-risked long-term business model in a low carbon world, ii) support the pace of the required global transition to reduce GHG emissions and iii) provide strategic value. This is further discussed in the next pages, based on the bullet points below.

i) Financial

1. **Norway's O&G industry as large exporter of GHG reduction technologies**
2. **Prolonged production life and reduction of stranded assets**
3. **Continued access to capital, financing the energy transition**
4. **Norway as the long-term provider of energy security to Europe**

ii) Emissions

1. **Reduced emissions as a license to operate globally**
2. **Norwegian gas as a transition fuel for Europe**
3. **Pricing in externalities**
4. **Increased cooperation along the O&G value chain**

iii) Strategic

1. **Prolonged political support for O&G activities**
2. **Taking decarbonisation responsibility by achieving 2030 and 2050 targets**
3. **Retaining and attracting talent**
4. **Jump on the megatrend of electrification**

Financial value potential

A de-risked long-term business model in a low carbon world

Norway as the long-term provider of energy security to Europe

- The Ukrainian war, and the increased awareness of European dependence on Russian gas, provided new focus on energy security. It's evident that demand for Norwegian gas has increased short-term (up to 2025), potentially mid-term (up to 2030-2035), as indicated by the joint statement from the EU and Norway (June 22)
- However, long-term demand is uncertain. EU's strategy to reduce dependence on Russia will mean reduced gas consumption. This reduction is not matching reduced supply short to midterm, but long-term, this adds uncertainty to demand for Norwegian gas. A leading role in fossil fuel decarbonisation solutions increases the partnership and cooperation with the EU and makes Norwegian gas a more attractive option to include in EU's pathway to net zero.

Prolonged production life and reduction of stranded assets

- The oil price drop in 2020, explained by uncertainty for oil demand during the pandemic, resulted in investors placing less value on the reserves to production ratio for O&G companies. Write downs on the value of reserves at times of low oil prices resulted in large losses and provided an insight in financial performance in times of lower oil demand.
- The energy transition evolves more gradually, but the pace is not set in stone. To reduce the risks from timing the transition pace right, reducing scope 1, scope 2 and scope 3 emissions will provide a competitive advantage vs. other O&G producers, potentially extending the demand for products by pushing out other O&G producers, prolonging production life of existing Norwegian assets and reducing the risk of stranded assets. This should not be mistaken by prolonged production life of assets globally – reduced scope 3 emissions will likely require a global reduction of production

Continued access to capital, financing the energy transition

- DNV forecasts that funding new O&G activity will become more expensive in the future. Where companies might today have a cost of capital of 8 percent to O&G upstream activities, DNV expects this to increase to 12 percent in 2050. This reflects a slow trend upwards, too slow to achieve net zero targets in 2050.
- The upward trend is explained by a slight expected reduction in available capital (increased pressure for European banks and investors to have a portfolio of investments that align with Europe's climate reduction goals) and higher financial risks, i.e., what will the economic lifetime be of an oil field coming online in 2040?
- By creating integrated energy players by (i) continuously reducing the emission intensity of its O&G operations and (ii) investing in low-carbon markets, including renewable power, bioenergy, next-generation mobility, energy services, and low carbon hydrogen, the cost of capital could be lower for Norwegian companies than for more O&G pure-play competitors, helping finance the company's transition.

Norway's O&G industry as large exporter of GHG reduction technologies

- Norway's O&G industry has access to the global O&G market, governed by trade agreements and building on existing technology competence, offering opportunities to export products globally.
- Export potential can increase revenue, lower costs due to economies of scale, and provide the possibility to specialize to a much higher degree than when decarbonization solutions would only be produced for the Norwegian industry. Current observed supply constraints are an early indicator for increased demand and a need for specialization and scaling up production.
- Another value of a global market is that demand for decarbonization products will not evolve at the same pace in the different regions. Europe is likely to move first, with other regions following thereafter. The climate crisis will, sooner or later, trigger a very large demand for decarbonization solutions that can be quickly implemented and can be provided by a stable industry, like the Norwegian petroleum industry.
- The shortlisted technologies in this study, like electrification using offshore wind, hold large global potential. The technology can be scaled rapidly alongside other offshore wind build out plans.

Emissions value potential

Support the pace of the required global transition to reduce GHG emissions

Reduced emissions as a license to operate globally

- Last year, Exxonmobil placed two climate-friendly directors in its board, after an investor pushed for carbon neutrality targets, Chevron’s shareholders voted the company should reduce scope 3 emissions, and Shell was ordered by a Dutch court to cut its emissions.
- These are examples of increased engagement from investors and activists and highlight that reduced emissions are increasingly becoming a value driver.
- If the Norwegian O&G industry has the lowest CO_2e/barrel, and the gas is decarbonised downstream, it offers a low carbon value chain opportunity

Pricing in externalities

- Mandatory disclosure requirements, scope 3 emissions reporting, and a stronger focus on biodiversity and circularity are forcing companies to show tangible contributions to global goals.
- Tighter regulatory oversight of ESG is coming, especially in Europe, with the idea that this will help capital markets to financially reward companies for reducing their carbon footprints.
- Investors will increasingly price in transition risk, thereby reducing the market capitalization / equity value of companies that have direct emissions (Scope 1) and increasingly indirect emissions (Scope 3).
- The O&G industry is piloting new business models where externalities are increasingly priced in. Examples are from Shell, and Lundin. The immature market today is likely to converge to a market where such products obtain preferential treatment, and potentially (but uncertain) price premiums for such products, and therefore create new ways of adding value.

Norwegian gas as a transition fuel for Europe

- Piped Norwegian natural gas has the advantage of a relatively low life cycle emissions footprint for European end-use vis-à-vis LNG imports. This will favour Norwegian gas as a transition fuel to replace coal and Russian gas, and as an input to low-carbon fuels such as blue hydrogen/ammonia.
- The notion of natural gas as bridging fuel, i.e. an interim fuel until renewable energy solutions, should be used with caution to avoid unnecessary lock-in of fossil fuels where better alternatives exist. Therefore, the EU taxonomy complementary act includes any new or refurbished natural gas that either meets **i)** a 100gCO_2e/kWh life cycle emissions threshold, or **ii)** a number of criteria with regards to emissions intensity, while being designed to switch to renewable/and or low-carbon fuels (see also 3.6). More stringent emission intensity requirements for activities using natural gas as input will thus favour Norwegian gas.

Increased cooperation along the O&G value chain

- Building on the scope 3 value potential presented in the previous chapter for production of gas with downstream CCS, this offers a need and opportunity for increased collaboration across the full O&G value chain, from upstream to downstream.
- Collaboration on emissions can have positive wrinkle effects towards a more efficient and cost-competitive supply chain, in a time where carbon prices will increase.
- Taking responsibility outside the national borders to decarbonize shows leadership and offers increased demand for decarbonisation solutions downstream. Emissions are borderless, so a faster decarbonisation of Europe could reduce the pressure on certain Norwegian sectors where technological solutions to decarbonise might not yet be present. By tackling the GHG emission problem jointly, cross-border relationships will be improved and collaboration with the EU increase.

Strategic value potential

Being a leader in decarbonization solutions for the petroleum value chain

Prolonged political support for O&G activities

- The Norwegian oil & gas industry has, and is, enormously benefitting from generous tax support. Such support is not in line with long-standing pledges to phase out fossil-fuel subsidies.
- This is a long-term driver for reduced subsidies. However, a sector that meets up to Norway's Nationally Determined Contributions (NDC's), could expect longer political support, including financial support, than one that is not doing so.
- As an example, Denmark has cancelled its North Sea licensing rounds in 2020 in anticipation of ending oil and gas production in the North Sea by 2050. This illustrates that majority political support to end fossil fuel extraction can be found.

Taking decarbonisation responsibility by achieving 2030 and 2050 targets

- The Norwegian O&G industry will gain political and public credibility for its GHG emission reduction efforts when targets for 2030 and 2050 are set, uniformly measured and achieved.
- Cases of «green washing» in the global O&G industry is a serious risk to public perception: Rather than adapting business models to make the transition, many prefer to greenwash high-emitting activities, highlight one-off green investments and/or relocate to regions with less stringent climate policy. A Norwegian O&G industry that invests in its future by acknowledging its emissions and streamlining efforts to correctly measure and reduce emissions in line with ambitious targets, will ensure that Europe will look to Norway as a preferred supplier of O&G products. Moreover, a good sustainability record may provide companies with a higher market capitalization.

Retaining and attracting talent

- Sufficient access to skilled labour today, in 5 years, and in 20 years, require an industry with foresight. Labour is an essential ingredient to create value.
- The required technology development and obstacle mitigations for the identified low carbon solutions in this study offer a challenge that is real and a meaningful specialisation with long-term potential for new employees.
- Making resources available beyond the O&G industry towards future growth markets, that are offshore and complex, like offshore aquaculture, holds strong strategic potential and can support retention and attraction. This requires leadership now.
- Ambitious, realistic and measurable reduction of GHG emission in line with 2030 and 2050 targets may attract a higher calibre of employees and board members.

Jump on the megatrend of electrification

- Taking leadership in R&D and piloting for electrification, whether from shore or from local supply, will enable the O&G industry to develop solutions that build on the electrification megatrend.
- Norway's ambition to be a leading nation in offshore wind, with an industry that develops and builds wind energy solutions that has a competitive edge over other technologies, will need the O&G industry to succeed. The reason is that the Norwegian O&G industry has 50 years of experience with developing technologically advanced value chains and sits on world leading competence. Highly qualified engineers, professionals, researchers and universities are already in place to lead decarbonisation technology development.
- The planned build-out in Norway of 30 GW of offshore wind by 2040 offers the opportunity to create synergies by for example developing an offshore wind multi-purpose offshore grid. The result will be a deeper connection of the O&G industry to the power sector and heavy industry, sectors that will see a growing size of investments and therefore opportunities. By jumping on this trend, the Norwegian O&G industry is provided with increased future value creation.

7. Conclusions and recommendations

Charting a clear path to delivering on climate targets

There is a rising emphasis on intensifying decarbonisation efforts in order to mitigate increasingly evident global warming impacts and meet looming 2030 targets to reduce emissions aligned with national, regional and Paris commitments. For Norway, in the near-term this entails reducing GHG emission by at least 50% and towards 55% by 2030 compared to 1990 levels – and in the long-term to be a low emission society by 2050. As of end-2021, Norway had only reduced emissions by 4.5% compared to 1990 levels.

- **Charting a realistic path to target delivery:** Comprising a large share of Norwegian emissions, the Norwegian oil and gas industry has a notable responsibility in enabling Norway to meet its decarbonisation targets. As part of the temporary changes to the Petroleum Tax Act in 2020, the Parliament set an absolute target of 50 percent scope 1 emission reductions by 2030 compared to 2005 levels for the industry. DNV has through this study assessed the scope for implementing a variety of measures that can ensure that the sector can deliver on these targets. Notably, this study has sought to describe realistic ways for the NCS to meet its target, by identifying and prioritising a number of measures that can supplement existing efforts to meet 2030 targets and beyond.
- **Targeting the right emissions:** The main objective for this study has been to assess how scope 1 emissions from the various actors at the NCS can be reduced, cumulatively enabling the sector to meet its GHG emission reduction commitments. With gas turbines making up 83% of scope 1 NCS emissions, and eight O&G installations making up over 50% of total NCS emissions, it is clear that measures must target emission stemming from this equipment and sources to deliver on 2030 targets.
- **Prioritising the right measures:** A total of 12 measures were assessed with the above in mind, taking into account GHG reduction potential, maturity, application scope, scaling potential, development/implementation obstacles as well as industry opportunities and synergies. These included various electrification approaches, gas-fired power with CCS, compact top-side CCS, hydrogen and hydrogen derived fuels for power generation, various approaches to energy efficiency through reservoir management, optimized gas turbines and geothermal energy.
- **Implementing the right measures:** Following an assessment of the merits of the above measures, this study argues that the most promising measures are **(i & ii)** coordinated or individual electrification with power from shore, **(iii)** electrification through local supply from offshore wind **(iv)** gas-fired power with CCS and **(v)** energy efficiency through water management for reservoirs.

Electrification
Key takeaways

Power from shore (coordinated and individual approach)

- Electrification of O&G platforms through power from shore is considered a key measure to achieving the GHG emissions reduction targets, with an estimated total potential of 4.5 million tonnes CO_2e emission reduction per year in 2030. The preferred network design solution depends on several factors, and two fundamentally different options exist: an individual and a coordinated design approach.
- **Individual design approach**: Each platform is connected to the onshore grid via a dedicated radial connection. This design offers simplicity and requires less coordination but can result in an overall sub-optimal network design and higher costs to ensure reliability of supply.
- **Coordinated design approach**: Multiple platforms are connected to one offshore hub (shared substation) before being further connected to the onshore grid through a radial connection. Although this is a more complex design requiring a high degree of coordination between stakeholders with different ownerships in licenses and assets, significant economics of scale and a more optimal network design can be achieved.
- The main obstacles are related to distances from shore and weight and space limitations for DC equipment, high cost and potential loss of revenue due to downtime during retrofitting, access to sufficient power from shore, as well as long lead times. For a coordinated approach, differences in remaining lifetime of assets and frequency levels are also important challenges.
- Several mitigations exist on technical obstacles such as subsea or more compact equipment. On more political and societal obstacles, important mitigations include speeding up decision-making processes, establishing predictable policies and frameworks to give clear investment signals for offshore electrification, and building out new renewables and grid capacity.
- Although electrification of platforms through power from shore is considered a key measure, anticipated reduction in power surplus and increased grid constraints, historically high power prices and continued domestic bidding zone price gaps, in additional to a challenging geopolitical landscape has caused a heated political debate on how the power grid should be developed and whether the NCS should be electrified from shore. This brings uncertainty to developers and operators. Long-term and predictable policies are crucial in reducing risks.

Local supply from offshore wind

- Norway has excellent offshore wind resources and should act on the opportunity to take part in the global megatrend of offshore wind development.
- O&G platforms could be supplied with electricity from offshore wind turbines without a connection to shore. As such, this solution can help provide electrical power to installations in areas with long distances to shore or where the onshore grid is constrained. However, this would require a back-up solution to ensure consistent power supply.
- Offshore wind can be either bottom fixed or floating, however the water depth on the NCS suggests floating solutions are largely required. Floating wind is approaching large scale and commerciality, with only a few years before we will see the large multi unit-projects. Innovation and developments are still needed in order to reduce costs.
- According to KonKraft, electrification through local supply from offshore wind is estimated to have a potential of 0.4 million tonnes of CO_2e emission reductions per year in 2030 (based on reported measures). However, the potential can be much higher, especially in areas where electrification from shore is challenging. Installing a wind farm could also be an intermediate solutions until a cable from shore is in place.
- Supply chain constraints, long lead times and insufficient policies are key obstacles for implementing offshore wind. In order to ensure predictability, it is important to speed up decision-making processes, develop local supply chains, ensure sufficient support mechanisms and coordinate developments across industries.
- Combining power from shore with offshore wind can ensure security of supply as well as power supplied to shore during surplus hours. Technically, the power cable should be able to export back to the shore without major adjustment.

Key advantages and opportunities

- Electrification increases the energy efficiency, resulting in less energy use overall. Moreover, the operational costs can be reduced due to lower cost of CO_2 tax and fuel. Electrification of offshore assets will also have the indirect benefit of reduced noise and thereby improved working environment offshore.
- The released natural gas can be exported to Europe and used in onshore gas power plants with higher efficiencies. This will both increase export revenues for Norway while at the same time helping Europe to become independent of Russian gas.
- A combination of building out an offshore grid with power form shore and offshore wind farms to supply installations on the NCS has several industrial opportunities: developing floating offshore wind industry in Norway; ensuring security of supply to the installations and power supply to the onshore grid during surplus hours; facilitate a future meshed offshore grid that can connect to the planned North Sea offshore grid long-term; facilitate an offshore industry long-term when O&G assets are decommissioned.
- Concepts of combining offshore wind with existing power-from-shore concepts, e.g. Utsira High or Troll West, can be especially relevant, as investments in transmission supply are already paid for. This can reduce OPEX from power purchases, limit total power losses through the transmission cables, while also give rise to fast-track medium-sized wind farms that could be important stepping stones to cost-efficient large-scale wind farms in the early 2030’s. An important obstacle that should be further investigated is the uncertainty in regulatory frameworks for delivering power to shore under the Petroleum Tax Act.

Gas-fired power hub with CCS
Key takeaways

Gas-fired power hub with CCS

- A gas-fired power plant with CCS provides electricity through running gas turbines while capturing and storing the CO_2. The plant could be located both onshore or offshore, and the preferred solution will depend on several factors (costs, available infrastructure, permits and regulation, political and societal acceptance, amongst others) which will depend on the given case.
- Several concepts have been developed, but none has been constructed to date. Use of qualified equipment as far as possible will be important in order to reduce risk and uncertainty.
- An offshore power hub is a stand-alone solution independent of power from shore. As such, it can help provide electrical power to installations in areas with limited onshore infrastructure or long distances to shore. In the long term, the power hub could be connected to shore to supply additional power and balancing capabilities to the onshore grid. An onshore gas-fired power plant is in principle the same concept as power from shore but could help increase power production onshore.
- DNV's analysis show that offshore power hubs located in three areas could reduce emissions by 4.5 million tonnes CO_2e per year in 2030 (around 35 percent total reduction from 2020 levels), if all required infrastructure for transport and storage of CO_2 is in place.
- A power hub requires many operators and stakeholders to agree on a solution and distribute cost and risk, so early dialogue and cooperation is key for getting this measure started.
- The solution could help further develop the Norwegian CCS supply chain, cementing Norway as a global leader in CCS activities and commercial CCS value chains.


Photo: DNV/DGS AS

Reservoir water management
Key takeaways

Energy efficiency through reservoir water management

- With increasing energy cost and CO_2 price, the incentive for promoting new and improved technologies will increase. Co-operation between operators, vendors and expert areas is key to promote technology developments and remove silos.
- The potential for energy optimization for water management stems from topside with optimal use of water pumps and compressors, subsea or downhole water treatment with separation and reinjection of water, and control of well inflow by smart completion. Choice of solution and resulting GHG emission potential is highly case sensitive, and the key to success for water management will be good reservoir understanding in combination with efficient use of data and technology.
- The costs of new water displacement technologies are high. Standardization of technologies will bring down costs and risks, as will strengthening regulatory requirements to apply new technology in license and PDO-processes.
- Several possibilities are available to limit water inflow and the energy used for water management.
- Tail-end production with high water-cut wells is energy intensive. For the fields with the highest water-cut, shut-down of the fields might be a more economically viable solution taking a long term industry perspective. If the industry is not progressing to meet GHG emission reduction targets, the government could respond by increasing the CO_2 taxes and thereby reduce the long term value of all O&G industry production.

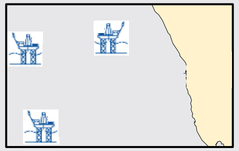
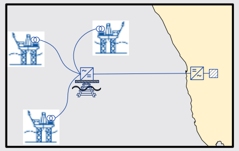
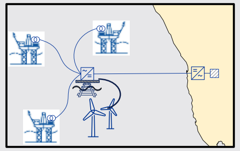
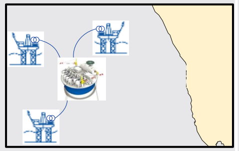
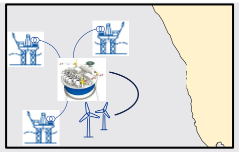
Case study on selected measures
Main results

A high-level case study on a full electrification of three platforms with 85 MW power demand each located close to each other was performed, comparing a few selected measures. The following results can be observed:

- **The most expensive option measured in LCOE is not doing anything** (Case 0). This is due to the high CO_2 tax and fuel cost (the alternative value of exporting natural gas).
- All alternative cases will result in energy being used more efficiently, with the power from shore cases being the most energy efficient, as well as more gas being available for export to Europe.
- **Case 1 (Power from shore through a coordinated approach) has the lowest LCOE and abatement cost** due to lower investment costs compared to the alternatives. However, it must be noted that this does not include investment costs for upgrading the grid capacity onshore, which might be needed depending on the location of the platforms.
- Case 2 (Gas-fired power hub offshore with CCS) has a higher LCOE than power from shore, however is a **stand-alone solution and thus not dependent on the onshore grid**. Note that a case with gas-fired power hub onshore with CCS has not been assessed in this case study, as the concept is similar to electrification through power from shore.
- **Introducing floating offshore wind helps reduce the OPEX** as it either reduces the cost of purchasing electricity (Case 1.1.) or reduces the cost of fuel and CO_2 tax (Case 2.2). However, the LCOE and abatement cost is increased due to higher investment costs.
- All cases have an abatement cost exceeding the expected CO_2 price in 2030. However, it is not unreasonable to expect a further increase in the CO_2 tax beyond 2000 NOK/tonne CO_2.
- It is important to note that this case study is **high-level** and that the cost of various measures are **extremely case dependent.** Moreover, potential project specific cost factors have been excluded, such as downtime for retrofitting and associated postponed revenue*. The following slide present **sensitivity analysis** to show how the results are affected by a change in the assumptions.

Results using the base case assumptions. Sensitivity analysis on key parameters are presented in the following slide

Key assumptions are presented in Section 4. Both the LCOE and abatement cost are calculated based on discounted flows (costs, energy and CO_2)

	0: Do nothing	1: Power from shore (coordinated approach)	1.1: Floating wind turbines and power from shore	2. Gas-fired power hub offshore with CCS	2.1: Floating wind turbines and gas-fired power hub offshore with CCS
Conceptual illustration					
Short description	Running traditional gas-fired turbines without modifications.	250 MW HVDC cable from shore with dedicated jacket for DC equipment, AC supply to platforms.	Same as case 1 including floating wind turbines with installed capacity of 85 MW.	Sevan floater 250 MW power hub as stand-alone solution located with AC supply to platforms.	Same as case 2 including floating wind turbines with installed capacity of 85 MW.
Power purchased from shore [TWh/yr]	-	1.10	0.75	-	-
Power produced offshore [TWh/yr]	1.10	-	0.35	1.10	1.10
Fuel consumption [TWh/yr]	3.65	-	-	2.00	1.40
CO_2 emitted [tonne/yr]	722,700	-	-	39,400	27,100
CAPEX [MNOK]	N/A	12,780	15,580	16,760	19,560
O&M costs [MNOK/yr]	80	120	155	80	110
CO_2 tax [MNOK/yr]	1,455	-	0	80	55
Fuel/electricity cost [MNOK/yr]	790	580	400	430	300
Abatement cost [NOK/ tonne CO_2 abated]	**N/A**	**2,680**	**2,786**	**3,271**	**3,326**
LCOE [NOK/kWh]	**2.41**	**1.77**	**1.84**	**2.04**	**2.11**

*The required downtime for retrofitting is highly project specific. Electrification of assets can be completed within normal maintenance stops, depending on the technical basis and careful planning. In other cases, additional downtime will be required.

DNV

Case study on selected measures

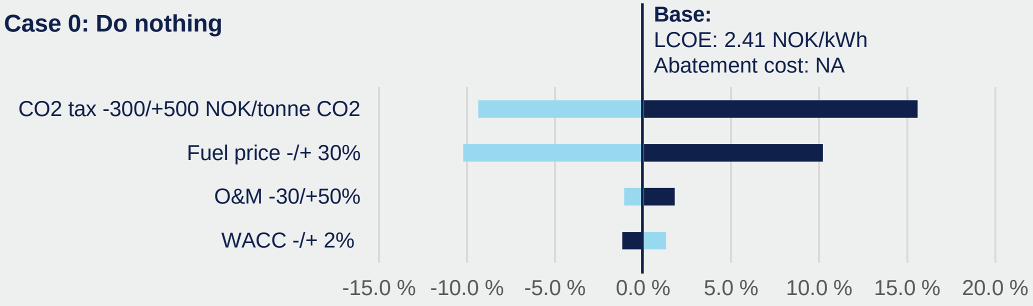
Sensitivity analysis

Sensitivity analysis have been performed to assess the uncertainty in the results as well as map out which parameters have the highest effect on the results. As no uncertainty has been applied to the power production or the CO_2 abated, the results shown below (percentage change) apply to both the LCOE and the abatement cost.

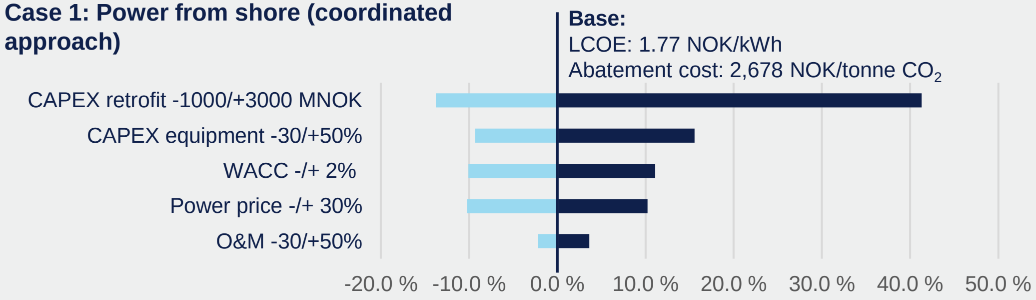
The analysis show that the CAPEX for retrofitting of the platforms have the highest impact (positive and negative) for most cases. This is due to the fact that the cost of retrofitting is extremely case dependent and as such the uncertainty ranges are high.

Even with a low retrofitting cost, the abatement cost is higher than the CO_2 price for all cases. Although not assessed here, the abatement cost could be lower than the CO_2 price in the event of several assumptions being reduced simultaneously (e.g. both a lower CAPEX of retrofitting and a lower CAPEX on equipment). Moreover, it is not unreasonable to expect a further increase in the CO_2 tax beyond 2000 NOK/tonne CO_2. For business as usual (the "do nothing" case), the CO_2 tax and fuel price have the highest impact on the results. Further details can be found in Section 4.

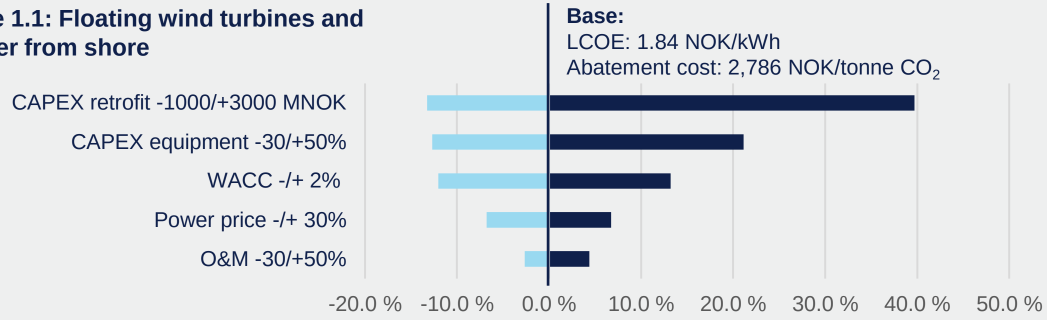
Case 0: Do nothing



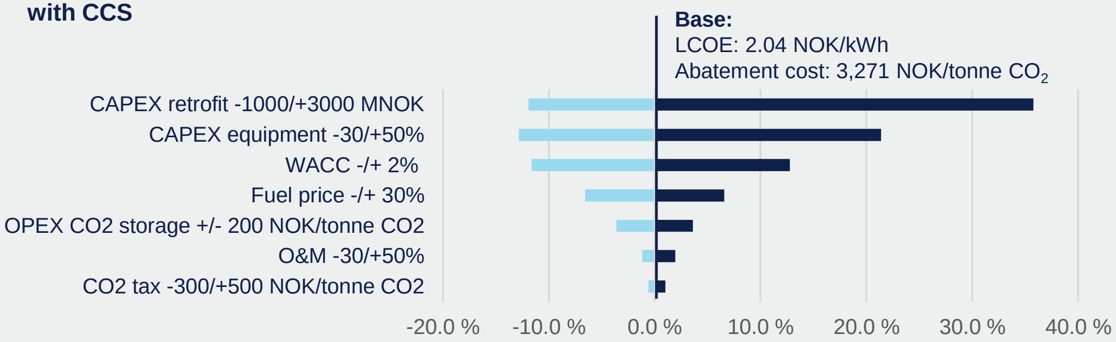
Case 1: Power from shore (coordinated approach)



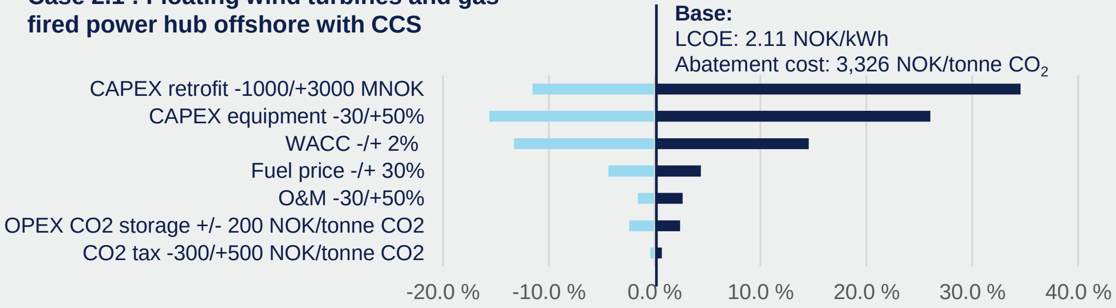
Case 1.1: Floating wind turbines and power from shore



Case 2: Gas-fired power hub offshore with CCS



Case 2.1 : Floating wind turbines and gas-fired power hub offshore with CCS



Scope 3 emission reductions increasingly important, with large value potential for Norwegian O&G industry

- **Scope 3 reporting pressures ramping up:** Oil and gas companies increasingly are expected to report on scope 3 emissions and include them in decarbonisation targets, to capture full 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", according to the GHG Protocol. The EU Corporate Sustainability Reporting Directive will require reporting and tracking of scope 3 emissions, while stakeholders ranging from investors to NGOs expect companies to report on scope 3 emissions and develop strategies on how to reduce them.
- **Safeguarding value and competitiveness:** Devising ways to reduce scope 3 emissions for Norwegian O&G companies will become a key to the long-term competitiveness and value of the sector. Scope 3 emissions can be reduced by i.e., setting supplier requirements, decarbonising fuels upstream or downstream decarbonisation (i.e., converting natural gas to blue hydrogen or generating natural gas-fired power with CCS). Ensuring the long-term value of Norwegian O&G companies will thus likely depend on sufficiently ambitious scope 3 emission reduction targets and the credibility of strategies.
- **Tackling use of sold products emissions is key to reducing scope 3 footprint:** Around 75% of scope 3 emissions from the O&G sector stem from emissions from the use of sold products (category 11 in the GHG Protocol). This is also where investors assess the main transition risk of their oil and gas company exposure to lie, and as they look to reduce such risks, working with the decarbonisation of fuels and their use is a key element for the O&G sector to retain competitive financing over time. The focus is on natural gas, as most of the reduction from use of oil will come from a reduced demand due to alternatives (such as electrification of transport).
- **Scope 3 should also be a concern for Norway:** Nation-states have shown little appetite to take responsibility for scope 3 emissions to date, but as international carbon budgets dwindle fast pressures could increase. 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, the pressure on Norway as an exporter of emissions may increase accordingly. By decarbonizing fossil fuels upstream (in Norway) or supplying CCS equipment and expertise downstream (internationally) Norway will take more responsibility for reducing exported emissions and be on the right side of this narrative.
- **REPower EU and scope 3 emissions:** Norway will be a key provider of natural gas to the EU and aiding the diversification away from Russian gas. This reduces the near-to-mid term attractiveness of exporting decarbonized natural gas in the form of blue hydrogen to Europe, as the energy losses in its conversion and reduced energy shipped (by pipeline) are negative energy security factors. This bolsters the argument for decarbonizing the natural gas downstream instead. However, over time, there is a risk that energy efficiency gains in Europe also eats into Norwegian gas exports, while low-carbon hydrogen demand in the region grows. A one-sided focus on exporting natural gas may lead to Norway not moving early enough to establish competitive hydrogen value chains. Further, this may ultimately also lead to Norway being less in control of the scope 3 emission reduction narrative.
- **Natural gas power with CCS – Maximizing gas energy security impact:** Gas power with CCS could contribute substantially to reduce scope 3 emissions from Norwegian gas, either through deployment within or outside Norway. Within Norway, the main benefits would be the scope 1 emission reductions for oil and gas operators, an increased ownership for Norway in reducing emissions from produced natural gas, the potential for electrification of industry and NCS, combined with the creation of a CCS value chain and jobs. Outside of Norway, the main benefits are reduced losses from energy transmission – key for European energy security – as well as relatively higher near-term export revenue from maximizing gas exports. Outside of Norway, positioning Norwegian companies to take part in a European CCS value chain will be key to maximizing the value for Norway and the O&G sector and documenting ownership of scope 3 GHG emission reduction efforts.
- **Blue hydrogen and hydrogen derivatives – setting the stage for new industry:** Blue hydrogen and hydrogen derivatives would create value by decarbonizing fuel/feedstock upstream – enabling Norway to take firm ownership of scope 3 decarbonization efforts and would support the establishment of new hydrogen and CCS industry. That said, energy losses from conversion and transmission would negatively impact the amount of energy shipped to Europe, which could negatively impact energy security imperatives in the near-to-medium term.

DNV

Norwegian O&G industry can harvest the value potential of GHG emission reduction measures

The energy transition offers challenges, but also enormous business opportunities. To harvest the value potential of GHG emission reduction measures, the Norwegian O&G industry needs to take a leadership role in Scope 1, 2 and 3 decarbonisation solutions for the petroleum value chain now. This will i) provide a de-risked long-term business model in a low carbon world, ii) support the pace of the required global transition to reduce GHG emissions and iii) provide strategic value.

Financial value potential: A de-risked long-term business model in a low carbon world

1. **Norway's O&G industry as large exporter of GHG emission reduction technologies:** With already established access to global O&G markets, the Norwegian O&G industry is in a good position to export decarbonisation technologies and benefit of a large expected global potential.
2. **Prolonged production life and reduction of stranded assets:** Reducing GHG emissions will provide a competitive advantage vs. other O&G producers as Norwegian O&G producers can offer a more attractive product, thereby prolonging production life of existing Norwegian assets and reducing the risk of stranded assets.
3. **Continued access to capital, financing the energy transition:** Creating integrated energy players by (i) continuously reducing the emission intensity of its O&G operations and (ii) investing in low-carbon markets, the cost of capital could be lower for Norwegian companies than for more O&G pure-play competitors, helping finance the company's transition.
4. **Norway as the long-term provider of energy security to Europe:** Long-term demand for natural gas is uncertain. A leading role in fossil fuel decarbonisation solutions increases the partnership and cooperation with the EU and makes Norwegian gas a more attractive option to include in EU's pathway to net zero.

Emissions value potential: Support the pace of the required global transition to reduce GHG emissions

1. **Reduced emissions as a license to operate globally:** Recent examples of increased engagement from investors and activists highlight that reduced emissions are increasingly becoming a value driver. If the Norwegian O&G industry has the lowest CO_2e/barrel, and the gas is decarbonised downstream, it offers a low carbon value chain opportunity.
2. **Norwegian gas as a transition fuel for Europe:** Piped Norwegian natural gas has the advantage of relatively low life cycle emissions for European end-use vis-à-vis LNG imports. This will favour Norwegian gas as a transition fuel to replace coal and Russian gas and as an input to low-carbon fuels such as blue hydrogen/ammonia, as it is more likely to meet the gradually tightening requirements for natural gas to be EU taxonomy aligned.
3. **Pricing in externalities:** Mandatory disclosure requirements and scope 3 emissions reporting are forcing companies to show tangible contributions to global goals, and investors are increasingly pricing in transition risks. Products that can document such contributions will likely obtain preferential treatment and potential premiums in the market, creating new ways of adding value.
4. **Increased cooperation along the O&G value chain:** The scope 3 value potential offers a need and opportunity for increased collaboration across the full O&G value chain, from upstream to downstream and across borders.

Strategic value potential: Being a leader in decarbonisation solutions for the petroleum value chain

1. **Prolonged political support for O&G activities:** A sector that meets up to Norway's GHG emission reduction targets could expect longer political support, including financial support, than one that is not doing so.
2. **Taking decarbonisation responsibility by achieving 2030 and 2050 targets:** Cases of «green washing» in the global O&G industry is a serious risk to public perception. A Norwegian O&G industry that invests in its future by acknowledging its emissions and streamlining efforts to correctly measure and reduce them in line with ambitious targets, will ensure that Europe will look to Norway as a preferred supplier of O&G products.
3. **Retaining and attracting talent:** Labour is an essential ingredient in creating value, and sufficient access to skilled labour will require an industry with foresight. Ambitious, realistic and measurable reduction of GHG emission in line with 2030 and 2050 targets may attract a higher calibre of employees and board members.
4. **Jump on the megatrend of electrification:** The planned build-out of 30 GW offshore wind offers an opportunity to create synergies by e.g. developing a multi-purpose offshore grid. The result will be a deeper connection of the O&G industry to the power sector and heavy industry, sectors that will see a growing size of investments and therefore opportunities. By jumping on this trend, the Norwegian O&G industry is provided with increased future value creation.

What does it take?

Identifying actions that could help acceleration

- **The technologies exist but costs are still high:** The technologies to reduce GHG emissions by 50 percent in 2030 – and beyond – exist. However, the costs are still high and both scaling and further developments are needed. Financial instruments to support implementation, technology qualification and R&D could help de-risking and reduce technology cost.
  - As mentioned by KonKraft, examples of financial instruments could be: contracts for difference, as seen in the UK for offshore wind; establishing a CO_2 fund (where the increase in the CO_2 tax is earmarked for funding decarbonisation measures and developing new offshore industries); continuing the NO_x-fund; and strengthening the mandate of Enova and R&D programmes (e.g. Petromaks 2, Demo 2000, Climit) and centres (e.g. The Petrocenters and the LowEmission Centre)
- **Predictable and long-term policies help scaling and implementation:** The current political climate and debate on electrification of the NCS brings uncertainty. As cancellation or delay in planned power-from-shore projects will make it difficult to reach the 2030 targets, long-term and predictable policies are crucial in reducing risks.
  - The 30 GW target for development of offshore wind is an important first step in ensuring a large-scale development of offshore wind in Norway. To reduce uncertainty and risk, authorities should be clear on a step-wise roadmap for how the targets can be reached and start opening new areas for offshore wind.
  - Norway should increase its ambitions on development and implementation of clean technologies to position Norwegian industry and ensure a competitive advantage.
- **More robust frameworks and supporting measures can facilitate acceleration:** A robust regulatory framework needs to be in place to support strong deployment and provide long-term investment signals.
  - Robust frameworks for offshore wind development and clarity in basis for competition need to be in place to support strong deployment and provide long-term investment signals.
  - Clarity is needed in tax regimes for cross-over license areas between new industry (such as offshore wind or power hubs) and O&G assets, and how connections to the grid would impact this.
- **Solutions that enable a speedy transition:** Given current lead times on technologies as well as lengthy regulatory processes, the industry needs to **act now** in order to reach the targets in 2030. However, it is important to not lock in sub-optimal solutions for the long term.
  - Given the time needed for license and application processes, project development, as well as lead time of equipment, projects that aim to be operational in 2030 should conclude the feasibility stage gate (DG1) **before end of 2023**.
  - Both for developing new renewable and grid capacity, license and application processes should be reviewed and the capacity of proceedings should be strengthened. The EU has proposed measures to speed up the approval and development process of new renewable capacity, such as "go-to-zones". As part of the EEA, Norway might be covered by this fast track permitting plan.
  - For an offshore grid build-out from shore, a short-term solution could be to start with radial connections that can later build into an offshore grid, similar to how the onshore grid has been built historically.
  - For CCS, new storage sites could be developed in parallel, and more license areas could be allocated. KonKraft also suggest establishing concrete targets for how much CO_2 should be stored on the NCS to ensure CCS becomes a commercial industry.
- **Strengthening measures to accelerate action:** Progress in reaching the emissions reduction targets should be closely monitored. If progress is lagging, support mechanisms can be combined with strengthening measures that increase the cost of emissions to accelerate action, in the form of higher CO_2 taxes or punitive measures. Such measures would ultimately reduce the long-term value of all O&G production and should be evaluated in light of both the energy transition and the current energy security landscape.
- **Cooperation can help optimise solutions and bring down overall costs:** Solving the issues at hand before 2030 requires cooperation between license partners and operators. Although more complex than individual solutions, this helps ensure a more optimal overall solution with lower overall costs. Good dialogue and simultaneity is key, as is data sharing to ensure transparency.
  - A coordinated approach – either an offshore power hub, large offshore wind farm or power from shore – can lay the foundation for a future meshed offshore grid that increases redundancy as well as new offshore industries in the longer term. KonKraft suggests Norwegian authorities should take an active role in EU's work with development of frameworks for hybrid projects and the future masked offshore grid in the North Sea.
- **Create a strategy for the short- and long term:** When assessing solutions to decarbonise the petroleum value chain, it is important to think both short- and long-term. This means building a strategy that supports both decarbonisation targets towards 2030 while at the same time laying the foundation for transitioning from oil and gas revenue dependency into low-carbon energy carriers and new offshore industries, such as offshore wind and hydrogen production.

Appendix A: Introduction to scope 1, 2 and 3 emissions

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 decarbonisation 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.

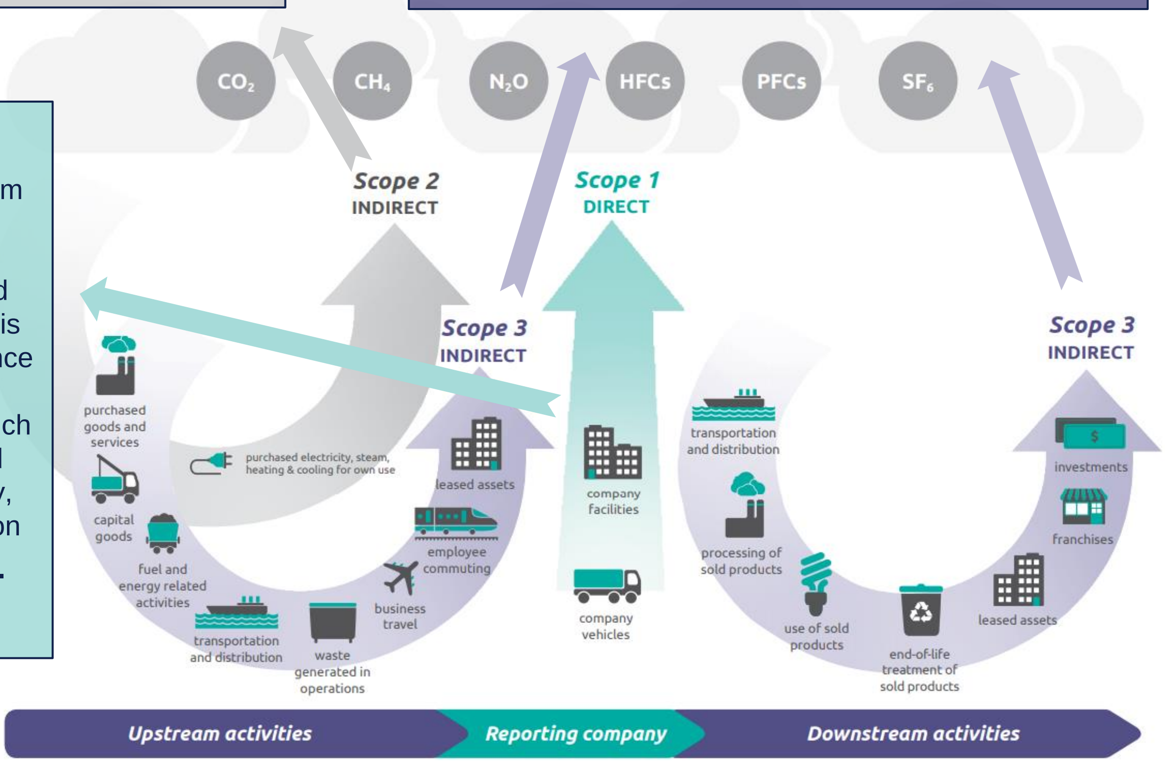


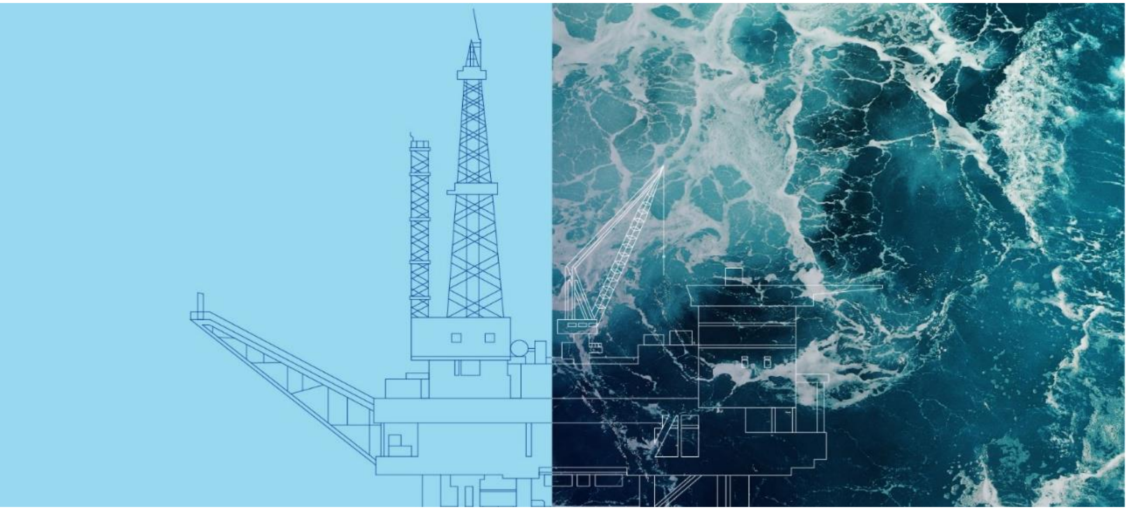
Figure: GHG Protocol

DNV

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 decarbonise value chains, all companies involved in the relevant value chain must reduce their own scope 1 emissions.
- Based on this logic, strict decarbonisation requirements for electricity generators would reduce the scope 2 emissions for all companies buying electricity. Shipping decarbonisation 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 necessary in order to meet the target of limiting climate warming to 1.5 degrees.



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

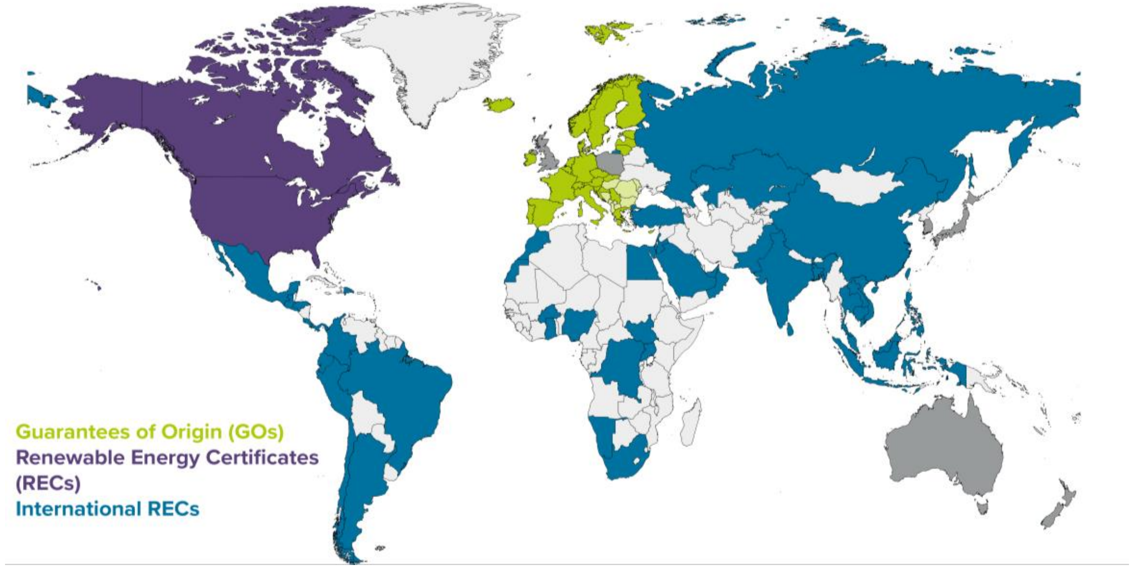


Figure: ECOHZ

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 negligible scope 1 emissions could source services, goods and materials from a more polluting upstream supply chain, leading to relatively high scope 3 emissions. Similarly, independent of the level of scope 1 emissions from production activities, oil and gas companies 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 percent 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 decarbonisation 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

DNV

Appendix B: Electrification in Norway backdrop

The debate on electrification of the NCS is intensifying

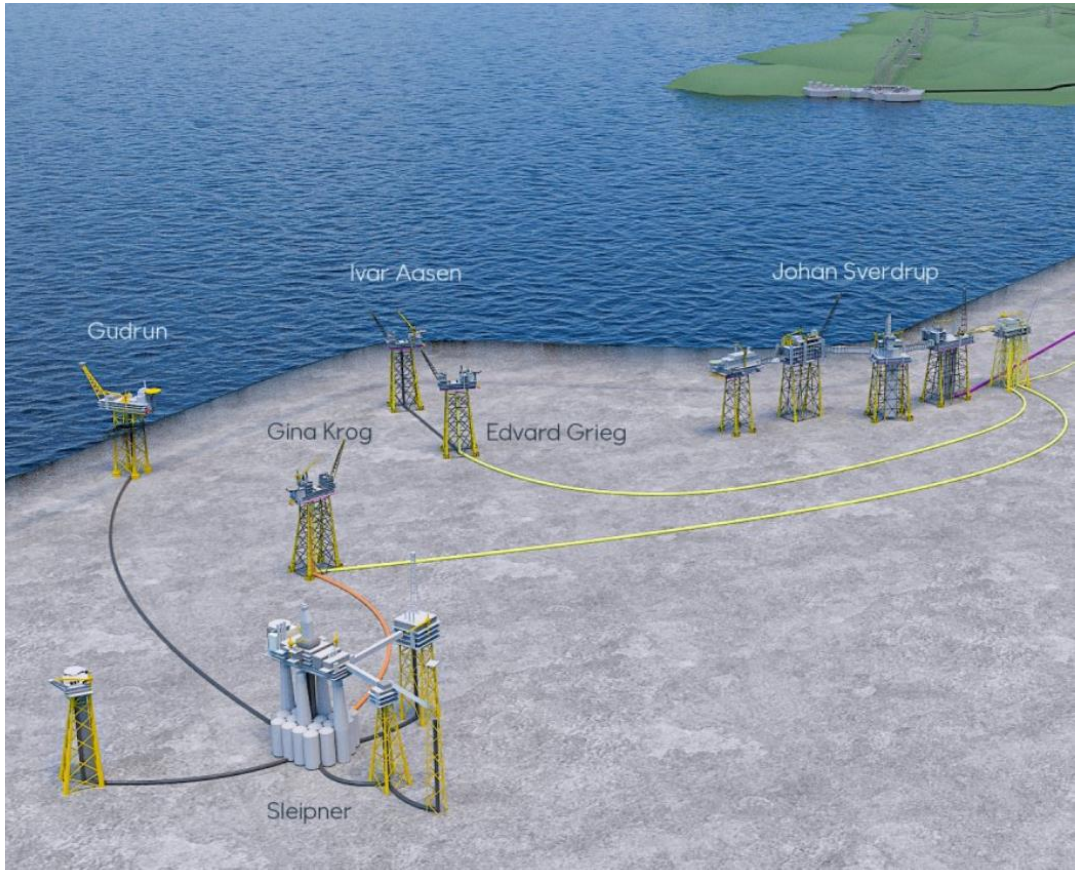


Illustration: Electrification of Utsirahøyden (Equinor)

- Electrification of the NCS has long been considered as crucial and a self-evident measure in order to reach Norway's 2030 climate goals.
- Extensive electrification plans and little new electricity production in the pipeline is causing a reduction in the historical surplus of electricity. With increasing electricity prices and the war in Ukraine, the debate on how the available electricity is best employed has emerged. The debate includes questions such as:
  - **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 that the most valuable uses, from a societal perspective, are prioritised.
  - **How will electrification of the NCS influence the regular electricity consumer?** Electrification from shore will increase the power demand from the grid, influencing the power prices.
  - **What is the lifetime of the projects that use the limited electric resources?** Several fields on the NCS are approaching tail production in the coming years, and the connected installations are often old with equipment not suited for electrification. Investing in the required infrastructure for electrification on these installations is both a socio- and business economic question.

Several elements influence electrification of the NCS

- 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 request it.** However, the customer has to pay for any necessary grid expansions, and any new major grid investment project needs to receive a licence from the government in order to be realised.

- 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.

- 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.

- 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 gives more competition for scarce resources leading to higher prices and potential public and political resistance.

- For NCS-electrification projects, it could be relevant **where the O&G platforms are connected to the grid.** There is a significant north/south difference in available capacity (and resulting power prices) that is expected to continue in the coming years.

- Concrete plans to connect to or **cooperate with new renewable/decarbonisation industries** such as offshore wind, hydrogen production, CCS etc, will reduce climate risk and could extending the lifetime of the O&G platforms.

- **Higher EU ETS prices and CO_2-prices** increases the economic incentives for electrification but can also make alternative solutions more viable.

European and Norwegian power markets will see higher and more variable power prices

The European and Norwegian electricity markets are in constant development. **Current trends that influence the markets include:**

- Stricter 2030 climate goals and higher CO_2 prices, affecting, amongst others, the power price.
- Uncertain and volatile gas and CO_2-prices due to the war in Ukraine and other geopolitical developments.
- Large volumes of wind (offshore and onshore) and solar production expected in Europe as technology prices are coming down, affecting the power price and increasing price volatility. Expected less impact of dry vs. wet years and night vs. day as compared to today's situation, a changed impact of seasonality, and an increased impact of high. vs. low wind and solar ration
- Increasing interconnectivity between European countries affecting the power price and volatility. However, the common market has linked the price zones for many years, i.e. the new interconnectors are only responsible for a few percentage of the total electricity price increase in Norway.

In Norway, electrification trends are expected to dominate in the next 5-10 years, but **new production capacity is not keeping up.**

- DNV, Statnett, NVE and IEA 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, O&G production and hydrogen production. How much is electrified will vary with power prices, available production capacity and grid 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.

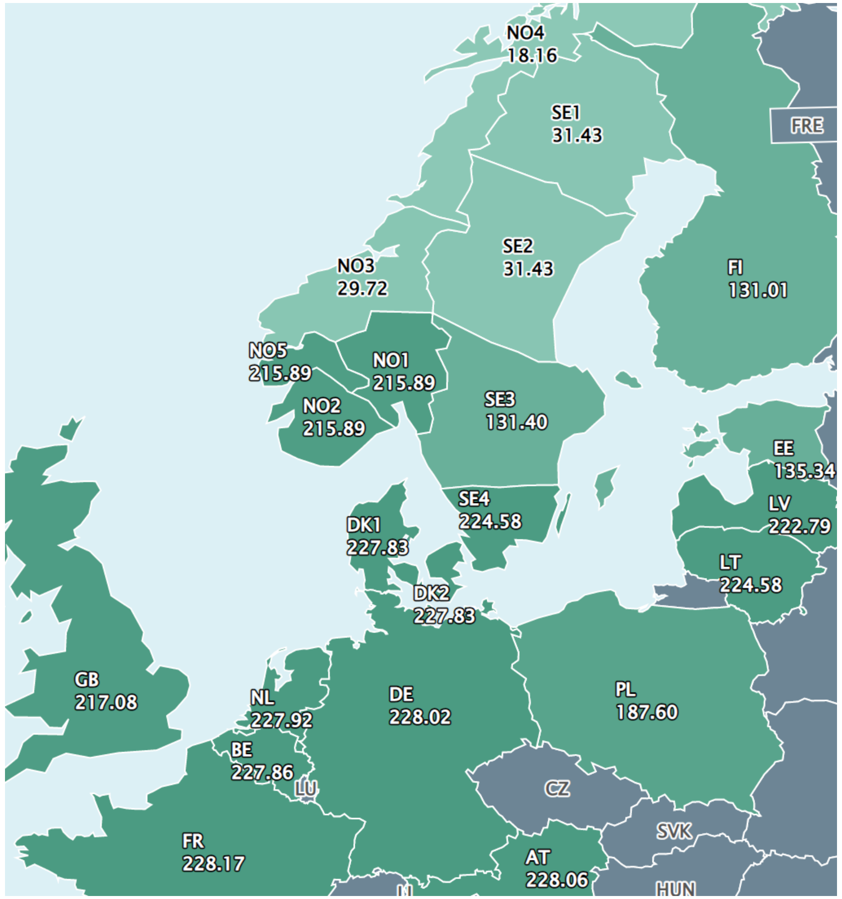
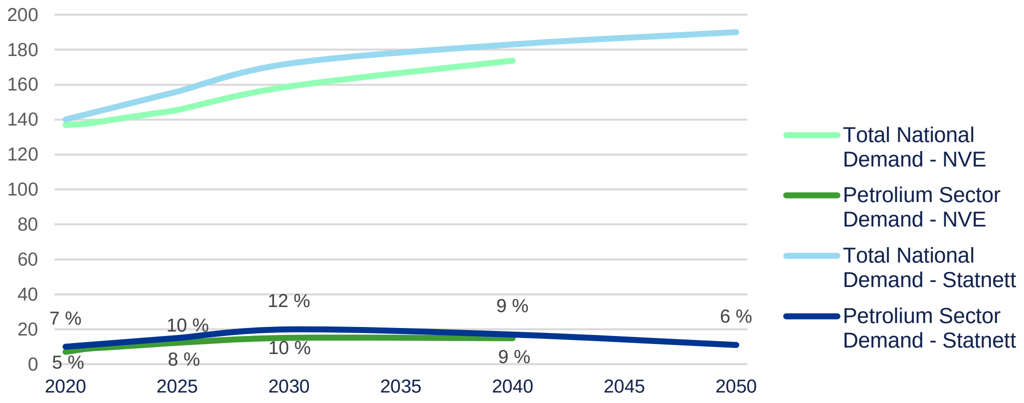


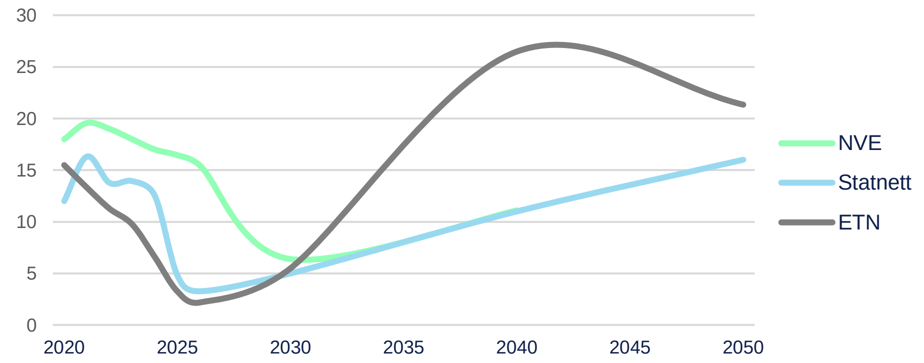
Illustration: Hourly power price (19-20, NOK) in Europe, 28th April 2022 (Nordpool)

Power demand will rapidly increase the coming year – new power capacity will not keep up

Forecasted national electricity demand (top) and surplus (bottom)

[TWh]





Source: DNV

NVE, Long-term power market analysis (2021 – 2040)

The analysis points 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 as the largest growth sectors, with an important increase in demand from the petroleum sector towards 2035, followed by a reduction. They also point to how electrification of the petroleum sector is resulting in significant grid investments. 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 from 2030 onwards. NVE predicts the power surplus to reduce from 20 TWh today to around 7 TWh in 2030.

Statnett, Long-term market analysis (2020 – 2050)

Statnett predicts little new power production before the end of this decade beyond what is currently being built. This leads to an expected power surplus of 4 TWh in 2030 (3 TWh in 2026), compared to 15 TWh today. On the demand side, a larger growth than earlier forecasts is expected due to strong trends and electrification plans for transport and industry. An uncertainty in the analysis is the extent of the electrification of the petroleum industry, and how fast it will decline with the decommissioning of the sector. In the basis scenario, the full electrification of the NCS potential is not used.

DNV, Energy Transition Norway (2021 - 2050)

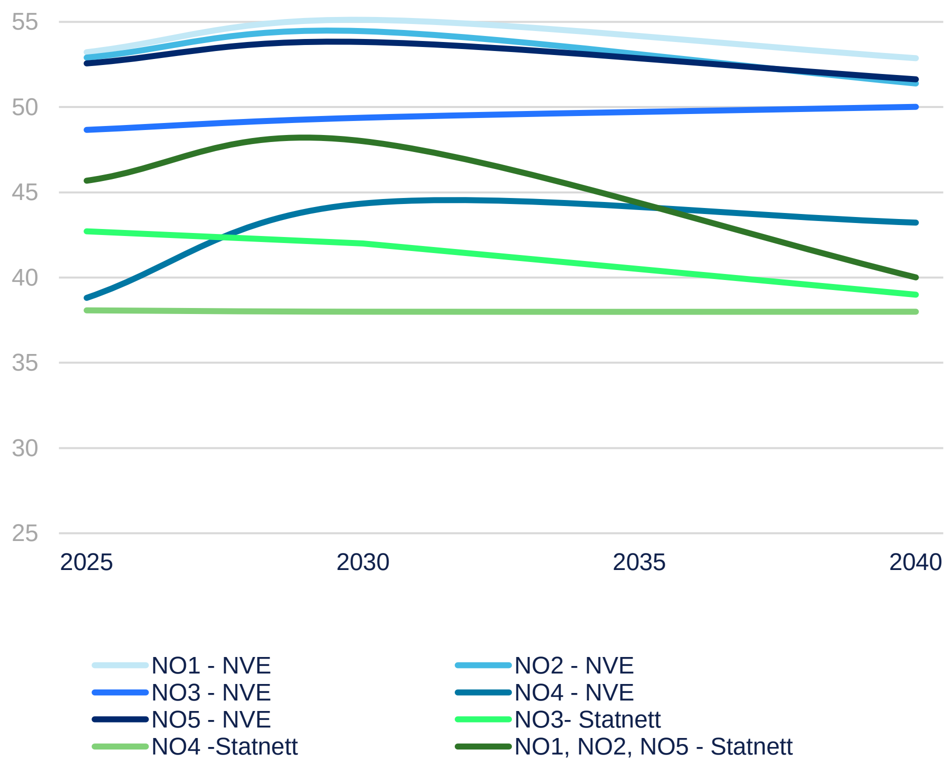
The report forecasts that traditional demand will consume the existing electricity surplus. This will lead to a deficit of domestic electricity supply for further decarbonisation plans and new industrial growth. On the production side, new hydropower capacity is limited, and onshore wind is facing increased public resistance. Offshore wind can increase power production the most going forward, although the lead time for these projects are long, and we see a growth inn power production from 2040. The report expects a 58 percent electrification of the NCS energy demand. To supply the NCS with electricity Norway must likely import electricity for several years between 2025-2035.

KonKraft, The Future Energy Industry on the NCS, Status update 2022

The KonKraft report refers to the demand and generation trends of the Statnett basis scenario of national demand of 170 TWh in 2030, of which 20 TWh are from the petroleum industry. In addition, the reports presents the potential for electrification on the NCS. If all the existing, planned and discussed project on the NCS are electrified, this represents a demand of 23 TWh in 2030, which will require extensive grid investments.

The domestic price differences are expected to continue

Forecasted power prices
[EUR/MWh]



NVE, Long-term power market analysis (2021 – 2040)

The 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. The power prices in Norway are expected to be high due to high prices on the continent and in Great Britain. Due to bottlenecks in transmission grid capacity between Northern and Southern Norway, the prices in Northern Norway are not as affected. This trend is expected to continue in the next decades.

Statnett, Long-term market analysis (2020 – 2050), update on prices in Dec. 2021

Power prices are rising as a result of increased carbon prices. European influence will increase power trade and price volatility. The average price is relatively similar to historical prices but will vary much more through the day and the year. Since the interconnector capacity is higher in Southern Norway, the prices increase relatively more in the south. Towards 2030, the direct effect of the carbon price on power prices is declining due to planned decommissioning of fossil-fueled power stations on the continent. NO1, NO2 and NO5 are modelled to belong to the same price area in the 2021 update.

DNV, Energy Transition Norway (2021-2050)

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 ETN 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.

Appendix C: Decarbonisation measures not assessed

Decarbonisation measures not assessed

Decarbonisation measure	Reasoning
Consolidation measures	According to KonKraft, consolidation measures can reduce GHG emission overall by 0.5 million tonnes CO2e/year in 2030 [1]. These are measures that encompass changes in the infrastructure to extract resources in a more efficient way, e.g. gathering several gas streams in fewer compressors to reduce compressor capacity, or removing a platform by re-routing the well current to a facility with reserve capacity. These are complex and comprehensive projects that require large investment decisions.
Small-scale, modular nuclear power reactors	Small-scale and modular nuclear power reactors on floating constructions can provide a stable power supply, and could be a potential solution to decarbonising assets that are difficult to electrify from shore. Concepts are currently under development with options of leasing, which could offset stranded asset risks. However, the high costs as well as public perceptions are major obstacles to implementing this on the NCS.
Other energy efficiency measures	Energy efficiency measures are important in reducing the energy consumption and as such the emissions from producing oil and gas. Although the total effect on emission reductions on the NCS can be substantial, the measures amount to smaller reductions individually than other large measures, such as electrification from shore. The measures are also well-known and easier to implement within a relatively short time horizon. It is assumed that operators will investigate such opportunities on an individual basis.
Reduced flaring	Measures to reduce flaring include, amongst others, optimization of operating procedures and implementation of systems for closed flaring with gas recovery. These measures can also relieve valuable natural gas, either for exports and increased revenue or used locally for power- and heat production [1]. However, GHG emissions from flaring accounts for around 6 percent of total emissions from the petroleum sector, thus has a limited emission savings potential in this context. It is assumed that operators will investigate such opportunities on an individual basis.

Image: Floating nuclear reactor Akademic Lomonosov, Image source: Bloomberg

[1] KonKraft, Status report (2022)

Appendix D: Detailed overview of non-prioritised technologies

Non-prioritised measures comparison (1/2)

High	Medium	Low

Decarbonisation measure 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 scope 3 synergies Medium: Limited scope 3 synergies Low: No scope 3 synergies	
Compact top-side CCS			Complex value chain, in particular for transport and storage.	High costs (shut down), low CO2 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 percent 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

Non-prioritised measures comparison (2/2)

High	Medium	Low

Decarbonisation measure 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 scope 3 synergies Medium: Limited scope 3 synergies Low: No 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
Energy efficiency – CO2-EOR				Availability of CO2, CCS infrastructure, not applied offshore on NCS	Limited opportunities (apart from CCS hubs)	Limited reduction potential	Limited possibility of storing CO_2 from e.g. blue hydrogen production.	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	

DNV

3.2 Decarbonisation measures
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 a reliable technology for power generation and mechanical (compression) or marine drives. On the NCS, the gas turbines typically have a rated power of 25MW (LM2500).
- Traditionally gas turbines use natural gas as the 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).
- 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.
- 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.

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 ongoing research)

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

- Technology qualification for re-use of existing infrastructure and increasing co-firing volume; Novel technology for more efficient gas turbines (or fuel cells); Subsea fuel cells for power production and subsea storage; 3D-printing of ammonia- and hydrogen-fired turbines.

3.2 Decarbonisation measures

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

- **Safety:** Both hydrogen and ammonia fired turbines and associated infrastructure need specific safety measures and technology qualification, especially for offshore applications.
- **Available infrastructure:** The infrastructure for production and transport of low-emission hydrogen and ammonia is limited and needs to be established.
- **Emissions:** New studies show that hydrogen may have higher global warming potential (GWP) than previously estimated – around 11 ± GWP100 [1]. As such it is important to ensure limited leakage. Combustion of ammonia can lead to increased NOx emissions, and as such measures are needed to be compliant for NOx regulations and permitting. Water injection is a remediation option. Demin water required.
- **Efficiency and volumes:** Compared to combustion of natural gas in gas turbines, the total energy efficiency of firing hydrogen or ammonia is roughly halved (when including loss of energy from production and treatment). Moreover, the volumetric calorific value of hydrogen is three times as low as that of natural gas.
- **Costs and policies:** Low-emission hydrogen and ammonia still has substantially higher cost for producing and transporting the fuel compared to natural gas. Stronger policies and support measures are needed to close the gap.
- Need for reliability and redundancy is to be considered. Combustion dynamics and flashback are key research items (for high percentage of co-firing and fluctuating load).
- For ammonia: Flame extinction and long flames need redesign for higher % co-firing.

Industry opportunities and synergies

- Establishing a market for hydrogen/ammonia can facilitate faster developments within production (both green and blue), infrastructure, safety requirements and frameworks, and enable a transition of Norwegian industry to low-carbon and renewable gases for own use or export to nearby markets.
- Replacing gas-fired turbines with fuel cells – this will increase the efficiency from around 35% to 40-60% or higher (70-80% for novel technologies).
- For (specific) new generation gas turbines, hydrogen capabilities (e.g., co-firing or 100%) may become the standard post-2030.
- Synergies may be found with nearby industries or offshore energy islands producing hydrogen in the future. 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.

[1] UK Department for Business, Energy and Industrial Strategy, Atmospheric implications of increased hydrogen use (2022)

3.2 Decarbonisation measures
Compact topside CCS

For capturing GHG emissions that are hard to abate through electrification measures, such as from FPSOs or direct-driven equipment, CO_2 capture and storage can be implemented directly at the installation. Compact topside CCS aims to use compact capture units to capture CO_2 directly from the turbine exhaust. Due to weight and volume constraints on the installations, lighter and smaller units are needed. Developments are progressing and the first commercial products for offshore applications are recently made available on the market, however not implemented. Availability of topside capacity and small CO_2 volumes is a concern.

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 but can be applied to all offshore installations [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

- Significant topside capacity is required, likely only being applicable for FPSOs for brownfield installations. With few FPSOs on the NCS, the application scope is limited.
- 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). For most installations, volumes will be too small to justify the cost of CCS infrastructure.

Scaling potential and timeline

Short term (2022-2030): CO_2 capture technologies are mature, however smaller and more compact units are still under development. A major bottleneck is the access to qualified CO_2 storage sites as it takes at least 5 years to develop a CO_2 storage site (depleted field) or longer for an aquifer. Before 2030 it is likely that only a few projects could succeed.

Long term (2030-2050): A more developed CCS infrastructure and lower cost could results in greater pick up. Potential after 2040 could be limited by the increasing public pressure on closing down fossil fuel operations and a decreased need in O&G as a result of the energy transition.

Illustrative concept of Just Catch Offshore on a FSPO

Illustrations: Aker Carbon Capture

[1] Just Catch™ Offshore – Aker Carbon Capture

3.2 Decarbonisation measures
Compact topside CCS

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 • Validation of direct injection of small amounts of CO_2 in injected water. • For direct injection, assessment of how exhaust gas reacts with rocks as well as potential impact on the injectivity rates should be further researched. • Explore models to connect to nearby platforms or gas-fired power hubs with CCS to increase volumes before CO_2 transport and storage. • Explore models to connect with existing CO_2 storage projects such as Northern Lights (NO) and/or others.

GHG reduction potential
Target emission sources O&G platforms, including floating ones and FPSOs, where power is supplied by gas turbines and where electrification measures are infeasible. In 2020, gas turbines offshore made up 68% of total upstream and midstream CO_2 emissions.
Technical reduction potential See "Gas-fired hubs with CCS, serving the NCS". Aker Carbon Capture's Just Catch Offshore has a capture rate of above 90% with a capture capacity of 120,000-360,000 tonnes CO_2/yr [1].
Realistic reduction potential Rystad Energy estimates compact topside CCS to target around 20% of the production volumes on the NCS towards 2050 and around 30% of emissions [2]. However, the potential for NCS is greatly dependent on the limitations of brownfield assets when it comes to space and weight and the need for rebuild. Also, availability of suitable storage sites and ensuring large enough volumes of CO_2 will significantly impact the potential.

Main challenges and opportunities
Development and implementation obstacles • Requires significant topside capacity (weight and space), likely only being applicable for FPSOs for brownfield installations. • There needs to be a suitable CO_2 storage near the installation. If none are available, transport via ship or pipeline to a suitable storage needs to be developed or connecting to existing infrastructure. However, this requires large volumes of CO_2. • Technical challenges related to storage sites. Each individual storage site needs to prove containment, sufficient capacity, economic rate of injection and monitorability. In addition, the storage activity could compete with other activities such as offshore wind farms, oil & gas activities etc. • Cost vs volume of CO_2 per installation: Compact topside CCS 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.
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. • There might be a potential for utilising the captured CO_2 for Enhanced Oil Recovery (EOR), although the volumes are likely far below the quantities needed.

[1] Just Catch™ Offshore – Aker Carbon Capture
[2] Rystad Energy, Technologies to improve NCS competitiveness (2019)

3.2 Decarbonisation measures
Energy efficiency through reservoir management: CO_2 EOR

CO_2 for EOR stands out as a technology that potentially can reduces CO_2-emissions notably 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 of the technology is to improve oil recovery, it is not long-term storage of CO_2. However, some CO_2 is stored in the process.

When CO_2 is re-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. The injected CO2 encounter trapped oil in the reservoir. The released oil expands and moves towards producing wells. The process requires large quantities of CO_2 that, in addition to CO_2 emitted during production, needs to be transported to the field from other emission points through pipelines or by ship.

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 safely 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 basin, where exploration cost may increase and production rates decrease.

Application scope and scaling potential

Application scope
CO_2-EOR technology is suitable for mature fields with potential for oil recovery by extending the lifetime and maximize production.

Scaling potential and timeline
Short term (2022-2030):
Scaling and deployment is linked to identify 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

3.2 Decarbonisation measures
Energy efficiency through reservoir management: CO_2 EOR

Maturity
Technology Readiness Level (TRL)

Short term (2022 – 2030):
- Mature technology from onshore operation where CO_2-EOR has been commercially deployed for decades.
- Offshore CO_2-EOR technology have only been deployed for the Petrobras operated Lulu field 2011, in Brazil.
- The technology for transportation of CO_2 by pipelines is available and in use. However only one CO_2 pipeline is in operation offshore (to the Snøhvit platform on the NCS)
- Technology for ship transport is also developed, however more unmature in larger scale.

Long term (2030 – 2050):
- Continued development of existing and new technologies
- Development of CO_2-EOR technology in connection with CCS hubs

Accelerating developments
- Cost-sharing of CO_2 pipeline networks
- Investments in smart and cost efficient topside solutions for processing CO_2-rich fluids
- Subsea technologies for separation and injection of CO_2 could reduce the need for large topside modifications

GHG reduction potential

Target emission sources
CO_2 for EOR stands out as a technology that potentially can reduces CO_2-emissions notably whilst, simultaneously increasing petroleum volumes, but it comes with a considerable cost and with a long lead time until improved recovery is realized (2-3 years) [2].

In addition to the emissions from the oil production process itself the source of CO2 injected to the reservoir could be from sources of emissions located elsewhere, e.g. industry.

Technical reduction potential
- CO_2 is trapped through residual, solubility and structural trapping over the life time of the project. 30 percent storage rate or higher have been documented [3].
- The technology is most promising on large fields where it is economically beneficial to do CO_2 -EOR.

Realistic reduction potential
- CO_2-EOR will contribute to reduced emissions from the oil and gas production process. However, it should be noted that increased oil production will eventually contribute to CO_2 emissions somewhere else in the value chain.
- It is acknowledged that pure CCS will store more CO_2 than CO_2 -EOR technology due to the additional production of HC that will create emissions elsewhere.

Main challenges and opportunities

Development and implementation obstacles
Cost:.
- High CAPEX and OPEX cost of conducting CO_2 -EOR offshore
- Significant investment cost in pipeline, topside and well cost are required
- Uncertainties related to cost of CO_2 from supplier including transportation cost

Technical:
- Lack of infrastructure to handle sufficient volumes of CO_2 for injection.
- Identifying suitable large scale reservoirs for CO_2-EOR
- Competition with other development options (e.g. gas injection)
- Lack of large amount of reliable supply of CO_2
- Lack of experience from offshore fields

Industry opportunities and synergies
- Several fields on NCS is mature and will be decommissioned over the next couple of years. CO_2 -EOR technology could improve the recovery of the remaining oil reserves and simultaneously reduce emissions [1]
- Develop CO_2-EOR in cooperation with CCS hubs

[1] Halland et al., CO2 for EOR combined with storage in the Norwegian North Sea, 2018
[2] Rystad Energy, Technologies to improve NCS competitiveness OG21, 2019
[3] Hosseininoosheri et al., Impact of Field Development Strategies on CO2 Trapping Mechanisms in a CO2–EOR Field: A Case Study in the Permian Basin (SACROC Unit), 2018

3.2 Decarbonisation measures

Energy efficiency through reservoir management: Artificial intelligence

Machine learning and digitalisation (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. It is difficult to measure the total contribution of AI on emission reduction as the processes are effective on several layers. AI will dominate technology development in foreseeable future.

Short description

Artificial intelligence is intelligence demonstrated by machines and includes:

- Machine learning – computers systems learning from and interpret data without human interaction
- Digitalisation – complying physical data in an easy way to be used digitally

In the oil and gas industry Machine learning can, for instance, 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. Additionally many attempts have been applied to seismic interpretation to speed up exploration prosect identification.

Digitisation in the industry gives faster access to useful data that can be used to improve technical workflows

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

Application scope and scaling potential

Application scope
Machine learning is most valuable in planning activities where multiple scenarios can be provided for better decision making.

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

By investments in AI:

- Equinor technology strategy 2019 predicted [1]:
    - Automated drilling – 15% cost reduction
    - Future fields – 30% capex reduction & 50% opex reduction
- DNV GL 2020 estimates [2]:
    - 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.

[1] Equinor, Creating energy from digital opportunities,
[2] DNV, OG21 – Study on Machine Learning in the Norwegian petroleum industry, 2020

3.2 Decarbonisation measures
Energy efficiency through reservoir management: Artificial intelligence

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

Short term (2022 – 2030):
Artificial Intelligence is currently being applied to assets in the North Sea
- All the major oil companies operating in the NCS have AI strategies implemented e.g. Equinor, Shell, Aker BP etc..
- The maturity of the different applications varies

Long term (2030 – 2050):
AI – will dominate technology development in the industry for the foreseeable future
- The technology will be applied more widely as computer programs become more sophisticated

Accelerating developments
- To enhance digital awareness and knowledge, E&P companies to partner with niche IT companies and training staff
- Build trust in Machine learning solutions
- Better quality assurance and quality control (QA/QC) of data used in the applications

GHG reduction potential

Target emission sources
AI contributes to more efficient delivery of processes and technical deliveries. Increased efficiency on all levels will reduce emissions directly and indirectly.

Largest impact is likely related to scope 1 emissions.

Technical reduction potential
[1] estimates an 15% reduction for a specific company in scope 1 and 2 emissions to potentially be obtained through improvements of operational and energy efficiency – this estimate is overall and not specifically related to reservoir management.

Realistic reduction potential
The total reduction in emissions related to AI is difficult to measure as more efficient processes will impact on several levels of the operation. More detailed data creates better understanding of areas of improvement and where to prioritize the effort.

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 Machine learning models and outputs
- Diligent management of data quality is needed for ML to succeed
- Machines cannot replace humans in all operations
- Impact is still uncertain

Industry opportunities and synergies
- Ongoing processes for E&P companies to establish smart partnerships with IT and digitisation specialists.
- Sharing lessons learned,
- successful ML algorithms,
- case studies for accelerated learning and ML adoption - this is more likely to happen for [2] :
  a) Environmental monitoring
  b) Energy efficiency
  c) Maintenance optimization / integrity management

[1] BCG: Lynos et. al., The AI Angle in Solving the Oil and Gas Emissions Challenge, 2021
[2] DNV, OG21 – Study on Machine Learning in the Norwegian petroleum industry, 2020

3.2 Decarbonisation measures
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.

Photo: Shutterstock/NTB

3.2 Decarbonisation measures
Optimized gas turbines: Waste heat recovery

Maturity Technology Readiness Level (TRL)	GHG reduction potential	Main challenges and opportunities
Short term (2022 – 2030): • **WHRU –** TRL 7 • **Combined cycle –** TRL 7 (installed on Oseberg, Snorre and Eldfisk) • **STIG –** TRL 5 (only onshore applications)	**Target emission sources** The source is a gas-fired turbine. As previously mentioned, gas turbines make up around 83% of total scope 1 emissions from O&G production..	**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.
Long term (2030 – 2050): • **WHRU** – TRL 7 • **Combined cycle** – TRL 7 • **STIG –** TRL 5 / 6	**Technical reduction potential** • **WHRU** – The reduction potential will depend on the heat demand of the installation but estimations show emissions could be reduced up to 20%. • **Combined cycle** – Combined cycle turbines can replace traditional gas turbines used for power generation. The electrical efficiency will go from around 38% to 51%, which would reduce the CO_2 emissions by around 25%. However, the number could be lower depending on the heat demand. • **STIG** - The electrical efficiency will go from around 35% to 39%, which would reduce the CO_2 emissions by around 10%. However, the number could be lower depending on the heat demand.	**Industry opportunities and synergies** • WHRU, combined cycle and STIG are already established technologies with limited opportunities for industrial development in Norway.
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.	**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.	

3.2 Decarbonisation measures
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: (i) Battery as stand by, (ii) eliminates load transients, (iii) 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.

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.

Efficiency of gas turbines are highly dependent on load

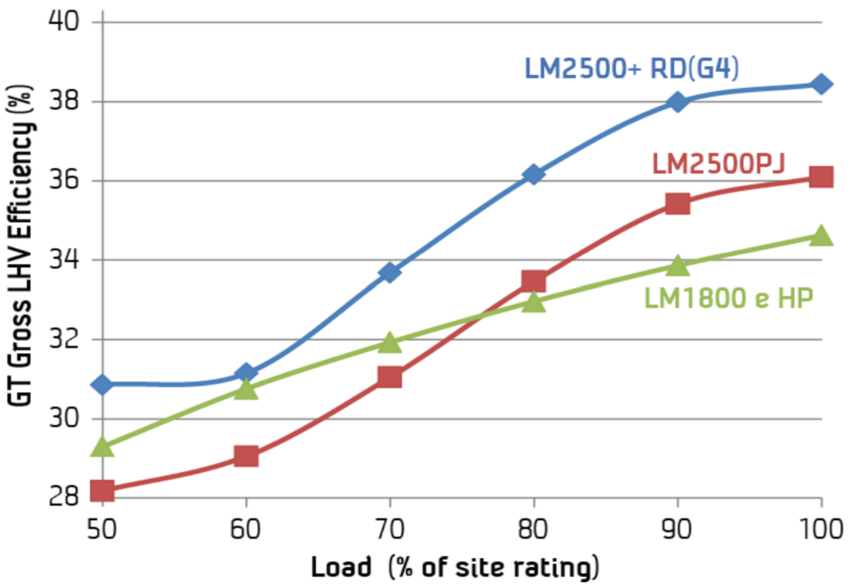


Illustration: Marit Mazzetti, OTC-24034-MS

3.2 Decarbonisation measures
Optimized gas turbines: Utilization

Maturity
Technology Readiness Level (TRL)

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

GHG reduction potential

Target emission sources
The source is a gas-fired turbine. As previously mentioned, gas turbines make up around 83% of total scope 1 emissions from O&G production.

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 –** Targets gas turbines for power production (around 50% of gas-turbine related emissions on the NCS). 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
- **Multiple units –** More turbines 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.
- Use of batteries on NCS could also help scale up the offshore wind industry by providing back-up power solutions during hours of low wind speed.

[1] Marit Mazzetti, OTC-24034-MS

3.2 Decarbonisation measures
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. There might be a potential for offshore geothermal power plants on the NCS, especially if re-using 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 full 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 (see figure):
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
Short term (2022-2030): Onshore geothermal plants have an expected timeline from idea to operations of 3-5 years (optimistic). Offshore systems will likely be more complex. No offshore geothermal plants installed as of yet. Expected developments:
- 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 decarbonisation 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.

Illustration of geothermal electricity production concepts

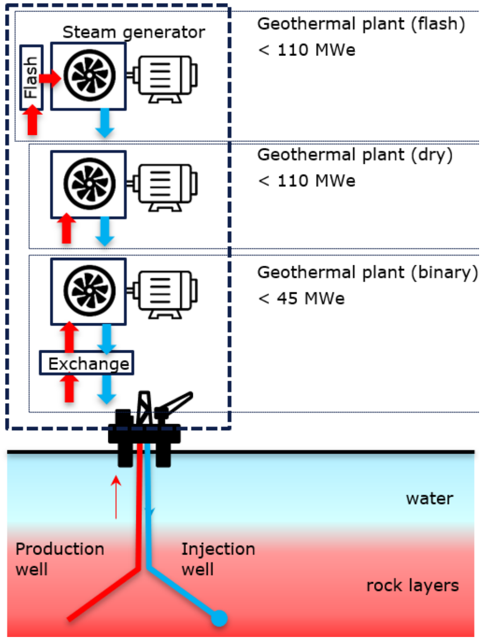


Illustration: DNV

3.2 Decarbonisation measures

Geothermal energy to reduce electrical power demand offshore

GHG reduction potential

Target emission sources
Replacing gas turbines at platforms for power production and heat demand by geothermal power plants. Although geothermal plants use some electricity for operation (e.g. ESP-pumps, cooling tower), this can be self-supplied.

Technical reduction potential
By replacing gas turbines with geothermal electricity and heat, the theoretical GHG emission reduction potential can be up to 100%. The potential per geothermal power plant is typically:

- Geothermal binary technology provides 2-3 MWe [2]
- Geothermal a flash or dry steam technology provides 17 tot 23 MWe [2].

Note: The potential 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 typical power plant sizes. In case of "increasing operational platform efficiency' gas turbines on the platform can be replaced by geothermal electricity. For this a reference case of 75 MWe per platform could be used (3x25 MWe gas turbine per platform [1])

Realistic reduction potential
The realistic reduction potential is case specific and has not been studied in detail for this report. The main requirements for deployment of offshore geothermal energy are:

- 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

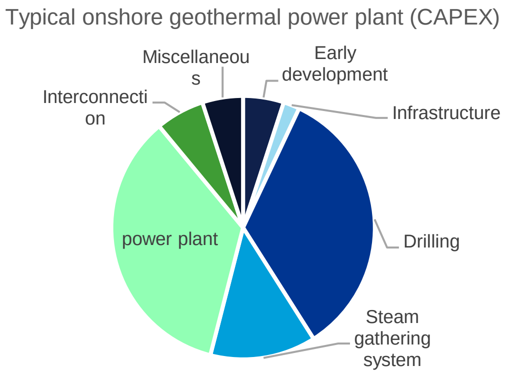
Development and implementation obstacles

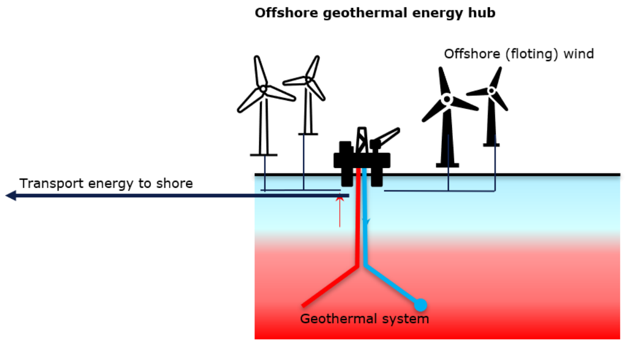
- Availability of thermal aquifer systems nearby the offshore platform with good conditions for geothermal energy (high temperature, high mass flowrates). Analysis show ~10% of reservoirs on the NCS are above 120 degrees, and even less above 180 degrees, although there are some hot-spots. Further assessment of geothermal potential is needed.
- Possibility to repurpose O&G wells might be limited (e.g. casings, insulation, well heads, tubing)
- Harsh offshore environment.
- Return on investment of geothermal plant compared to platform lifecycle (remaining lifetime of platform should be at least 20 years or more in order to justify investment, or find ways to re-use the power plant for other purposes).
- Subsea electricity cables needed in case of transport to shore.
- Permits and licensing (exploration + exploitation, environmental, grid access).
- Installation of technical room(s) at platform.
- High drilling cost compared to onshore geothermal plants (see CAPEX distribution figure)

Industry opportunities and synergies

- Extend lifetime of wells and installations by utilising platforms after O&G production has ended and repurpose oil/gas wells for geothermal heat/electricity.
- Create a offshore geothermal power hub, e.g. for hydrogen production, deep-sea mining, grid connection to shore, floating wind turbines connected to the hub, local offshore geothermal electricity.

Typical distribution of onshore geothermal power plant CAPEX (top) and potential offshore geothermal energy hub (bottom)





Source: DNV

[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

www.dnv.com

DNV