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The competitive edge of Norway's hydrogen by 2030: Socio-environmental considerations[☆]

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A R T I C L E I N F O

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A B S T R A C T

Can Norway be an important hydrogen exporter to the European Union (EU) by 2030? We explore three scenarios in which Norway's hydrogen export market may develop: A Business-as-usual, B Moderate Onshore, C Accelerated Offshore. Applying a sector-coupled energy system model, we examine the techno-economic viability, spatial and socio-economic considerations for blue and green hydrogen export in the form of ammonia by ship. Our results estimate the costs of low-carbon hydrogen to be 3.5–7.3€/kg hydrogen. While Norway may be cost-competitive in blue hydrogen exports to the EU, its sustainability is limited by the reliance on natural gas and the nascent infrastructure for carbon transport and storage. For green hydrogen exports, Norway may leverage its strong relations with the EU, but is less cost-competitive than countries like Chile and Morocco, which benefit from cheaper solar power. For all scenarios, significant land use is needed to generate enough renewable energy. Developing a green hydrogen-based export market requires policy support and strategic investments in technology, infrastructure and stakeholder engagement, ensuring a more equitable distribution of renewable installations across Norway and national security in the north. Using carbon capture and storage technologies and offshore wind to decarbonise the offshore platforms is a win-win solution that would leave more electricity for developing new industries and demonstrate the economic viability of these technologies. Finally, for Norway to become a key hydrogen exporter to the EU will require a balanced approach that emphasises public acceptance and careful land use management to avoid costly consequences.

Abbreviations

CCS	Carbon Capture and Storage
DENA	German Energy Agency
EU	European Union
H_2	Hydrogen
HHV	Higher Heating Value
LCOE	Levelised costs of electricity
LCOH	Levelised costs of hydrogen
LHV	Lower Heating Value
Mt	Million tonnes
NVE	Norwegian Water Resources and Energy Directorate (Norges vassdrags- og energidirektorat)
PEM	Proton-Exchange Membrane
PyPSA-Eur	Python for Power System Analysis — European energy system
SMR	Steam Methane Reforming

1. Introduction

The European Union has the ambition to be climate-neutral by 2050 [1]. As an intermediate goal to bolster its energy security and reduce its dependence on Russian natural gas (hereinafter gas) imports, the EU plans to replace parts of its gas consumption with 20 million tons (Mt) of green hydrogen by 2030, of which half will be produced domestically and half will be imported [2]. As the EU transitions away from fossil fuel imports, countries that depend on petroleum exports to the former will need to find a new market to tap into. One such country is Norway, whose petroleum exports represent 73% of the total country's exports value in 2022. Of this volume, 67% was exported to the EU [3]. In terms

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of availability of natural resources, political stability and regulatory status, economic resources, industrial know-how and adaptability, Norway is ranked as one of the top ten potentially most competitive hydrogen exporters in the world [4]. Should Norway succeed in realising this potential, it would be able to maintain its economic growth despite a transition away from fossil fuel exports [5]. However, this would require abundant renewable electricity to ensure minimal greenhouse gas emissions and price-competitiveness [5,6]. Yet, the power surplus of around 13 TW h (TWh) that Norway has been enjoying averagely in the last decade [7] could turn into a deficit by 2030 if the increased electricity demand resulting from the electrification of sectors is not followed by a proportionate expansion of the domestic renewable electricity capacity [8]. As pointed out by Cheng [6], timing is important in taking advantage of the window of opportunity for an energy transition. The point of departure of this work is that Norway should aim to become an important EU hydrogen supplier by 2030 and the main objective of this work is to evaluate this potential. This is measured by the cost-competitiveness against other non-EU hydrogen exporters, the environmental impacts on land use and the associated social implications.

Several techno-economic studies on the potential for low-carbon hydrogen export to the EU focused solely on the production costs. However, this could be misleading as the transportation costs could affect the overall cost-competitiveness of the exports, as highlighted by Refs. [9–11]. The transportation costs may vary due to the travelling distance and the form in which the hydrogen is being transported. In contrast, a value chain approach that includes the costs implicated in the transportation of hydrogen export would provide a better overview of the cost-attractiveness of hydrogen as an export commodity [11]. This approach has been adopted by Galimova et al., Roos, Seiti et al., Okunlola et al., Wietschel and Hasenauer for the export of blue and green hydrogen from non-EU countries in North and South America, Africa, Northern Europe to Europe, including Germany [11–14]. Additionally, three studies concern the export of blue or green hydrogen from Norway to Germany. Andressen et al. [15] evaluated the feasibility of exporting green liquid hydrogen from Norway (Glomfjørd) to German cities (Berlin, Munich, Magdeburg) via the ports of Hamburg, Bremerhaven or Rostock. Stiller et al. [16] compared the costs of exporting blue and green hydrogen from Southern and Northern Norway to Northern Germany (Hamburg) via eight different pathways, of which two considered production in Southern Norway before being transported through hydrogen pipelines, and two considered production in Northern Norway before being exported by liquid hydrogen ships. Ishimimoto et al. [17] compared the techno-economic cost of large-scale production and transport of blue liquid hydrogen and liquid ammonia from Northern Norway (Hammerfest) to Rotterdam and Tokyo.

The techno-economic assessments mentioned above were quantified based on static values on the electricity prices and capacity factors that are applied to renewable electricity technologies. While this provides a high-level view of the economic potential of hydrogen exports to the EU, the reality is that electricity prices and renewable energy generation can vary significantly from site to site [18]. To capture this reality, the energy system optimisation model, PyPSA-Eur, is used to derive the costs of hydrogen exports from Stavanger (Southern Norway), Trondheim (Central Norway) and Tromsø (Northern Norway), each representing different geographical points and electricity price zones in Norway. Further, it is critical to consider the volume of hydrogen exports targets, which impacts the amount of renewable energy required, and thereby demands the use of more natural resources like land. In Norway, the future renewable energy expansion is likely to rely on either onshore or offshore wind [8]. By allowing the expansion of renewable energy capacity in the model, it is possible to calculate the amount of land or sea area needed for the production of hydrogen. For hydrogen exports to be a viable alternative for Norway's post-petroleum future, we assume that Norway should aim to secure the same market share as its gas exports as its hydrogen exports, that is 20% market share of the EU's hydrogen import demand in 2030. This equates to an export of 2 Mt hydrogen, and aligns well with the assumption taken by Espegren et al. [5] on the role of hydrogen exports in Norway to transition away from petroleum exports.

Given the joint-declaration by Norway and Germany to cooperate closely on developing a hydrogen value chain [19], this article focuses on the export route between the two countries. While the recent hydrogen value chain feasibility studies by DENA and Gassco on the construction of a hydrogen pipeline between Norway and Germany concluded that "no technical showstoppers have been identified", there remain substantial barriers concerning costs, regulatory framework, environmental impacts and financing model [20, p. 24]. Considering the timeline to 2030, we opt to evaluate the export of hydrogen in the form of ammonia, which can be safely transported on existing chemical and semi-refrigerated liquefied petroleum gas tankers and can leverage an established intercontinental transmission and distribution network [21]. Furthermore, it is considered the most cost-attractive carrier for shipping hydrogen [22]. The receiving terminal is assumed to be the port of Wilhelmshaven, where a new hydrogen pipeline could potentially be built in the vicinity and facilitate further distribution inland [20].

The novelty of this article builds on several pillars. (i) This article is the first study in Norway which models both blue and green hydrogen in a technology-open manner to study system-wide impacts of cost-optimal export pathways. (ii) The model allows for an analysis of the distribution of renewable energy and hydrogen from different regions of Norway and the discussion on the energy needs, land-use and associated social consequences at a regional level. (iii) Further, our results build on a broad cost-sensitivity analysis addressing the fundamental uncertainty in future costs of technologies including carbon capture and storage, electrolysis and offshore wind turbines.

The key research question for this article is "What is the potential for Norway to be an important hydrogen supplier to the EU?". Guiding the analysis are the following sub-questions:

1) How fast does Norway need to ramp up the expansion of its renewable energy capacity to meet the EU's hydrogen import needs?
2) What are the economic and environmental trade-offs between blue and green hydrogen production in Norway, considering current infrastructure and future energy policy needs?
3) What are the socio-economic impacts of expanding onshore and offshore wind capacity in different regions of Norway, and how can policy address potential disparities?

These research questions are investigated through the lens of three different scenarios involving blue and green hydrogen as described in the Methods section. There, we dive into specifics of the foreseen hydrogen pathways, and then discuss how we adapted the PyPSA-Eur model for this article. In particular, we extend PyPSA-Eur with additional components and linear constraints forcing hydrogen exports; a relatively novel concept in the context of capacity expansion model. We further give an overview of relevant cost assumptions and present social and environmental concerns of hydrogen export pathways. The Results section then discusses the accruing costs in the different scenarios, defines the needed willingness-to-pay to evade social acceptance issues, and marks down the land use needs and power system changes in Norway following the different hydrogen export pathways and variations in costs. This paper is rounded up by a Discussion and Conclusion.

2. Methods

2.1. Hydrogen pathways

This article examines the potential for hydrogen exports based on three scenarios from Norway to Germany: "A Business-as-usual", "B Moderate Onshore", "C Accelerated Offshore". We use an integrated energy system optimisation model to investigate a range of outcomes

Table 1
Description of scenarios and their implementation in the energy system model.

Scenario	Model implementation	Description
A: Business-as-usual	No restriction to baseline model.	Aligns with current policies where only blue hydrogen is produced for export.
B: Moderate onshore	Steam methane reforming (SMR) not allowed.	Green hydrogen export using the cost-effective renewable electricity source.
C: Accelerated offshore	SMR not allowed, total yearly offshore wind power production must be at least the total yearly electrolysis demand in Norway.	Green hydrogen export using offshore wind power.

(including hydrogen cost, land use and subsidy levels) in three different scenarios, see Table 1. At the basis of all scenarios lies the fixed target for Norway to supply 2 Mt of hydrogen (derivatives) annually to continental Europe. The scenarios and modelling assumptions are tailored to a 2030 planning horizon.

Where the scenarios differ is in the methods and energy sources for hydrogen production. See Table 1 for a brief summary. Scenario A (*Business-as-usual*) explores the export of both blue and green hydrogen while allowing the expansion of the lowest-cost renewable energy. That is, hydrogen may be produced through the conventional method, steam methane reforming (SMR), combined with Carbon Capture and Storage (CCS) technology at 90% capture rate, as well as through water electrolysis via Proton-Exchange Membrane (PEM) electrolysers that are powered by renewable energy. In practice, this leads the model to invest in SMR with CCS in most cases since this is significantly cheaper than electrolysis at baseline 2030 technology cost assumptions. In Scenario B (*Moderate onshore*), only green hydrogen production is allowed based on the potential for expansion of renewable energy generation in Norway. This leads the model to invest in a significant variable renewable portfolio in Norway in order to supply the electrolysis; renewable investment is dominated by onshore wind in this case. Given the low social acceptance towards onshore wind installations in Norway [23], Scenario C (*Accelerated offshore*) assumes the same but the production of green hydrogen relies on an accelerated roll-out of offshore wind turbines in Norway. In this scenario, we add the constraint that offshore wind power (as opposed to onshore wind and solar) must supply all the electricity for electrolysis; this is however only accounted for on a net yearly basis. For all scenarios, we assume high prioritisation of energy security in Norway in that it may not become an electricity importer on a net yearly basis. Fig. 1 illustrates the value chain of ammonia exports considered in the scenarios, from the energy sources in Norway to the transport of ammonia to the receiving terminal in Germany.

As mentioned above, this article considers marine shipping of ammonia from Norway to continental Europe. We model power requirements and losses in the production of ammonia, but do not consider ammonia cracking to convert the exports back to hydrogen; rather, we model the exports of an amount of ammonia having the energy content (measured in lower heating value) of 2 Mt of hydrogen, being 66.7 TWh. We disregard ammonia cracking due to the large uncertainty in final end-use of imported green hydrogen. A recent projection of green hydrogen demand by 2030 in Germany [24] notes that there is already a 1 Mt hydrogen demand (currently grey) in the chemical industry for the production of ammonia; demand from the transportation and shipping sectors may also be in the form of ammonia or other synthetic fuels. Including conversion losses in ammonia cracking would overestimate costs if the resulting green hydrogen is to be converted back to a liquid fuel. Given the nascent stage of the use of ammonia as a fuel in ships, we assume that the transport of ammonia will be by container ships running on conventional fuel in 2030.[1] Hydrogen pipelines are excluded in the scenarios due to potential delays in funding and approval processes for the constructions, (despite being considered as technically possible by 2030 [25]).

In the model, the export pathways are modelled as three separate corridors characterised by having a capital investment cost (representing the cost of an ammonia production plant), efficiency losses (representing imperfect conversion from hydrogen to ammonia), a running power requirement (representing the electricity required to run the ammonia production plant) and a marginal export cost (representing the cost of shipping ammonia; dependant on the shipping distance). While we have based these parameters on ammonia as an energy carrier (see Table 2 for the parameters used in the present study), the model formulation itself would be equivalent to an alternative carrier such as liquid hydrogen. As discussed below, the modelling results are not particularly sensitive to shipping costs.

2.2. Choice of modelling framework

In order to generate plausible system solutions in each of our three scenarios, we employ an energy system optimisation model covering the electricity, transportation, heating and industrial sectors. The specific tool we use is PyPSA-Eur, an open-source sector-coupled model for the European energy system [26,27]. At the core, this is a capacity expansion model; a type of optimisation model where both investment and operation decisions are subject to optimisation. The model is equipped with an objective function representing total system cost (as a sum of annualised investment costs and yearly operating costs). Investment variables subject to optimisation include onshore and offshore wind capacities, solar capacities, conventional natural gas and nuclear power generation, energy storage capacities (batteries, hydrogen storage, hot water storage), transmission expansion, heating infrastructure (combined heat and power plants, gas boilers, heat pumps, resistance heaters) and power-to-X capacities including electrolysis, ammonia and methanol synthesis and fischer-tropsch liquid fuel production. The model also includes existing capacities of the above technologies with lifetimes beyond 2030. Existing hydro, coal and oil power plants are similarly included, but with fixed capacities that cannot be expanded. For a complete overview of the technologies included and optimised in the model, see the official PyPSA-Eur documentation.[2]

In a typical capacity expansion model such as PyPSA-Eur, the adequacy of feasible model solutions is ensured by including in the model formulation a simulation of system operations over one full year at subdaily time resolution. Demand for electricity and other energy carriers is fixed in advance for each node and time step in the model; dispatch and optimal power flow problems for each time step are included in the overall problem formulation. Thus, both operational and investment decision variables are subject to optimisation jointly. PyPSA-Eur (as well as many other capacity expansion models) is formulated as a linear program, meaning that both constraints and the objective function are linear in the decision variables. This entails simplifications of non-linear real-world effects but makes the optimisation model tractable to solve at high spatial and temporal resolution.

[1] Note that shipping costs (see Fig. 4) only play a minor role in final exported hydrogen costs, meaning that shipping fuel choice is unlikely to have a large effect on our results.

[2] https://pypsa-eur.readthedocs.io/en/latest/introduction.html.

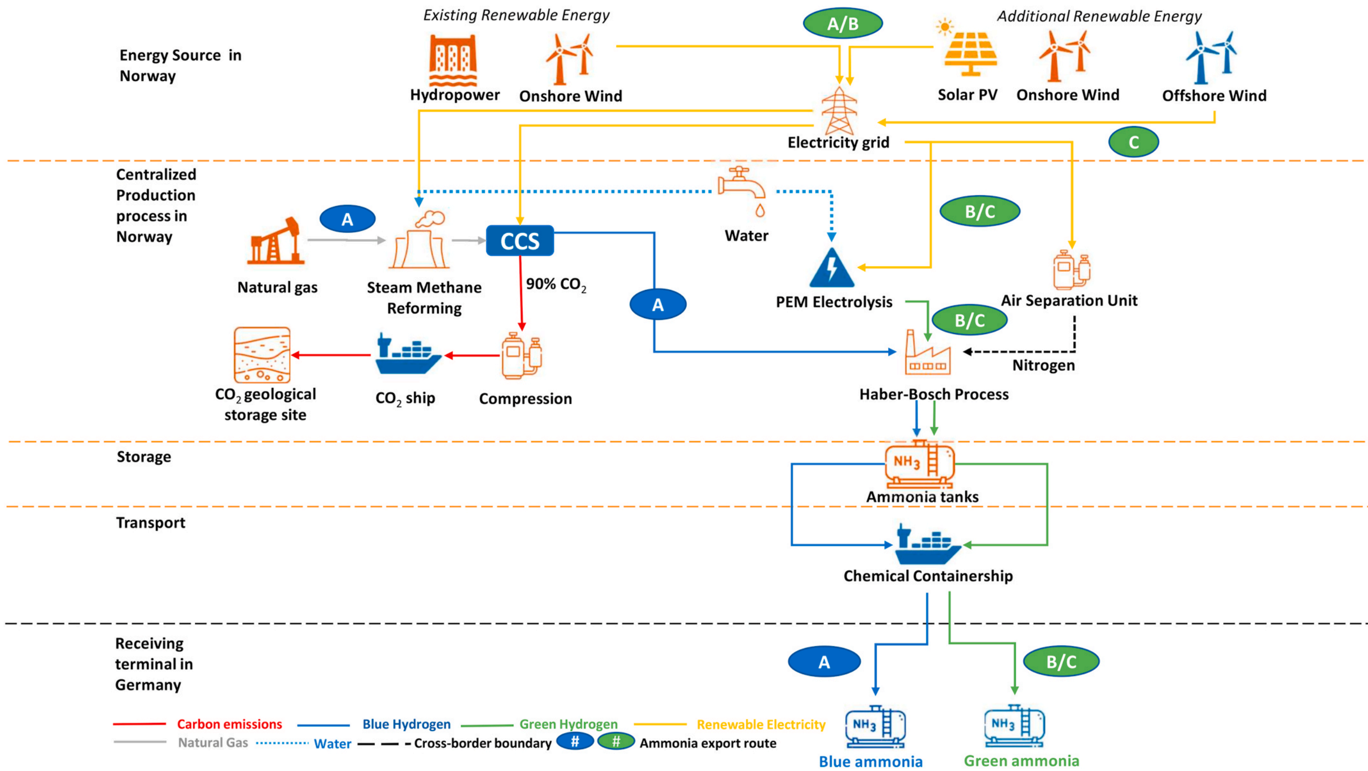

Fig. 1. Simplified ammonia export value chain from Norway to Germany in 2030[1]
[1]Clipart source: flaticon.com.

2.3. Modelling setup

We restrict PyPSA-Eur to the countries around Norway and the North Sea, namely Norway, Sweden, Denmark, Finland, the UK, the Netherlands and Germany. We choose a 20-node spatial resolution at the transmission and demand level, but allocate only one node per synchronous zone and country for Denmark, the UK, the Netherlands and Germany, while modelling Sweden with 2 nodes and Norway with the remaining 11 nodes (see Fig. 2). This ensures adequate representation of transmission bottlenecks in and around Norway. In order to better capture variations in renewable energy availability, we model renewable generation at a spatial resolution of 60 different regions; each region being connected to the closest of the 20 transmission nodes. We obtain the desired network resolution using the built-in hierarchical clustering function of PyPSA-Eur [28] based on onshore wind capacity factor profiles — starting from small initial regions, nearby nodes with similar onshore wind capacity factors are successively merged. Furthermore, the temporal resolution of the model is reduced using the segmentation approach introduced in Ref. [29] to a total of 1000 time steps. The model is run over the single weather year of 2013 [30] — this weather year is close to average in terms of total system costs compared to the 1980–2020 period and is the default in PyPSA-Eur, making the results easier to compare to other studies. Total yearly CO_2 emissions over the entire modelling region are subject to a 55% reduction compared to 1990 levels in accordance with the EU and Norway's climate target for 2030. This reduction is implemented as a constraint on total model-wide CO_2 emissions; the model then finds the most cost-effective solution to meet this constraint while satisfying the given energy demand. Following the PyPSA-Eur default [31], renewable expansion is restricted to a selection of CORINE land use types [32].

We add a number of new components and linear constraints to PyPSA-Eur in order to model our hydrogen export scenarios. These are as follows:

1. A new network bus with attached store/stockpile representing continental hydrogen demand, and three links from the Norwegian export hubs to this bus, as described above.
2. A constraint forcing the hydrogen demand stockpile to be filled with the equivalent of 2 Mt of hydrogen (amounting to 66.7 TWh of ammonia in our case) by the end of the year.
3. A constraint forcing Norway to remain a net electricity exporter on a yearly basis. Specifically, the total net electricity exports (i.e. the difference between total yearly exports and imports) is constrained to be greater than 0. This constraint maintains the current status quo of Norway's role as an electricity exporter, but also crucially prevents the import of electricity only for this to be used in electrolysis and exported again as green hydrogen.
4. In Scenario C, a constraint is added forcing total yearly Norwegian offshore wind production to match total yearly electrolysis electricity consumption.

Thus, our scenarios are based on using an optimisation model to explore cost-optimal solutions for exporting hydrogen from Norway, without making assumptions about exactly where and when this hydrogen is produced, or with which power (except for Scenario C, forcing the use of offshore wind).

2.4. Technology costs and sensitivity analysis

Table 2 shows the complete overview of the baseline cost assumptions in our model. All costs are given in 2023 euros, and technology costs and efficiencies are given for 2030, wherever possible. When necessary, we convert between NOK and EUR based on an average 2023 exchange rate of 1 EUR = 11.302 NOK [33]. It is noteworthy that e.g. PEM electrolysis efficiency is forecasted to increase by at least 5%-points in the decades beyond 2030 [34] (subject to uncertainty), which would decrease the Levelised Cost of Hydrogen (LCOH) for model runs set in later years than 2030. In the model, capital investment costs are

Table 2
Overview of baseline cost assumptions for hydrogen production and transportation chain. All costs are given in 2023 euros; older cost data are converted using the Eurostat Harmonised Index of Consumer Prices.

Technology	Baseline assumption	Range	Source
Onshore wind investment	€1413/kW	±20%	[35]
Bottom-fixed offshore wind investment (excluding connection)	€2921/kW	±20%	[35]
Floating offshore wind investment (excluding connection)	€5269/kW	±20%	[35]
Steam-methane reformation with 90% carbon capture rate	€728/kW_{CH_4}	±20%	[36]
Steam-methane reformation conversion efficiency[a]	69%	fixed	[37]
Natural gas	€30/MWh_{th}	±20%	[38]
CO_2 sequestration[b]	€36.50/tCO_2	±20%	[39]
PEM electrolysis	€429/kW_e	±20%	[40]
PEM electrolysis efficiency[c]	65%	61%–69%	[34]
Ammonia synthesis[d]	€1570/kW_{th}	±20%	[36]
Ammonia synthesis hydrogen consumption[e]	1.15 MWh_{H_2}/MWh_{NH_3}	fixed	[41]
Ammonia synthesis electricity consumption[f]	0.25 MWh_{el}/MWh_{NH_3}	fixed	[41]
Ammonia shipping	€1.47/MWh_{th}/1000 km	±20%	[42]

[a] Efficiency is given in terms of LHV, and is lower than the reference value of 76% for non-CC SMR from the same source due to the additional energy requirement for the carbon capture process.
[b] Sequestration cost includes the levelised cost of both transportation of CO_2 and injection into depleted gas fields, but not the cost of capturing CO_2 (which is included in the capital cost of SMR plants with carbon capture).
[c] Efficiency is given in terms of LHV; this value corresponds to an efficiency of 77% in terms of high heating value (HHV). The range of efficiencies tested corresponds to 72%–82% in terms of HHV.
[d] Capital cost includes the air-separation unit needed for N_2 feedstock. The cost is per kW of hydrogen input capacity.
[e] Using lower heating values and assuming 178 kg H_2 input per 1000 kg NH_3 output.
[f] Using the lower heating value for ammonia, not including the electricity needed for the air-separation unit.

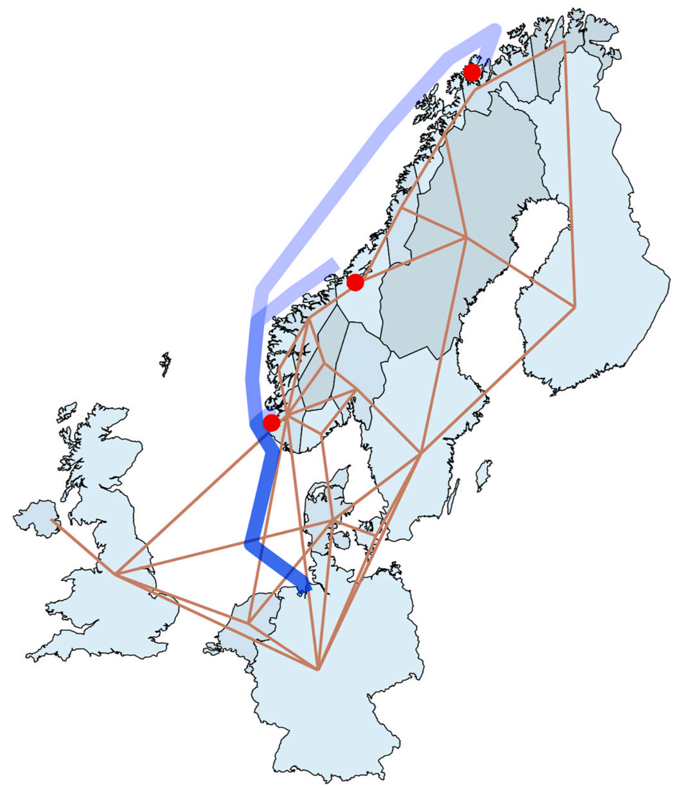

Fig. 2. The spatial layout of the model used in this study. The distinct model regions are shown, with the connecting lines indicating transmission grid connections. The thick blue lines illustrate the export corridors from Tromsø, Trondheim and Stavanger, marked with red dots. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

annualised with a 7% discount rate. Since all costs under consideration are subject to considerable uncertainty, we perform an extensive global sensitivity analysis in order to determine both which costs are most important for final hydrogen prices as well as to determine likely ranges of prices and system configurations across many cost combinations. In particular, our global sensitivity analysis consists of taking intervals of ± 20% around each baseline cost (listed in Table 2), and randomly sampling 500 points in the resulting parameter space. Then, we run the model for each of these 500 combinations of cost assumptions and each scenario. The resulting 1500 model solutions are used throughout the results section.

3. Results

The key results are summarised in Table 3; in the following sections we go into more detail.

3.1. Competitiveness of Norwegian hydrogen

Fig. 3 shows the distributions of Norwegian Levelised Cost of Hydrogen (LCOH) observed for each scenario across the 500 model optimisations, following the sensitivity analysis as described above. Under Scenario A (*business-as-usual*), only blue ammonia is being exported from Norway to Germany due to the cheaper cost associated with the production method, SMR and CCS, entailing the capture and storage of about 23 Mt of CO_2 annually.[3] Consequently, the cost of producing hydrogen and exporting it in the form of ammonia is the cheapest among the three scenarios, with a median cost (between 5th–95th percentiles) of €3.87 (3.50–4.27)/kgH_2 in 2030. Limiting the production to only green hydrogen, the cost of hydrogen export becomes around 34% higher in Scenario B (*moderate onshore*) at €5.18 (4.61–5.72)/kgH_2 and 65% higher in Scenario C (*accelerated offshore*) at €6.39 (5.54–7.25)/kgH_2. The cost uncertainty is found to be greater for green hydrogen, especially in Scenario C, which is completely reliant on offshore wind power. These costs include both production, ammonia synthesis (with resulting efficiency losses) and transportation. Note that we report costs in €/kgH_2-equivalent in terms of lower heating value energy content even though exports are modelled as using ammonia. Without ammonia synthesis and transportation, we find hydrogen production costs of €2.34 (2.05–2.63), €3.43 (2.95–3.83) and €4.51 (3.78–5.17) for Scenarios A, B & C respectively.

Fig. 4 shows the sensitivities of the final Norwegian LCOH to the various parameters subject to variation in the global sensitivity analysis. It should be highlighted that the first parameter relates to the efficiency rate of electrolysers, while the rest of the parameters relate to the different cost components in the supply chain. Although the electrolyser efficiencies have the same baseline value of 65% in both Scenarios B (*moderate onshore*) and C (*accelerated offshore*), the effects on the cost of hydrogen are higher in the latter due to the higher cost of electricity. A

[3] See Section 4.1 for a more detailed discussion of CO_2 capture and storage in Scenario A.

Table 3
Summary of key results. All ranges indicate the 5th and 95th percentiles over the sensitivity analysis. The production-only LCOH is taken as the average locational marginal price of hydrogen in Norway, whereas the LCOH including conversion and export is taken as the average locational marginal price of ammonia (given in kgH_2-equivalent units in terms of energy content) in the model node representing continental hydrogen demand. The total electricity requirement includes the electricity requirement for ammonia synthesis (16.3 TWh in total) and, in Scenarios B and C, the electricity requirement for hydrogen electrolysis. The average electricity cost represents a demand-weighted average of the locational marginal prices of electricity in the Norwegian model nodes.

	Scenario A (*Business-as-usual*)	Scenario B (*Moderate onshore*)	Scenario C (*Accelerated offshore*)
Norwegian LCOH (production only) [€/kgH_2]	2.05–2.63	2.95–3.83	3.78–5.17
Norwegian LCOH (incl. conversion to ammonia and export) [€/kgH_2-equivalent]	3.50–4.27	4.61–5.72	5.54–7.25
Total electricity requirement for exports [TWh]	16.3	126	126
Average electricity cost (Norway) [€/MWh]	48.9–62.0	56.5–71.2	51.5–65.9
Onshore wind capacity, Norway [GW]	8.4–25.4	34.5–62.7	12.6–19.9
Offshore wind capacity, Norway [GW]	0–8.8	0–13.0	27.9–33.5
Bottom-fixed [GW]	*0–8.8*	*0–9.9*	*0–19.7*
Floating [GW]	*0–4.1*	*0–4.1*	*10.6–32.5*
Onshore wind land area demand [km^2]	979–2959	4007–7291	1462–2309
% of open land areas in Norway[a] [44]	0.9–2.6%	3.6–6.5%	1.3–2.1%

[a] Open land areas in 2023, defined as undeveloped areas excluding forest, marshland, permanent snow, ice and glacier areas, as well as bodies of water [43].

drop of 1% in electrolyser efficiency could lead to an average cost increase of €0.042/kgH_2 in Scenario B whereas the increase in hydrogen cost is €0.052/kgH_2 in Scenario C. Natural gas cost is the single main factor determining the cost of hydrogen production in Scenario A (*business-as-usual*), where an 1% increase in natural gas prices may lead to an average increase of €0.016/kgH_2. The next two important factors are the capital cost for SMR installation and CO_2 sequestration cost (including transportation). In Scenario B, the cost of hydrogen production is highly dependent on the capital cost of onshore wind, where an increase of 1% leads to an average increase of €0.045/kgH_2. The export capital costs refer to the cost of converting hydrogen into the exportable ammonia.

The model differentiates between bottom-fixed and floating offshore wind, and the final LCOH is highly sensitive to the cost of floating offshore wind in Scenario C (*accelerated offshore*). The reliance on floating offshore wind is explained by the relatively low potential for bottom-fixed offshore wind by the Norwegian coast, with only about 55 GW of maximum installable capacity available along the entire Norwegian coastline (based on a maximum depth of 60 m and density of 2 MW/km^2 for bottom-fixed offshore wind), less than a third of which is located below 62°N — the preferred location for offshore wind in the model (see Fig. 6).

Table 4 summarises the production and shipping costs of hydrogen and its derivatives in the existing literature to Germany. The cost of blue hydrogen production in Norway is higher than in Canada, which could be due partly to the slightly lower carbon capture rate (85% instead of 90%) and gas prices assumed in the latter countries (roughly half of the value assumed in our model). This may be attributed to the fact that the studies were conducted before the recent energy crisis triggered by the

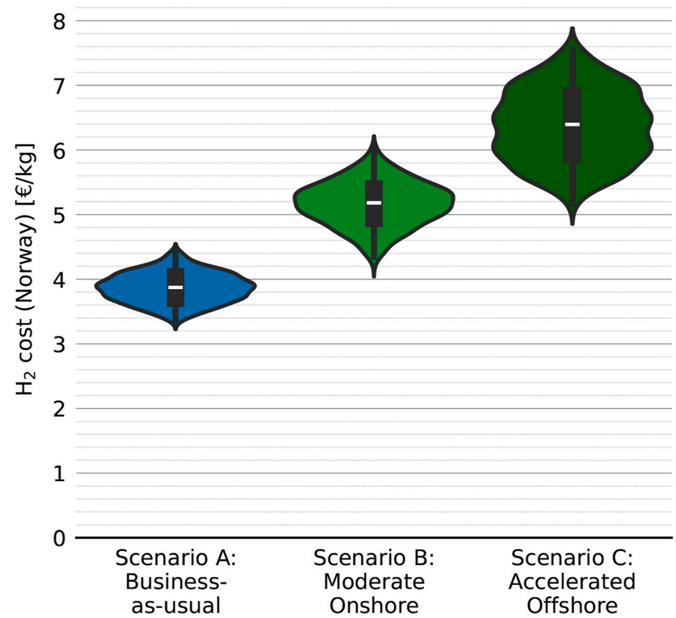

Fig. 3. Distributions of levelised costs of Norwegian hydrogen seen across 500 model runs in each of the three scenarios. These include production, conversion to ammonia and transportation and correspond to the figures in the second row of Table 3. The median costs are marked in white, and the 75th and 95th percentiles are marked with thick and thin black lines respectively. The coloured areas show kernel density estimations for the probability distributions of the costs.

Russian invasion of Ukraine and did not take into account the after-effects of the ongoing war. Adjusting for these effects, Norway's total export cost for blue ammonia is likely to be cheaper than that of Canada.

As for green hydrogen production cost, Norway's cost ranges in Scenarios B (*moderate onshore*) and C (*accelerated offshore*) are higher than those of other countries including Morocco, Argentina, Chile and Australia. This could be attributed to the type of renewable energy technologies used to produce renewable electricity as well as market effects. The Levelised Cost of Electricity (LCOE) of solar PV is lower than onshore and offshore wind, which results in lower electricity costs. Given the high sensitivity of hydrogen production cost to electricity prices, it is not surprising that Morocco, Argentina and particularly Chile could have a cost advantage over Norway for green hydrogen production. Further, we assume the use of proton exchange membrane (PEM) electrolysers in our study as they allow for a modular scale-up of the operation — being able to start with small units and scale up later can reduce investment risk. Nevertheless, as shown in Fig. 4, the impact on the overall cost contributed by the electrolyser capital cost is small compared to that of the electrolysis efficiency rate. Moreover, Norwegian electricity prices, though falling from 2023-levels, are still affected by high prices in neighbouring countries (see also Table 6); such effects are not taken into account in the studies considered in Table 4. Overall, green ammonia exports from Norway in both Scenarios B and C are less cost-competitive than the considered alternatives.

3.2. How fast do we need to ramp up renewable energy expansion?

Diving into the green hydrogen scenarios, Fig. 5 shows the installed capacities of onshore and offshore wind required in Norway across the three different scenarios. Scenario A (*business-as-usual*) requires a total installed renewable capacity of 21 GW on average across the sensitivity analysis, of which 8–25 GW (5th–95th percentiles) is onshore wind, depending on the volume of offshore wind installations (0–9 GW, 5th–95th percentiles). The additional electricity generated is used mostly for the decarbonisation of various sectors in Norway, but also

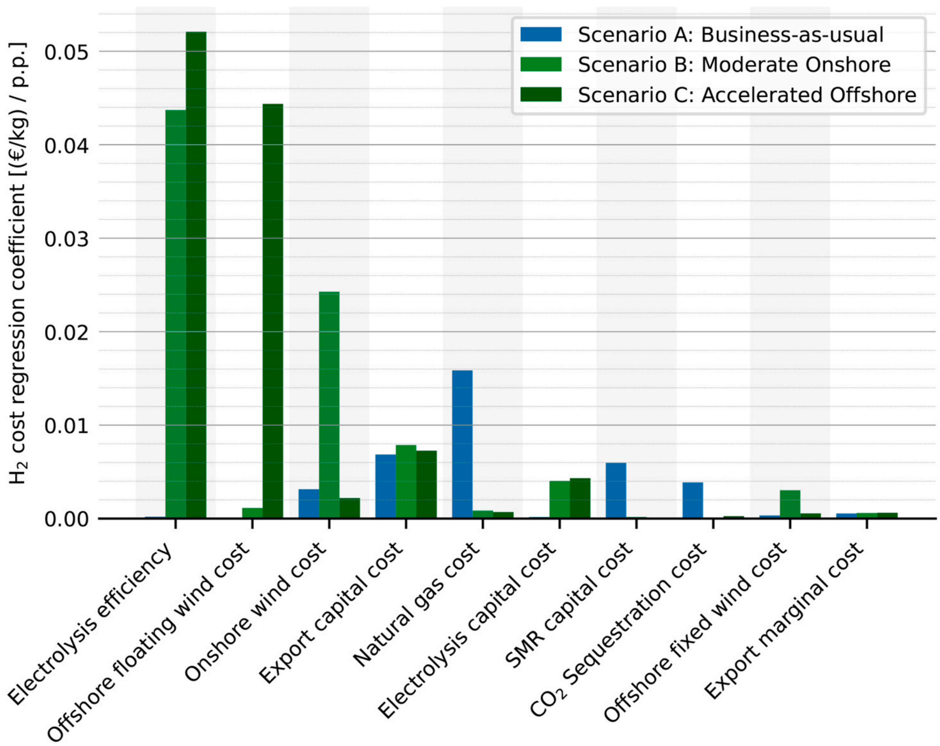

Fig. 4. Sensitivities of Norwegian H_2 export costs in Scenarios A, B & C to variations in technological parameters. The sensitivities are calculated as the coefficients of the parameters in a multi-dimensional linear regression model fitting parameters to H_2 cost. The combination of parameters predicts hydrogen cost linearly with R^2 values of 0.997, 0.981 and 0.998 for the three scenarios respectively. The coefficients are expressed in LCOH (€/kgH_2) per percentage point (p.p.) change in respective technological parameters. For example, the figure shows that in Scenario B (light green), a cost increase in onshore wind of 1% would increase H_2 costs by €0.024/kg on average. For more details on the technological parameters, see Table 2. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

Table 4
Comparison of LCOH at production and delivery between the present study and other comparable studies. All figures are inflation-adjusted to 2023 EUR where necessary. Cost ranges arise from sensitivity analyses performed in the cited studies where applicable. All studies assume Hamburg, Germany to be the European port of delivery. "Electrolysis" is shortened to "Elec.".

Origin	Transport medium	Production method	Hydrogen Production cost [€/kgH_2]	Cost of delivered hydrogen [€/kgH_2]
Norway[a]	Ammonia	Scenario A: SMR + CCS (90%)	2.05–2.63	3.50–4.27
	Ammonia	Scenario B: Elec.	2.95–3.83	4.61–5.72
	Ammonia	Scenario C: Elec. (offshore wind)	3.78–5.17	5.54–7.25
Western Canada[b] [12]	Ammonia	SMR + CCS (85%)	1.85	5.56
	Ammonia	Elec. (onshore wind)	2.68	6.39
Morocco [11]	H_2 pipeline	Elec. (onshore wind & solar)	1.59–3.07	3.54–5.71
Chile [11]	Liquid H_2	Elec. (onshore wind & solar)	1.29–2.53	2.67–4.47
Argentina [45] [c]	Ammonia	Elec. (on- and offshore wind & solar)	–	2.72–4.02
Australia [45]	Ammonia	Elec. (on- and offshore wind & solar)	–	3.32–4.93

[a] Present study. Note that conversion of ammonia to hydrogen upon delivery is not included; cost is in kgH_2-equivalent in terms of energy content.
[b] Based on 2020 conversion rate 1 EUR = 1.53 CAD (https://www.ecb.europa.eu/).
[c] The numbers given for this study likewise do not include conversion of ammonia to hydrogen at destination.

Table 5
Land use requirement for onshore wind installations in different scenarios by region, following the results presented in Fig. 6. We assume 8.6 km^2/MW to calculate the area. The regions are defined as in Fig. 6.

	2023		Scenario A (*business-as-usual*)		Scenario B (*moderate onshore*)		Scenario C (*accelerated offshore*)	
	GW	Area [km^2]	GW	Area [km^2]	GW	Area [km^2]	GW	Area [km^2]
North	0.7	82	5.6	659	8.9	1035	7.4	860
Central	1.8	204	0.9	101	2.8	326	0.9	105
South	2.5	296	13.1	1528	40.6	4721	8.1	942
Total	**5.0**	**582**	**19.6**	**2278**	**52.3**	**6082**	**16.4**	**1907**

ammonia synthesis (16.3 TWh annually). The electricity for blue hydrogen production is assumed to be generated using natural gas and thus will not impact the current electricity grid. Nevertheless, the need for renewable electricity expansion is significant, compared to the current onshore wind capacity of 5 GW [46]. Without offshore wind installations, the deployment of onshore wind turbines would need to be

Table 6
Average electricity prices by region in different scenarios compared to 2023. 5th to 95th percentile ranges across the sensitivity analysis are shown in brackets. The regions "North", "Central'' and "South" are defined in Fig. 6 for Scenarios A–C, whereas they correspond to the respective (group of) Nordpool pricing zones for 2023 prices.

€/MWh	2023	Scenario A *(business-as-usual)*	Scenario B *(moderate onshore)*	Scenario C *(accelerated offshore)*
North	30	56 *(50–62)*	64 *(56–70)*	59 *(52–66)*
Central	49	56 *(49–62)*	67 *(58–74)*	59 *(51–66)*
South	90	56 *(49–63)*	64 *(56–71)*	59 *(52–66)*
Overall average	70	56 *(50–63)*	64 *(56–71)*	59 *(52–66)*

increased by 2030 by 5 times compared to the installations done in the last 6 years, during which 925 wind turbines with a total capacity of 3.8 GW were installed [46].

To meet the demand for green hydrogen exports in Scenario B (*moderate onshore*), the total installed renewable energy capacity needs to increase more significantly than in Scenario A as this requires the generation of additional electricity for the electrolysis process (around 109 TWh a year). This entails an increase in the onshore wind capacities to at least 27 GW with some offshore wind installations, or to as high as 64 GW without any offshore wind installation (see Fig. 5). Although offshore wind installations are permitted in Scenario B, the model consistently proposed higher proportions of onshore wind installations than offshore wind installations as the former has a lower LCOE. On the other hand, Scenario C is constrained to only use power from offshore wind plants to produce the green hydrogen and sees a minimum offshore wind capacity of 28 GW. This is almost the same as the national ambition of 30 GW for offshore wind installations for 2040 [47] — the present study, however, targets 2030.

Fig. 6 shows the mean deployment of onshore wind and offshore wind in each of the model regions in Norway. In all the scenarios, the model proposed that the majority of the additional RES capacity should be installed in southern Norway. As good wind conditions can be found in the North and South, and marginal export costs (which are higher for exports from the North) are relatively insignificant for final LCOH, the preference for wind power in Southern Norway is likely due to a stronger transmission grid and greater hydropower capacity making it easy to maintain a high capacity factor for electrolysis, as well as avoiding wind power curtailment in periods of high wind power production.

Note that despite the lower demand for electricity in Scenario A, where the energy for blue hydrogen production is assumed to be generated from natural gas, there is still an average of 13 GW of onshore wind power in Southern Norway and about 6 GW in Northern Norway. This is mainly attributed to an increase in renewable electricity demand due to the constraint to meet a 55% reduction in CO_2 emissions. Increased Norwegian wind power production in Scenario A mostly feeds into a combination of partial electrification of transportation and industry. Today's installed onshore wind capacities in Southern Norway and Northern Norway stand at around 2.2 GW and 1.1 GW respectively [46]. This means that decarbonisation is expected to lead to a 6-fold increase in onshore wind power from a cost-minimisation perspective.

To produce green hydrogen, electrolysis plant capacity in both Scenarios B and C needs to reach around 14 GW. Thanks to the abundance of existing hydropower plants in Norway, the electrolysers can leverage the flexibility of hydropower and run at a high capacity factor of around 0.97 to balance the intermittent energy production inherent to variable renewable energy technologies. This flexibility, also including the transmission grid (including cross-border connections to the UK and continental Europe) is one of the reasons for the model preference for both onshore and offshore wind capacities primarily in Southern Norway, as seen in Fig. 6. In addition, the modelling results include an average of 7.5 GW and 1.2 GW of solar installation in Scenarios B and C respectively, which is not shown in Fig. 6.

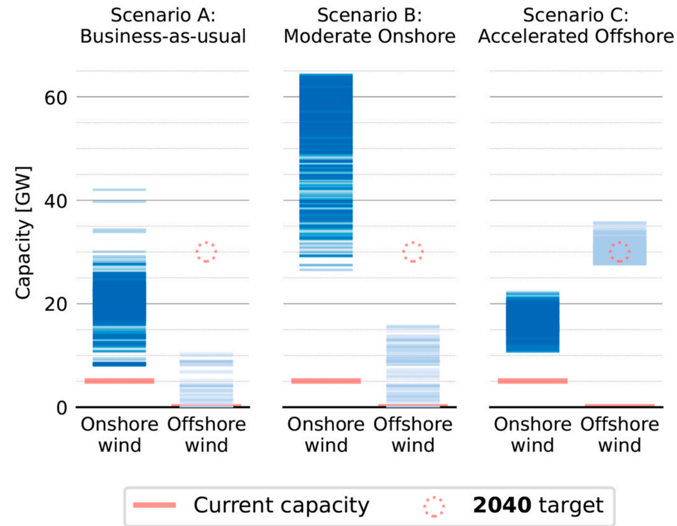

Fig. 5. Installed onshore and offshore wind capacities in Norway across Scenarios A, B & C. The plotted ranges indicate all observed capacities in the sensitivity analysis over 400 model runs.

3.3. Social and environmental impacts

3.3.1. Land use requirement for onshore wind farms

The land area in Norway excluding Svalbard measures about 324,000 km^2, of which 42.5% (equivalent to 138,000 km^2) was classified as "undeveloped open land"[4] in the National Land Resource Map in 2021 [48], a first approximation of which areas could be perceived as suitable for wind power development. Breaking this down by region (using the latitude-based definition from Fig. 6), the open land areas in Southern Norway, Central Norway and Northern Norway are around 58, 000 km^2, 25,000 km^2 and 55,000 km^2 respectively. The deployment of renewable energy technologies requires more land areas than fossil fuel. According to the Norwegian Water Resources and Energy Directorate (NVE), the *directly affected area* ("direkte påvirket areal") of onshore wind installation is estimated to be around 8.6 MW/km^2 [49]. In a study by the same, a country-wide total area of 16,705 km^2 was identified as potentially suitable for wind power development based on a number of exclusion criteria [50].

Based on the average onshore wind capacity needed for ammonia production, the land area required for the installation of the turbines in each of the Scenarios is shown in Table 5. The results show regional differences in the land impacts from renewable energy expansion and electricity impacts on the local communities in Norway, where Southern Norway is expected to be more affected than Northern Norway. In Scenario A (*business-as-usual*), the average of 20 GW of wind installations necessitates around 2278 km^2 of land area, equating to around 2.6% of open land area in Southern Norway and 1.2% in Northern Norway. Scenario B (*moderate onshore*) requires a significant amount of land area that represents about 8.2% of open land in Southern Norway and 1.9% in Northern Norway; the total land use amounts to 36% of the area identified as potentially suitable for wind development by a 2019 NVE report [50]. Scenario C (*accelerated offshore*) shows an

[4] Also known as "snaumark", area code 50 in the National Land Resource Map, corresponding to classes 18 (open firm ground) and 20 (bare rock, gravel and blockfields) in Ref. [44]. This includes areas used for reindeer husbandry. The total of 138,000 km^2 is based on the author's own calculations using the AR250 dataset.

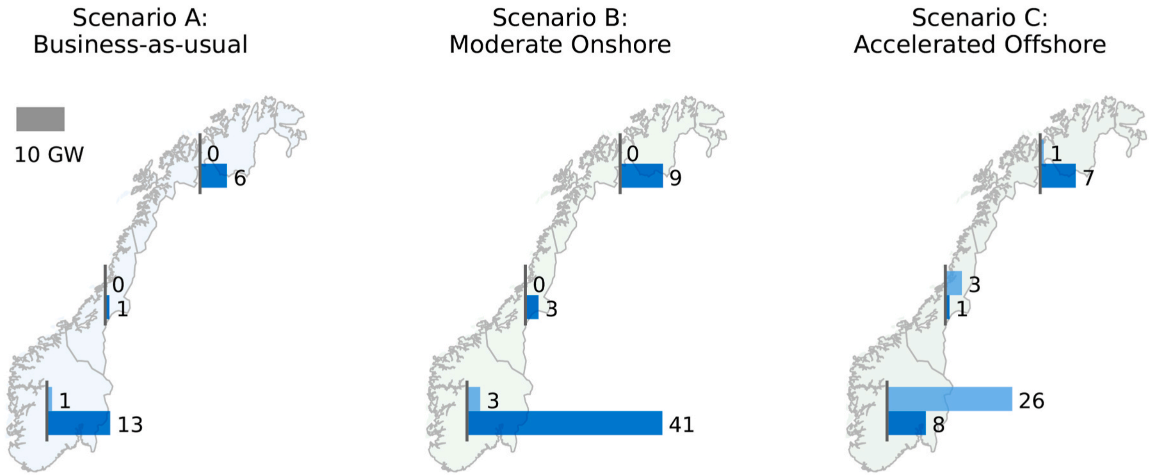

Fig. 6. Spatial distribution of onshore wind (dark blue) and offshore wind (light blue) capacities in Norway (in GW) between the different scenarios. The values shown are averagely over the 500 model runs used for sensitivity analysis. The bar in the top left is shown for scale. The capacities are given for Southern, Central and Northern Norway respectively; the regions correspond to groups of model nodes (as shown in Fig. 2) located south of, between and north of the 63°N and 67°N parallels. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

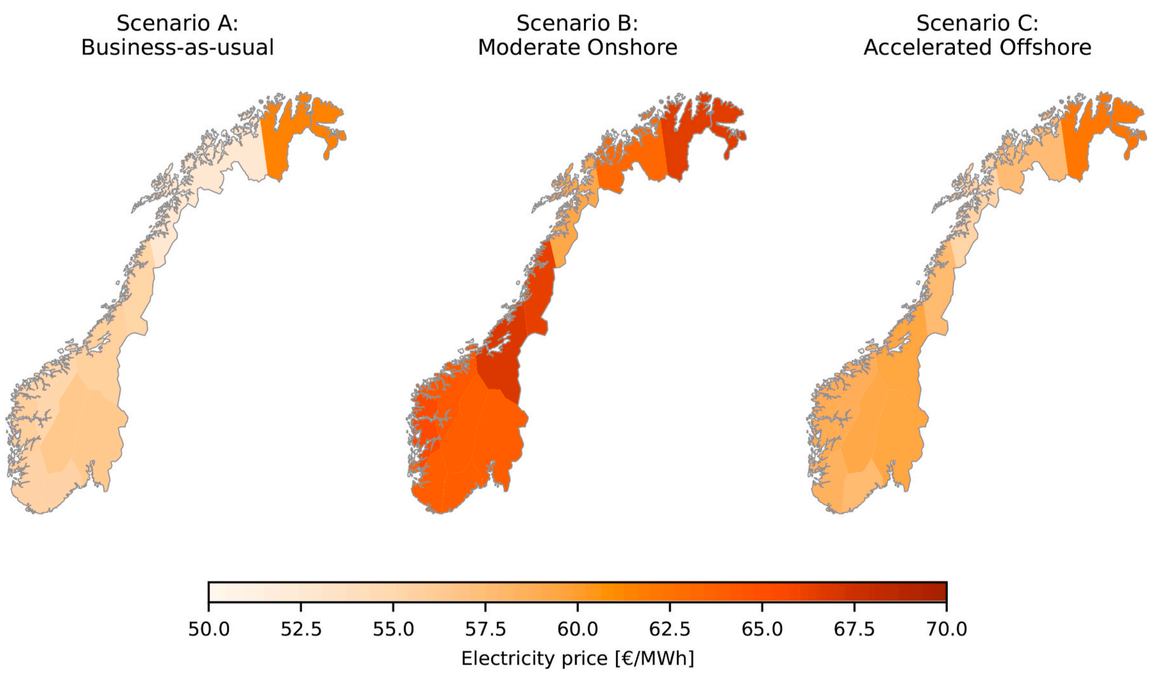

Fig. 7. Yearly mean electricity prices observed in the different scenarios by model region in Norway. These are the average prices observed across all sensitivity analysis model runs for each region. Note that prices are shown for model regions/nodes, not Nordpool pricing zones. See Table 6 for price ranges observed across the sensitivity analysis, presented by aggregated regions.

equal distribution of onshore wind between the South and the North, which represents about 1.6% of open land in each region.

To put things in perspective, the biggest city of Norway, Oslo, measures 454 km^2 in land area. The amount of land needed for reducing Norway's carbon emissions to be in line with its 2030 climate goal would require about 1907 km^2 (as shown in Scenario C), approximately about 4–5 times the size of Oslo. Achieving Scenario B would required a land area of 6082 km^2, that is more than 13 times the size of Oslo. Of this, the green hydrogen export industry requires 4175 km^2, equivalent to 9 times the size of Oslo.

3.3.2. *Electricity prices for the local communities*

The electricity prices in Norway are divided into 5 pricing zones: NO1 (South-east), NO2 (South), NO5 (South-west), NO3 (Central) and NO4 (North). Historically, NO1, NO2 and NO5 tend to share similar electricity prices due to the strong flows of electricity between the zones, but higher than in NO3 and NO4, due to the close connection with the grid in Continental Europe. In 2023, the average electricity price in Southern Norway (NO1, NO2 and NO5) was around €89.77/MWh, whereas the average electricity prices in Central Norway and Northern Norway were €48.54/MWh and €30.24/MWh respectively [51]. Note that the electricity prices include taxes except for Northern Norway where the electricity tax of 25% is exempted.

Electricity prices can be extracted from energy system optimisation models as the shadow prices of the set of constraints enforcing that electricity demand is met; these are optimisation outputs similar to electricity market prices. The results can indicate general trends but don't necessarily capture all market dynamics governing current-day electricity prices (see also Limitations). Fig. 7 shows that in all scenarios, the regional differences in electricity prices become less prominent in 2030 compared to the average electricity prices in 2023. At the national level, the overall mean electricity prices for all scenarios are lower than in 2023. However, the implications for each region vary. Taking the mean value of the electricity prices calculated in Scenario A (*business-as-usual*), the increase in renewable energy installations in the south is expected to lead to a drop in the average electricity prices by −38% versus 2023, whereas the electricity prices in Central Norway are likely to increase by around 14% (refer to Table 6). Across all the scenarios, Northern Norway's electricity prices are expected to almost double the electricity prices in 2023.

The large increase in electrolysis-induced electricity demand in Scenario B (*moderate onshore*) leads average Norwegian electricity prices to jump from 50 to 63 €/MWh to 56–71 €/MWh compared to Scenario A. Even then, Southern Norway's electricity prices in 2030 are expected to be lower than in 2023 in Scenario B. Both Central and Northern Norway are expected to face higher electricity prices compared to 2023 prices and Scenario A. Green hydrogen exports are thus seen to have an equalising effect on electricity prices, with any low-price regions being exploited for exports by the model until the price matches other regions. Some of the price equalisation may however also be due to limitations in modelling transmission bottlenecks.

Shifting electricity production to offshore wind (Scenario C) is shown to be feasible, but necessitates total annual subsidies for offshore wind of €3.2 billion on average, equivalent to subsidising each kg of H_2 by €1.62, or a feed-in tariff of €27.9/MWh for offshore wind.[5] The subsidy leads to lower electricity prices in Scenario C than in Scenario B, even if the total system cost (and LCOH) is significantly higher. The total required subsidy could be compared with the willingness to pay around €22.4 (NOK 253) per household per month to shift wind production from onshore to offshore shown in Ref. [52], which would amount to a total annual subsidy of approximately €6,99 billion (counting 2.6 million households in Norway). However, the same study notes a comparable willingness to pay to ensure that wind development serves local or national needs but is not used for export purposes. Ensuring local/national ownership induces an even higher willingness to pay.

3.3.3. *Alternative Scenario B for more onshore wind expansion in Northern Norway*

In Section 3.3.1, the modelling results of Scenario B proposed a significant number of onshore wind turbines to be installed in Southern Norway, based on a cost-minimisation principle. To explore alternatives, we imposed a sequence of limitations on the onshore wind capacity in the Southern half of Norway (here defined as south of 65°N): 5, 10, 20, 30, 40, 50 and 60 GW (Fig. 8). The results show that southern onshore wind can be replaced by a combination of onshore wind in the North as well as offshore wind in the South; the balance between the two is relatively sensitive to technology costs. This shift, however, results in a higher LCOH on average, rising by €0.57/kgH_2 from the least to most restrictive case and further threatening the profitability of Norwegian green hydrogen.

3.4. *Limitations*

Our model is based on a single weather year (2013) rather than multiple weather years. Previous research has shown that total system costs resulting from a capacity expansion model as in this study can vary significantly between weather years [30], meaning that the present study is likely to underestimate weather-induced variations in green hydrogen price. Moreover, the impacts of climate change are not reflected in our results. The aggregated nature of our model means that transmission bottlenecks may be imperfectly captured. The geographical scope is limited to Norway and neighbouring countries, meaning that the energy sectors of neighbouring countries themselves (and especially energy trade outside the model region, e.g. with France) is not perfectly modelled. Our model has perfect foresight over the entire year of operations, meaning that especially hydropower may be operated in a more optimal than realistic fashion. Moreover, our model does not include real-life time-dependent constraints on hydropower reservoir levels and downstream river flow, meaning that reservoir hydropower in the model can operate more flexibly than in real life. These factors combined could induce systematic biases in total system cost, electricity prices and LCOH.

Some assumptions regarding the choice of hydrogen pathway to model are open to uncertainty and could not all be subjected to sensitivity analysis. We choose to disregard the cost of and losses involved in ammonia cracking to produce hydrogen at the destination port; as explained in Section 2.1 this is because green hydrogen is often expected to be used as a feedstock for the production of liquid fuels such as ammonia. Still, this choice may cause final costs to be underestimated. On the other hand, we limit our analysis to ammonia shipping as the hydrogen transportation vector; hydrogen exports costs would improve once a pipeline is in place. These systematic effects are not considered in the determination of likely cost ranges based on sensitivity analysis.

Energy demands of various sorts (electricity, gas, heat, oil) in Norway and neighbouring countries are estimated for 2030 in this study using the sector-coupled version of PyPSA-Eur but left unchanged save for the additional 2 Mt hydrogen demand. This projection is, however, subject to uncertainty; a specific uncertainty pertaining to Norway is the degree of electrification of the offshore oil and gas industry. This uncertainty has not been specifically investigated in the present study but could impact especially the results on minimum onshore/offshore wind capacities required in Norway while meeting climate targets and not becoming a net electricity importer.

4. Discussion

4.1. *Norwegian cost-competitiveness as a blue hydrogen exporter*

As a blue hydrogen exporter to the EU, the analysis shows that Norway has some price advantage over Canada, mainly due to the transportation cost. The cost of production of hydrogen in Canada in Ref. [12] was calculated based on half the value of the natural gas prices assumed in our model and a lower carbon capture rate of 85%. Given that natural gas prices represent 45–70 % of grey hydrogen production [53] and the sensitivity of hydrogen production cost to natural gas prices, adjusting for these prices could allow Norway to be even more cost-competitive in blue hydrogen exports to the EU. While the transport of the CO_2 and sequestration in depleted fields is included in our model, this was computed as a fixed cost per ton of CO_2 at around €36.50/tCO_2, due to the uncertainty of the distance between the source of CO_2 and the potential CO_2 storage site. This cost is comparable to that estimated by a recent pilot CCS study, where the shipping costs of CO_2 in Norway by a CO_2 ship over a distance of between 433 km and 600 km was between €18–42/tCO_2 [54](€0.16–0.37/kgH_2 based on 8.9 $kgCO_2/kgH_2$ [55]).

The SMR in Scenario A involves an annualised investment of €1.5 billion, which is expected to capture about 23 Mt of CO_2 annually; almost half the total territorial GHG emissions in Norway in 2022 [56].

[5] The offshore wind subsidy is calculated based on the dual variable of the model constraint that all electricity used for Norwegian hydrogen electrolysis comes from offshore wind on a net yearly basis (constraint 4 in Section 2.3); the value of this dual variable is €27.9/MWh on average across the cost sensitivity analysis. This is an output of the optimisation, and indicates how binding the offshore wind constraint is; it is equivalent to a subsidy in the sense that €27.9/MWh is the feed-in-tariff for offshore wind power production which would make it cost-optimal to build enough offshore wind power to supply all electrolysis demand, as per Scenario C. The value was multiplied by the total offshore wind power production figure to arrive at the total subsidy figure of €3.2 billion.

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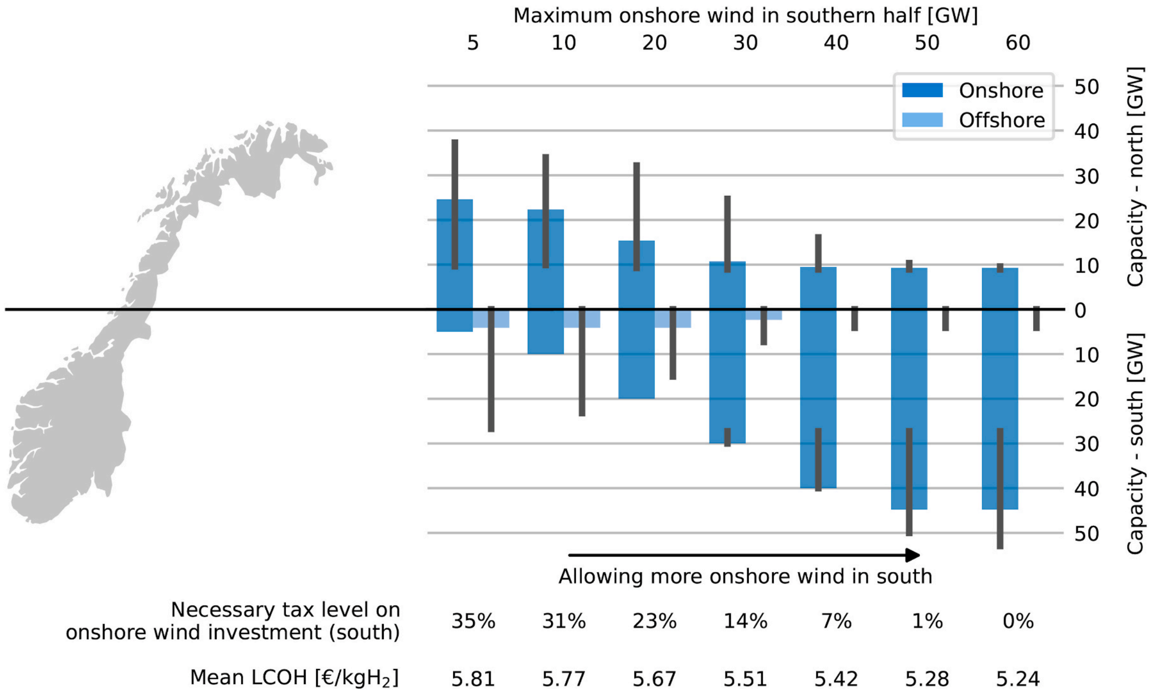

Fig. 8. Alternatives for the distribution mix of renewable energy capacity expansion for Scenario B. For the purpose of this figure, cost-optimisations for Scenario B (*moderate onshore*) are run with various caps on the total allowed onshore wind capacity in the southern half of Norway (south of 65 N), from 5 GW to 60 GW. The bar chart shows the resulting distribution of onshore wind and offshore wind installed south and north of 65 N, showing that onshore wind investment could be shifted to the north of Norway to some extent. The error bars show the 5th–95th percentile ranges over a cost-sensitivity analysis as described in Section 2.4. The first of the bottom two rows of the figure indicates the tax level on the onshore wind in the southern half of Norway required to make the given distribution profitable. These figures are derived from the shadow prices of the regional capacity constraints; outputs of the optimisations which indicate (in €/MW) how much the total system cost would be reduced if one additional MW of onshore wind were allowed in the south of Norway. The shadow price is also equivalent to the additional tax on onshore wind in the south (in €/MW) which would make the given total capacity cost-optimal. Dividing this number by the assumed capital cost of onshore wind (Table 2) gives a relative figure. The second row displays the resulting mean LCOH.

Despite a high CO_2 capturing rate of 90% at steam methane reformation plants, the blue hydrogen production would nevertheless result in 2.6 Mt of CO_2 emissions to the atmosphere. Based on an assumed carbon tax of €200/tCO_2 in 2030 [57], p. 14], the total carbon tax per year amounts to a hefty €4.6 billion. For reference, the shadow price of CO_2 in our model[6] is €85.6/tCO_2 in Scenarios B & C, and €89.1/tCO_2 in Scenario A — this is the model-wide carbon tax that would be required to lower emissions by 55% in the model.

Moreover, the feasibility of blue hydrogen export is contingent on the infrastructure for CO_2 transport from mainland Norway to potential CO_2 storage sites, which do not exist with the storage volumes required for this study today. The transport and storage of CO_2 in subsea reservoirs in Norway is subject to the Storage regulations of 5 December 2014 No. 1517 [58]. In 2022, two exploration licences for CO_2 storage were awarded, one in the North Sea, (outside of Bergen in the South) and one in the Barents Sea (outside of Hammerfest in the North) [59]. The exploration licences awarded are valid for four and three years respectively, and can be extended up to a maximum of ten years [58]. An exploitation licence may subsequently be granted before any installation of the necessary infrastructure can begin. When this will happen will depend on the results of the exploration licences, which are expected to expire in 2025 and 2026.

4.2. Norwegian cost-competitiveness as a green hydrogen exporter

Norway has historically enjoyed relatively cheaper electricity prices than continental Europe and this is expected to remain so in 2030 [60]. This implies that green hydrogen imported from Norway could be cheaper than that produced in continental Europe. Furthermore, the demand for hydrogen in Germany is higher than can be produced domestically, which makes Norway's green hydrogen export attractive. However, compared to other potential green hydrogen exporters like Chile, Morocco, Australia and Argentina, Norway is less cost competitive, mainly due to the electricity generation from solar PV, whose LCOE is known to be lower than onshore and offshore wind, as well as possibly electricity market effects.

Nevertheless, Norway has a long-standing relationship with the EU as an important strategic trading partner and the joint-statement on hydrogen cooperation between Norway and Germany indicates that this will likely remain unchanged [19]. Therefore, Norway could still be an important green hydrogen exporter for the EU, but the size of the market share depends highly on the amount of renewable energy Norway can generate in the next 6 years.

4.3. Energy policy implications

With fast-depleting petroleum resources [61], Norway needs to explore new avenues to secure a post-petroleum future. Given the dependence on gas to produce blue hydrogen, it is destined to play a temporal role in the low-carbon energy future. In the long-run, the EU plans to reduce its dependence on fossil fuel, which makes green hydrogen a better market to tap into. As the results in Section 3.3.1 show, substantial amount of land is needed to develop an export market based on green hydrogen using onshore wind. Careful planning and allocation of resources is required to ensure efficient use of land which provides long-term benefits to the communities in Norway that can last beyond the petroleum future. According to Norway's power system

[6] The shadow price of CO_2 is an optimisation output, being the dual variable of the global CO_2 emissions constraint. Its level indicates the marginal cost of reducing total CO_2 emissions by one tonne.

operator, Statnett, the electrification of petroleum offshore platforms requires about 20 TWh [62]. Based on an average wind capacity factor of 30%, this equates to about 7.6 GW onshore wind capacity (884 km^2 of land area), accounting for almost half of the decarbonisation power needs assumed in our model for 2030. If this power demand can be supplied by either the use of gas with carbon capture or with offshore wind power, this would provide the petroleum industry the opportunity to demonstrate its leadership in both technologies. Meanwhile, the land-use impact of the green hydrogen export industry would be reduced. This would be a win-win solution for Norway to develop three potential markets in the post-petroleum future.

The expansion of renewable energy is needed to ensure that overall electricity prices will remain competitive in Norway for Norwegian end-users in spite of the production of green hydrogen exports. If the roll-out of renewable energy follows the cost-optimisation results, the electricity prices between the regions will be more homogeneous, which would benefit Southern Norway the most. Central Norway will see some increase in electricity prices and Northern Norway would lose its long-time advantage of being the region with the lowest electricity prices. Overall, Norway will risk eroding its competitiveness as a potential hydrogen exporter, if the production of blue and green hydrogen for export is not followed by the expansion of renewable energy proposed by the model. This will also likely affect other energy-intensive industries in Norway which are dependent on cheap electricity prices to compete in the global market.

The lower electricity prices in Southern Norway in the scenarios may be due to the proposed installation of most of the onshore and offshore wind turbines in the South of Norway. Part of the reason is due to the weak transmission network in Northern Norway. However, concentrating the growth of new industries in Southern is likely to accentuate the problem of declining population in Northern Norway [63]. Maintaining a permanent population in Northern Norway is crucial for Norway's national security due to its proximity to the Russian border, a concern that has intensified following the war in Ukraine. Therefore, it is essential to promote more equitable distribution of renewable energy development across Norway. This can be achieved by upgrading the existing transmission grid in the North and providing government grants and incentives to enhance economic viability of onshore and offshore wind parks in Northern Norway.

Historically, onshore wind parks were often built in windy and exposed, but scenic locations due primarily to political concerns for power supply and cost-effectiveness, rather than less cost-effective but visually less intrusive locations [64]. This fostered the perception that public opinion about nature conservation concerns were ignored, thereby fuelling popular resistance against onshore wind [64]. Part of the resistance may also be due to the perceived erosion of local self-determination rights, where national and/or international interests take precedence over local concerns [65]. A case in point is the Fosen Vind conflict with the Sámi reindeer herders, where the Supreme Court of Norway ruled that the concession of two wind parks of the former violated the rights of the former as indigenous people to conduct their cultural practices, reindeer husbandry [66]. This case proved that failing to address these concerns adequately could be costly for all stakeholders; the reindeer herders suffered a significant loss of reindeer winter grazing pastures [66]; the international credibility of the Norwegian government as an environmental leader was tarnished, which could affect its prospects securing a market for its green products including green hydrogen; the financial compensation to the former will cost Fosen Vind millions of kroner [67]. The ruling further implies that future wind power expansion in Central and Northern Norway will face a permanent constraint from the spatial sovereignty claims of the indigenous community [65], making it more difficult to realise all three scenarios in these regions.

Nevertheless, while the public opinion towards onshore wind still trends negatively, it has improved slightly since the war in Ukraine [68, 69]. This may be because of the perceived need for greater energy security following the energy crisis in Europe resulting from the war. The reverse trend in public opinion demonstrates that it is not static and could evolve depending on people's perceptions of the need for renewable energy expansion. Future energy policies may thus have better success in expanding renewable energy if the locals' needs and concerns are identified and addressed adequately prior to implementation.

Compared to onshore wind, offshore wind is more well-received by the public across all the regions in Norway, with more than 70% positive responses in a national survey on opinions about offshore wind [23,52]. Although bottom-fixed offshore wind is assumed to cost almost half of that of floating offshore wind (see Table 2), the modelling results suggested significantly more installations of the latter. The reason is due to the limited amount of suitable area (sea beds of less than 60 m deep) for bottom-fixed offshore wind installations. In any case, floating offshore wind is socially and politically more popular, not least due to less visual impact on the seascape and lower negative environmental impacts [70]. Floating offshore wind technologies are seen as more compatible with the existing Norwegian energy political paradigm thanks to the transferable competences and knowledge from the petroleum and maritime industries [70]. The distribution of offshore wind installations suggested in the model is similar to that of the allocated areas for offshore wind installations in Southern Norway [71] and the potential areas identified as technically feasible with minimal risk of conflicts with other sea users by NVE [72], where thirteen out of twenty are in Southern Norway. The results show that subsidies amounting to €27.9/MWh would be needed to make Norwegian offshore wind competitive with onshore wind. This is double the amount of subsidies that is allocated to the recently auctioned 1500 MW floating offshore wind project Sørlige Nordsjøen II, that has a lifetime cap of 23 billion NOK [73] which translates to an expected €13.9/MWh (assuming a lifetime of 20 years and capacity factor of 0.559 [74]). The development of a green hydrogen-based export market in Norway depends on both onshore and offshore wind expansion. To accelerate the development of the offshore wind, thereby securing its market share as an important supplier of green hydrogen export to the EU, more financial support is needed from the Norwegian government.

5. Conclusion

The modelling results show that all the scenarios are technically and economically feasible. However, each scenario requires some trade-offs between the short-term and long-term costs and benefits. While Norway seems to have a cost advantage over its competitors for blue hydrogen exports, this entails the continued dependence of natural gas, which is fast-depleting in Norway. To secure a post-petroleum future, Norway needs to leverage its technological competencies and other resources to accelerate the development of new industries. As leaders in both CCS and offshore wind technologies, the Norwegian petroleum industry is well-positioned to decarbonise its offshore platforms and produce both blue and green hydrogen at large scale, without significant need for electricity from the mainland grid. Succeeding in the feat would allow the industry to demonstrate the viability of both technologies and gain a foothold in exporting those technologies globally.

If the annual power from Norway's mainland grid meant for decarbonising offshore platforms (20 TWh) is used for developing new industries like green hydrogen export, the amount of land area required for onshore wind expansion will be reduced by 884 km^2 (about twice the size of Oslo). Nonetheless, a significant expansion of onshore wind installations will be necessary until offshore wind technology is mature, to maintain relatively low electricity prices for both existing and new energy-intensive industries, such as green hydrogen export. While the model favours the installation of onshore wind turbines in Southern Norway based on cost-optimisation principles, developing new industries in Northern Norway may help address the problem of declining population and enhance Norway's national security in the North, which shares the border with Russia. Therefore, it is critical to promote a more equitable distribution of renewable energy development across Norway. This may be achieved through upgrading the existing transmission infrastructure and providing government support schemes to enhance the economic viability of onshore wind turbines in the North. Further, the development of renewable energy capacity should proceed with adequate care and attention to locals' needs and concerns as failure to do so can be very costly for all stakeholders.

Lastly, if Norway wants to gain a foothold as an important green hydrogen exporter to the EU, it is essential to advance the technological maturity of offshore wind, particularly floating offshore wind. Our results show that the current subsidies of ~€14/MWh for the offshore wind industry is insufficient. A doubling of the subsidies is needed to make Norwegian offshore wind competitive with onshore wind.

Data and code availability

All data and code needed to reproduce the results and figures in this work can be found at https://github.com/koen-vg/pypsa-eur/tree/hydrogen-exports-v0.1.

CRediT authorship contribution statement

C. Cheng: Writing – review & editing, Writing – original draft, Visualization, Methodology, Investigation, Formal analysis. **K. van Greevenbroek:** Writing – review & editing, Writing – original draft, Visualization, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **I. Viole:** Writing – review & editing, Writing – original draft, Methodology, Investigation, Formal analysis, Data curation, Conceptualization.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Isabelle Viole reports financial support was provided by European Union (Horizon 2020). If there are other authors, they declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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