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Trade-offs between Hydrogen and Electricity Infrastructure

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How to connect energy islands: Trade-offs between hydrogen and electricity infrastructure

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ABSTRACT

In light of offshore wind expansions in the North and Baltic Seas in Europe, further ideas on using offshore space for renewable-based energy generation have evolved. One of the concepts is that of energy islands, which entails the placement of energy conversion and storage equipment near offshore wind farms. Offshore placement of electrolysers will cause interdependence between the availability of electricity for hydrogen production and for power transmission to shore. This paper investigates the trade-offs between integrating energy islands via electricity versus hydrogen infrastructure. We set up a combined capacity expansion and electricity dispatch model to assess the role of electrolysers and electricity cables given the availability of renewable energy from the islands. We find that the electricity system benefits more from connecting close-to-shore wind farms via power cables. In turn, electrolysis is more valuable for far-away energy islands as it avoids expensive long-distance cable infrastructure. We also find that capacity investment in electrolysers is sensitive to hydrogen prices but less to carbon prices. The onshore network and congestion caused by increased activity close to shore influence the sizing and siting of electrolysers.

1. Introduction

Offshore wind energy in Europe is developing fast, and plans to build large capacities in the available waters are evolving rapidly; see for example the recent Esbjerg and Marienborg declarations of the littoral states of the North and Baltic Seas. Anticipated cost reductions in the technology and avoiding not-in-my-back-yard issues create a major opportunity for supporting the decarbonisation efforts in Europe. Together with photovoltaic (PV) generation, large-scale offshore wind energy has been declared to fill the power supply gap that the shutdown of nuclear and fossil fuel plants will leave behind [1]. Some countries have made considerable progress over the last decade. For example, the German electricity system saw a wind share of 24.4%, and a total intermittent RES share of 32.9% in 2020 [2]. The integration of these significant RES shares has been relatively easy to manage, refuting older predictions of disruptions in the reliability of the power system due to increasing shares of fluctuating sources [3,4]. However, this integration still causes higher costs and curtailment [5] that are undesirable and hinder the decarbonisation of the energy system.

Among the solutions are the provision of flexibility by grid extensions, storage technologies, and sector coupling [6,7]. With the publication of the hydrogen strategy, there are major plans in the European Union (EU) to create a hydrogen economy and develop the necessary conversion capacities, including the extension of power-to-gas (PtG) via electrolysis. PtG can serve both purposes: providing flexibility to the electricity system and producing hydrogen to meet demand from other sectors like industry and transportation. When wind farms are moved offshore, production will be affected by fluctuations at sea. To balance those, electrolysis can also be moved close to the generation to so-called *energy islands*.

Energy islands are a European-born idea. The term is typically used for projects in the waters of Denmark and the UK, e.g., the North Sea Wind Power Hub or VindØ. The design of these islands is currently under development, but Fig. 1 shows early ideas for energy islands that host conversion equipment for sector coupling, such as electrolysers [8]. Energy islands are expected to be valuable for providing demand-side flexibility by electrolysis to reduce curtailment, lower stress on the electricity grid, and produce hydrogen offshore for the industry. In addition, they can serve as inter-country electricity connections, which are beneficial for balancing electricity flows [9]. Besides the electricity- and hydrogen-focused projects in Denmark (VindØ and Bornholm) and the North Sea Wind Power Hub, AquaVentus has gathered more than 90 partners to develop a related family of projects

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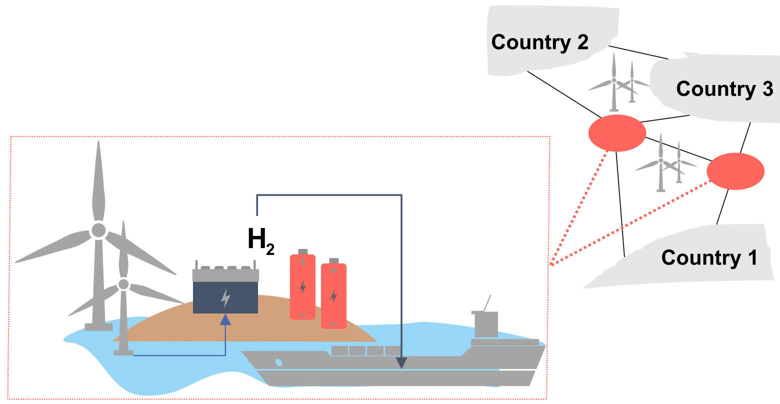


Fig. 1. An abstract sketch of an energy island following first visions presented in [10]. Source: Lüth [8].

around the German Island of Heligoland. Here, 10 GW of offshore wind capacity will be developed by 2035 for the offshore production of hydrogen, including the necessary transportation infrastructure. In this case, though, no electricity connection to shore is currently envisaged.

With this paper, we contribute to the discussion of how to design and plan offshore energy infrastructure, specifically around energy islands, and analyse the trade-offs between offshore electricity and hydrogen infrastructure. Our guiding research question asks how energy islands can be integrated with onshore energy systems and what the system implications of such an integration would be. With the help of an integrated capacity expansion and electricity dispatch model, including a detailed grid representation, we identify economically viable investment options in cables to and between energy islands, and in electrolysers offshore and onshore. We find that offshore electrolysis reduces the need for investment in expensive long-distance cables between offshore wind sites and the mainland to prevent curtailment of wind generation. The current cost of electrolysers in combination with the assumed hydrogen price make it worth using existing nuclear generation for hydrogen production. Investments are sensitive to future hydrogen prices but less so to an increase in CO_2 prices.

The remainder of this paper is structured as follows: Section 2 presents literature on offshore energy systems, system modelling, and electrolysis. In Section 3, we describe the model framework, and Section 4 provides the background of the case study, the data sources, and data curation. Results, discussion, and a sensitivity analysis are given in Section 5. We summarise the main findings and provide an outlook on future research in Section 6.

2. Literature and background

Energy islands are seen to establish offshore in centres of large-scale wind power production. The literature on this topic is not extensive yet but builds on the idea of setting up *power link islands* in a meshed offshore grid [11]. Meshed offshore grids describe the connection of countries via offshore wind farms and interconnecting offshore wind farms among themselves [12]. Early research on meshed offshore grids has developed model frameworks to analyse the impact of offshore grids [13] and allow project consortia such as Kriegers Flak[1] to examine the impact of interconnected wind farms. Connecting wind farms and countries at the same time also takes market integration one step further. Traditionally, wind farms are connected only to the country they were built in, or there are radial connections between two countries that act as interconnectors. In a meshed grid, those two traditional structures converge towards interlinked systems [14]. Interconnection has been called a pillar of renewable energy systems and leads to greater utilisation of renewable resources [9]. Market integration will influence welfare and price development in the connected countries. Early studies agree that offshore grids increase welfare [15,16]. The benefits, however, are allocated asymmetrically among the connected countries: suppliers in high-price areas and consumers in low-price areas will see some negative impacts [16]. The idea of energy islands was developed by industrial consortia around 2016 and has a lot of characteristics in common with offshore grids and interconnectors. Like offshore grids, energy islands will affect market prices and welfare.

Tosatto et al. [17] investigate the welfare impacts on the European electricity system of a North Sea energy island. In a setting without sector coupling and with electricity production only, their results show that overall welfare will increase but the distribution of benefits will be asymmetric: consumer welfare will increase while producers' welfare in exporting countries will be adversely affected, which is well in line with the findings for offshore grids. Zhang et al. [18] model offshore wind hubs in the North Sea to decarbonise the Norwegian continental shelf, establishing a cost-minimising, mixed-integer linear investment planning and operations model. They develop scenarios for investment into renewable generation, storage, electricity transmission, and offshore hubs with hydrogen conversion equipment under specific CO_2 prices and argue that offshore wind and a cable connection to shore can halve current emissions in a scenario of moderate CO_2 prices.

Singlitico et al. [19] were the first to analyse the combination of electricity and hydrogen production from offshore wind plants on large energy islands. In a pre-defined setting of cable connection and electrolyser size, the authors tested different operating modes in which conversion to hydrogen or transport via electrical infrastructure was prioritised. They find that offshore placement can be advantageous, and that a hydrogen-powered operating mode can reduce the levelised cost of hydrogen to the point that it competes with hydrogen from fossil fuels. Gea Bermúdez et al. [20] find in a capacity expansion model (CExM) that forcing hydrogen offshore will lead to higher system costs and onshore hydrogen production is more likely to be cost-efficient due to patterns following PV generation. Their analysis is based on a zonal market representation with cross-border flows. This approach is likely to underestimate inner-zonal congestion which could lead to an overestimation of electricity flows across zones.

Although analyses of offshore grids, which form the infrastructure for energy islands, are more mature, the role, sizing, and siting of electrolysers have not been explored extensively [21]. In combination with multi-country cable connections, new options for linkages with existing energy systems are opening up. Jansen et al. [22] analyse the role of the *North Sea Wind Power Hub*, an energy island in the North Sea, and iteratively assess the roles of connections by cable and hydrogen pipelines under certain assumptions. In a bottom-up cost assessment, they find that large connected wind generation capacities can make an energy island profitable. But their analysis is based on exogenous capacity assumptions about wind farm and electrolyser sizes. Our study

[1] See Kriegers Flak (2021): en.energinet.dk/Infrastructure-Projects/Projektliste/KriegersFlakCGS.

min day-ahead generation costs
+ cost for electrolysis infrastructure
+ cost for electricity connections
- profits from hydrogen sales

s.t. nodal power balance
generator capacity limits
storage limits
electrolyser production limits
network constraints (DC load flow)

Fig. 2. Schematic overview of our framework. The mathematical equations are found in Appendix A.

makes use of an integrated capacity expansion and dispatch model to endogenise the decision of whether to connect energy islands by cable or pipeline and at what capacity.

3. Methodology

We develop an integrated capacity expansion and electricity dispatch framework with high spatial and temporal resolution and including physical constraints on the power network.[2] The framework is set up as a linear cost minimisation problem and allows for investments in hydrogen production or in cables to connect offshore energy production hubs with either onshore electricity systems or other offshore wind farms. Hydrogen is sold at an exogenously fixed price. This framework was inspired by the techno-economic ELMOD [23] and the cost minimisation approach of a later version of dynELMOD [6]. The capacity expansion module is based on LIMES-EU by Nahmmacher et al. [24] and Alharbi and Bhattacharya [25]. To limit the solution space, exogenous scaling of RES, demand, and thermal generation for a multi-year representation is applied as in [26]. The time series reduction and scaling are based on Göke and Kendziorski [27] and Poncelet et al. [28].

Fig. 2 presents the structure of the framework. The objective is to minimise the costs of electricity dispatch and endogenous capacity expansions in electrolysers and DC power connections to the proposed energy islands. In the dispatch, we include short-run marginal costs for thermal power plants, cost of curtailing load, and a discharge penalty for storage. We subtract income from hydrogen production. RES do not incur marginal costs. Investments in electrolysers and connecting power lines are allowed at specific unit costs. For electrolysers, we include annual operation and maintenance costs. The operational constraints include capacity limits for generators, electrolysers, and storages, and network constraints including a power flow approximation. See Appendix A for a full description of the framework equations. The main endogenous decisions of the framework are the dispatch, the produced quantity of hydrogen, and investment in electrolysers and the cable infrastructure around energy islands and offshore wind parks. For this framework, the grid characteristics of an existing power grid and the generation capacities, profiles, and cost parameters are the limiting factors. Renewable electricity that cannot be fed into the grid or converted into hydrogen, is curtailed.

This capacity expansion framework can be applied to any case setup with combined investment decision into hydrogen and electricity infrastructure. It is implemented in Python and the gurobipy interface and solved with the barrier algorithm in Gurobi v 9.5. In the following, we apply it to analyse the plans for energy islands in the North and Baltic Seas.

[2] The framework and model code used in this paper can be found on GitHub: https://github.com/pauleseifert/NodalMOD/releases/tag/1.0.

4. Energy islands in Northern Europe

The islands are expected to be built close to the Danish island of Bornholm in the Baltic Sea, off the eastern coast of Denmark, on the Dogger Bank in the North Sea, and off the western coast of Denmark. Each project is expected differ in wind park size, interconnections, and technology placed on the island. The first estimates for connections and technologies have been presented by project stakeholders and the Danish government [10]. With this in mind, we analyse the trade-off between interconnecting power lines and electrolysis on the energy island. We add the North Sea energy islands as done by Tosatto et al. [17] and the Bornholm Energy Island in accordance with the latest project proposal [10]. Table 1 lists the projected wind park capacities at the three energy islands, the countries they can connect to, and the abbreviation we use for them (NSEI1, NSEI2, BHEI). We locate the islands following the first feasibility studies by COWI [10] and the North Sea Wind Power Hub Consortium. The Danish Energy Agency designated specific areas[3] in Danish waters for the projects and we use the centre of each area as our location for the hub. We run the model for the years 2030, 2035, and 2040 allowing for investments once in each five-yearly step.

4.1. Data

The model needs technical data on the electricity system, and information on production and investment costs. This section describes the data collection and processing for our case study. Section 4.1.1 elaborates on creating a grid representation with generation units for different energy carriers, Section 4.1.2 summarises the scaling for the future system, and Section 4.1.3 gives an overview of the cost data. Because the problem exceeds current computational capabilities, we reduce the time series and describe the assumptions behind our method in Section 4.1.4. The reduced data instance of the COMBI scenario has 5,160,873 variables, 8,018,612 constraints, and 17,384,020 non-zeros. A scenario takes roughly 25 min to build and about one day to solve on a high-performance computing cluster (AMD EPYC2 7302@16 Cores, 120 GB RAM).

4.1.1. Data set

The first step in our data compilation is creating a base data set for the year 2030. The grid and locations of thermal power generation units published by Hörsch et al. [37] serve as a basis. This data set includes a 1024-node representation of the European power grid with load and thermal power plant capacities matched to all included nodes for 2020. To this, we add new infrastructure projects from the Ten-Year Network Development Plan (TYNDP) 2020 project list[4] and include the energy islands based on project proposals and with the characteristics shown in Table 1. Fig. 6 in the Appendix shows the resulting grid. Planned offshore wind power projects[5] and their capacities are clustered in 19 groups along the coasts of the North and Baltic Seas. Each cluster can connect to the existing onshore grid. The capacity expansion part of the framework endogenously determines sizes of allowed connections.

Data on wind and PV generation at the nodal level is based on a two-step process. Hörsch et al. [37] provide renewables potentials at the nodal level, but these do not match the installed capacities. Thus, in the first step, we take the potentials as ratios to match the currently installed capacities per bidding zone available from ENTSO-E[6] to the nodes. This way, we maintain the ratio of geographical distribution based on potentials and ensure the correct sum of capacities on a

[3] See [29]: ens.dk/en/our-responsibilities/wind-power/energy-islands.

[4] See TYNDP 2020 Project List: tyndp2020-project-platform.azurewebsites.net.

[5] 4C Offshore—Global Offshore Map (2022): map.4coffshore.com.

[6] See ENTSO-E (2022): transparency.entsoe.eu.

Table 1
Summary of important input data. The upper part describes the parameters used in the model. The lower part lists the relevant characteristics of each energy island.

Parameter	Description	Unit	Value	Source
c^E	Cost for electrolyser expansion	€/MW$_e$	Offshore: 645,000 Onshore: 450,000	Fraunhofer ISE [30], Danish Energy Agency [29] and Babarit et al. [31]
c^O	Cost for electrolyser operation	% of CAPEX	2	
η^H	Electrolyser efficiency	MWh$_{LHV}$/MWh$_e$	0.75	
c^D	Penalty for lost load	€/MWh	3000	Nordpool A/S (2021)
c^L	Cost for line expansion	€/(MW· km)	1950	Lauria et al. [32]
c^S	Cost for storage depletion	€/MWh	0.001	
p^{CO_2}	Carbon price	€/t	80, 120, 160	TYNDP (2020)
q	Discount factor		1.04	
r	Interest rate	%	4	
r^H	Hydrogen sales price	€/MWh$_{LHV}$	108	Glenk and Reichelstein [33]
t	Model years		2030, 2035, 2040	
η^S	Storage efficiency		0.8	Hameer and van Niekerk [34]
v	Transmission reliability margin		0.7	Hörsch et al. [35]
$\alpha/\beta/\gamma_{n,y}$, $b_{n,a}$, $h_{o,a}$, $c^O_{g,y}$, $d_{n,t,y}$, j_y, g_i, s^+_s, f^+_d, f^+_a, $p^+_{g/r/s/z}$, p^-_s,	See Table 7.	Available in our GitHub repository.		
Countries	BE, CZ, DE, DK, FI, NL, NO, PL, SE, UK			
Reference year	2018			
Island	**Model name**	**Wind park size**	**Connections**	
NSWPH	NSEI1	10 GW	NO, DE, DK, NL	North Sea Wind Power Hub [36]
Danish EI	NSEI2	10 GW	BE, DE, DK, NL, UK	COWI [10]
Bornholm	BHEI	3 GW	DE, DK, PL, SE	COWI [10]

bidding zone level, which is the highest detail available. Whenever possible, we use the high-resolution Open Power System Data by Schlecht and Simic [38], in this case for Germany, Denmark, and the UK, to replace the generation assets from [37]. In the second step, these nodal capacities need production time series, which we obtain from renewables.ninja [39,40]. These time series are node- and technology-specific. For wind generation, we consider a Vestas V80 2000 generator with a hub height of 100 m. For PV, we assume a 45° tilt angle, strictly facing south.

Hydropower plant data is based on European Commission and JRC [41]. The hydropower plants are matched to the nearest node in the grid. We distinguish run-of-river, reservoir, and pumped hydro. Run-of-river hydro has zero marginal cost, time series for generation come from EMPIRE[7] [42]. Reservoirs are dispatchable resources with annual production limits based on historical data available on ENTSO-E's Transparency Platform[6]. We use a round-trip efficiency for pumped hydro of 80% [34]. Load data is based on Hörsch et al. [37] with a nodal resolution.

4.1.2. Scaling paths

Demand profiles, renewable generation, and installed thermal generation capacity will change over the model horizon. We scale up the data relative to 2020 based on the Gradual Development scenario in the TYNDP 2020.[8] For each generation technology and year, the future projection from TYNDP 2020 divided by the current bidding zone value from ENTSO-E determines a scaling factor. Demand scaling follows the same principle. This scaling preserves the geographical distribution of load and demand within the bidding zones. When, according to the TYNDP, new types of generation occur in a bidding zone, the projected capacity is distributed equally over all its nodes. In some cases, the offshore wind cluster capacities from the list of planned projects[5] exceed the TYNDP projections. In those cases, we include the offshore wind capacity clusters from the list and reduce capacities at other offshore nodes in the same bidding zone to match the overall TYNDP capacity projections for the zone.

4.1.3. Financial parameters

Prices and costs are the main driving factors in the model. We use fuel prices provided in the PyPSA data set [37] to determine technology-specific generation costs. Table 1 summarises the techno-economic parameters used in the model. Below, we explain the origin of the data and some additional assumptions.

RES are assumed to incur no marginal costs. At the end of 2021, fuel prices reached record highs, but this did not change the merit order of power plant use. Recent price peaks resulting from the Russian invasion of Ukraine have not been incorporated in any scenario in this study.

In our model, we assume that capital investments are financed by annuity loans over the lifetime of the assets. The interest rate is fixed at 4%. The model calculates every fifth year from 2030 to 2045, and payments are discounted to the reference year 2030. The connection cables are planned as DC connections. This is done for most big offshore wind parks in the North Sea, with the advantage of coupling non-synchronous countries, for example, Sweden with Germany or Poland. The integration of a DC cable requires converter stations on both sides. We use costs of €1950/(MW km) for our connections [32]. Discharging storage induces a small cost of €0.001/MW to prevent simultaneous charging and discharging by the model.

We use alkaline electrolysers, and differentiate between onshore and offshore installation. New onshore electrolysers have capital costs of €450,000/MW$_e$, and 5% of capital costs occur as annual operational expenditure [29]. New offshore electrolysers are more expensive because of transport, marine conditioning, pipeline construction, and additional operating costs and sum to €645,000/MW$_e$. The efficiency of offshore and onshore technology is set to 75% and the lifetime is estimated to be 30 years [29]. In Appendix B, we provide a detailed overview of the cost parameters for the electrolysis-related investments including a summary of our literature survey.

We keep the unit costs for electrolyser investment fixed at the 2030 values. The model's hydrogen investment results depend heavily on the imposed price development paths and power flow changes in the power system. In the objective function, hydrogen sales are an income to incentivise investment in electrolysers. Price predictions for carbon emission-free hydrogen, also referred to as *green hydrogen*,[9] cover a

[7] openEMPIRE is available on GitHub: github.com/ntnuiotenergy/OpenEMPIRE.

[8] Ten Year Network Development Plan 2020, European Network of Transmission System Operators for Electricity (2020).

[9] Hydrogen is in fact a colourless gas and all hydrogen is a gas with identical chemical characteristics independent of the method of generation.

Table 2
Overview of cases defined for the analysis, including abbreviations.

Case	Name	Investable line capacity	Investable electrolyser capacity
Reference	BAU	Unlimited	None
Offshore H_2	OFFSH	Unlimited	Unlimited offshore only
Offshore & onshore H_2	COMBI	Unlimited	Unlimited
Stakeholder	STAKE	≤10 GW for both NSEI1-2, ≤3 GW for BHEI	Unlimited

wide range (refer to Table 8 in Appendix B). In our analysis we use a hydrogen price of €3.23/kg (equivalent to €108/MWh_{LHV}) as in [33] and use the lower heating value of 33.33 kWh/kg.

4.1.4. Time series reduction

Capacity expansion models tend to become complex as more detail is added. To reduce complexity, one can apply time series reduction methods to determine representative periods [43]. The choice of reduction technique influences the input data and thereby the outcomes [27,28,44,45]. Especially when considering storage usage in high-RES scenarios, time-series reduction methods must preserve fluctuations in generation, both long- and short-term, to obtain capacity expansions still reflecting the optimal values with regard to the original full time series. Göke and Kendziorski [27] analyse different reduction methods for their adequacy for a capacity expansion model. They describe that grouped periods require additional variables in the optimisation problem, hence chronological-sequence algorithms have speed advantages over grouped-period algorithms. Therefore and due to the small deviations in the comparison above, we use the method by Poncelet et al. [28], which bases the time series selection on an optimisation problem preceding the actual framework problem. The algorithm compares the approximated and original duration curves and minimises the difference in equal-sized sections called bins. Both curves' load spans are segmented into a finite number of intervals, and the summed deviations are minimised in a mixed-integer problem for all RES curves considered.

We shorten the year to 21 representative days by using 20 bins and chronological sequencing with re-scaling without changing the weighting and length of the chosen periods. The time series reduction method of Poncelet et al. [28] is computationally costly, especially on our data set, with simultaneous optimisation of 544 nodes with RES infeed. For capacity expansion models of energy systems, the objective values of the model run with shortened time series deviate only slightly from the full time series objectives, according to Zatti et al. [46]. We can confirm this with the results of running over longer and reduced periods (not reported in this paper).

4.2. Case setup

We set up four different cases and compare their results. Table 2 provides an overview of the cases. The first is a reference case, *BAU*, in which all wind farms are placed in accordance with current proposals (see Table 1) and we only determine cable connections to the surrounding countries. To analyse the trade-offs between electrolysers and cable expansions, the three further cases add options for electrolysis (as opposed to cable investment only). In the second case, *OFFSH*, we allow investment in offshore electrolysers on the energy islands. In case three, *COMBI*, we allow additional investment in onshore electrolysis at the landing points—the points of connection between the onshore and offshore networks. In case four, *STAKE*, we limit the cable expansions to shore for each island to the maximum capacity planned by the stakeholders.

5. Results and discussion

In this section, we describe the results of the case study, analysing energy hubs in the North and Baltic Seas. The first part describes the overall results and identifies the main findings. Section 5.2 focuses on offshore electrolysers and why they are being built. Section 5.3 presents the sensitivity studies to test the impact of the assumptions made about carbon and hydrogen prices and the electricity grid.

5.1. Main findings

The main results for the four cases are described in Table 2. We start by looking at overall system costs and then discuss cable expansion and electrolyser investments for each case separately.

The combined investment and dispatch costs scaled up to annual costs differ among the cases. *COMBI* is the cheapest at €116 billion. *STAKE* has about the same cost. The most expensive is *BAU* at €140 billion (20% higher than COMBI). *OFFSH* is the second most expensive, with costs about 1.7% higher than *COMBI*. This suggests that sales from hydrogen production can visibly lower system costs, despite the significant investment expenditures that must be paid off. Offshore cable capacity is built in all cases, and whenever it is allowed, significant electrolyser capacities are placed either onshore or offshore to produce and sell hydrogen. The positioning of electrolysis on the energy islands influences the cable allocation. Table 3 summarises the results of all four cases and the relative changes between successive cases.[10]

5.1.1. Reference case: BAU

In *BAU*, an aggregated 17.6 GW of cable connections are built in 2030 to connect the energy islands to shore (Table 4). All countries are connected from the first period. Over the years, aggregate capacity increases very modestly. In addition to direct cables, a strong offshore grid develops between the wind farm clusters, the islands, and the shores; see Fig. 3(a).

5.1.2. Offshore electrolysis only: OFFSH

Allowing electrolysis on the energy islands only results in lower direct power cable capacities to shore. In Table 4, we see capacities to connect the islands that are significantly lower than BAU, see Table 4. The aggregate offshore electrolyser capacity increases evenly over the periods as renewable energy capacity is expanded. Most of the electrolyser capacity is built in the North Sea, specifically at NSEI1 (our reference to the North Sea Wind Power Hub), which is well-positioned between many countries and closer to their shores than NSEI2. Fig. 4(a) maps the electrolyser capacities in 2040 for the different cases to the locations. Comparing Figs. 3(a) and 3(b), we see that NSEI1 not only develops more electrolyser capacity but is also better connected to shore than NSEI2. Although all direct connections from the islands to shore aggregate to no more than 10 GW, Fig. 3(b) also shows that connections from the offshore wind clusters to the islands are

[10] Since cases two and three step-wise allow more investment compared to case one, and the fourth case provides a reality check for the third, we believe that these comparisons provide the most insight.

Table 3
Case study results: % changes relative to the case with more restrictions in the lines above.

	Electrolyser capacity [GW]			Hydrogen production [TWh]			Curtailment [TWh]			Thermal generation [TWh]		
	2030	2035	2040	2030	2035	2040	2030	2035	2040	2030	2035	2040
BAU												
Offshore	–	–	–	–	–	–	6.9	6.7	7.2	–	–	–
Onshore	–	–	–	–	–	–	67.3	75.4	87.5	437.6	430.8	473.6
OFFSH												
Offshore	44.7	50.1	56.0	209.6	216.5	244.1	3.2	2.2	2.0	–	–	–
rel. change to BAU	–	–	–	–	–	–	−54.0%	−66.8%	−72.1%	–	–	–
Onshore	–	–	–	–	–	–	8.9	14.4	21.8	471.7	448.1	491.8
rel. change to BAU	–	–	–	–	–	–	−86.8%	−80.8%	−75.1%	7.8%	4.0%	3.8%
COMBI												
Offshore	7.5	17.5	17.5	89.6	84.7	86.3	2.3	2.0	1.6	–	–	–
rel. change to OFFSH	−60.9%	−65.1%	−68.8%	−57.3%	−60.9%	−64.6%	−27.9%	−9.6%	−21.9%	–	–	–
Onshore	33.2	38.7	46.1	130.3	143.2	171.3	7.9	13.1	19.5	474.7	451.7	495.7
rel. change to OFFSH	–	–	–	–	–	–	−10.5%	−9.5%	−10.5%	0.6%	0.8%	0.8%
STAKE												
Offshore	17.5	17.5	17.5	91.3	83.5	88.3	2.5	2.2	1.7	–	–	–
rel. change to COMBI	0.0%	0.0%	0.0%	2.0%	−1.4%	2.3%	10.2%	7.8%	7.6%	–	–	–
Onshore	33.2	38.7	46.2	128.5	144.3	169.4	7.8	13.0	19.4	474.8	451.7	495.6
rel. change to COMBI	−0.2%	−0.1%	0.1%	−1.4%	0.8%	−1.1%	−2.1%	−0.8%	−0.6%	0.0%	0.0%	0.0%

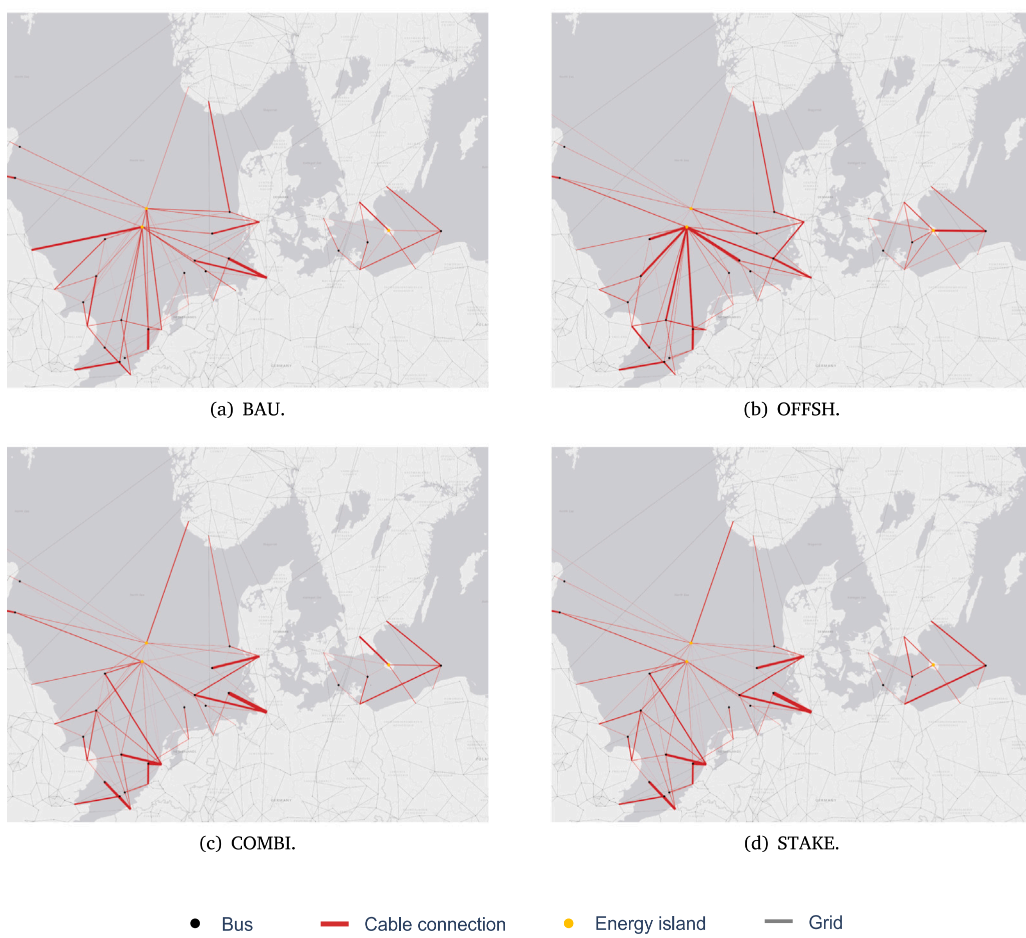


Fig. 3. Comparison of cable connection capacity between the energy islands and shore in the different cases in 2040. The thickness of the red lines indicates the capacity of the constructed connection.

important. Allowing offshore electrolysis lowers the need for power cable capacity of the energy islands and the wind clusters to shore but leads to higher offshore cable connections between wind clusters and the energy islands, see Table 4. Specifically, the wind farms off the coast of the Netherlands are connected by large cables to the energy islands. Hydrogen production from the offshore electrolysers adds up to 244 TWh in 2040, which is in line with the European industrial demand predicted by Agora Energiewende and AFRY Management Consulting [47]. In 2030, about half of the hydrogen production originates in avoided RES curtailment.

Table 4
Capacity of cable connections at sea for each case and year.

	Energy island to shore [GW]			Wind cluster to island [GW]			Wind cluster to shore [GW]		
	2030	2035	2040	2030	2035	2040	2030	2035	2040
BAU	17.7	18.2	18.5	19.9	21.1	21.6	71.8	73.6	74.8
OFFSH	5.7	7.3	9.9	42.7	48.1	54.7	71.0	73.9	75.7
COMBI	10.4	11.0	12.0	10.9	13.2	15.2	99.6	103.1	106.3
STAKE	7.8	8.3	9.1	10.8	13.1	15.5	102.2	105.8	109.2

5.1.3. Combined onshore and offshore electrolysis: COMBI

The option to invest in onshore electrolysis is represented in our *COMBI* case. In comparison to *OFFSH*, the aggregated capacity of cables directly connecting energy islands to shores is slightly higher; see Table 4. However, they are much below *BAU* (about 35% lower in 2030, and comparably lower in 2035 and 2040). In COMBI, a meshed offshore grid or strong connections between the energy islands and the offshore wind clusters are not a significant part of the optimal system solution. In Fig. 3(c), we see that the offshore wind clusters are mostly connected to shore, meaning that landing points receive larger cables compared to *OFFSH*. Electrolysers in this case are mainly built onshore. Offshore electrolysers have 68.8% lower aggregate capacity, split unevenly among the three islands and all located in the North Sea. In 2040, aggregate electrolysis is greater than aggregate offshore capacity in *OFFSH*, resulting in higher hydrogen production in *COMBI* than in *OFFSH*. Onshore electrolysers are built at all landing points; see Fig. 4(b). The locations and development of electrolysers over the years follow RES expansion projects in the countries. Curtailment and thermal generation are at similar levels to *OFFSH*.

5.1.4. Restricting cable connections: STAKE

In our last case, we consider current plans for cable capacities to connect the islands. In *STAKE*, cable expansion capacity is restricted to currently planned capacities: 1 GW of cable per GW of wind farm commissioned (c.f., [10]). This restriction does not change the results and is in line with the *COMBI* case with respect to both electrolyser and cable capacity; see Figs. 8 and 9 in the Appendix.

5.1.5. Comparison of cases

BAU leads to the highest need for cable investment in direct shore-island connections. Only allowing electrolyser capacity offshore requires strong connections between offshore wind farms and the energy island. Allowing the installation of electrolysers both onshore and offshore, as in *COMBI* and *STAKE*, we observe moderate direct cable connections from shore to islands. These cases allow for onshore electrolysis investments, which are assumed to be cheaper than building the assets offshore. The option of cheaper onshore electrolysis does not eliminate offshore electrolysis but lowers the capacity of energy-island-to-shore cable connections. However, by 2040, a strong offshore grid develops with capacities of 133 GW through cables in the sea. *BAU* leads to the highest curtailment and the lowest thermal technology use in 2040 because there is no electricity usage by electrolysers. We summarise our main findings as follows:

- Restricting electrolysis to offshore results in higher cable capacities connecting the energy islands to offshore wind farms.
- Limiting cable expansions according to project plans does not show much effect, and the results for *COMBI* and *STAKE* are very similar.
- Allowing investment in electrolysers both offshore and onshore lowers the curtailment of RES significantly.
- Electrolysis on the energy island of Bornholm (BHEI) is relevant only in the absence of onshore electrolysis or cable capacity expansion limitations.

Table 5
Capacity factors of electrolysers ([%], weighted average).

	Offshore			Onshore		
	2030	2035	2040	2030	2035	2040
BAU	–	–	–	–	–	–
OFFSH	52.4	53.6	49.8	–	–	–
COMBI	58.5	55.3	56.4	44.7	42.2	42.4
STAKE	59.7	54.5	57.7	44.2	42.6	41.9

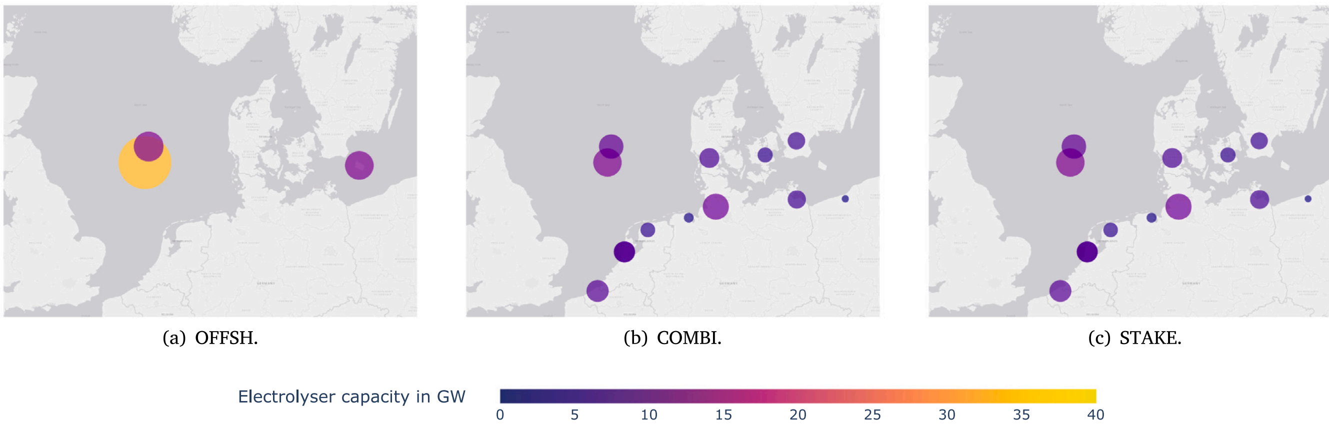
In addition to capacity expansions, the model shows trade patterns between the market zones. Interestingly, the energy islands in the North Sea both become net importers in all cases in the first two periods (but not in the third). The more the system changes towards a RES-based system the more electricity is used for direct consumption. In all cases, the same countries are net importers or net exporters: Germany, Poland, the UK, and Sweden are net exporters, and Belgium, the Netherlands, Denmark, the Czech Republic, Finland, and Norway are net importers. The wind park clusters built off the coasts of the respective countries require large investments in electricity infrastructure, and in the cases of Germany and the UK, the planned RES capacities exceed what onshore grids can integrate (see Fig. 7 in the Appendix). Therefore, the wind parks are integrated with other markets through combined grid solutions, which connect two countries via a wind farm or other system assets, often also called hybrid assets (cf. [48]).

5.2. The role of electrolysers on energy islands

In this study, we analyse and discuss the trade-off between electricity and hydrogen infrastructure to integrate energy islands into the existing energy system. To identify possible trade-offs, we zoom in on the specific drivers of hydrogen production and on its location in different cases. In general, electrolysis can cut down curtailment due to grid congestion and increase the use of available renewable energy technology.

As described above, when we only allow electrolyser capacity investment offshore, on the energy islands, we see (1) higher system costs, (2) higher cable capacities in the seas in Northern Europe, and (3) higher curtailment than when we allow both offshore and onshore electrolysis. However, from Table 11 in Appendix C we also see that in the *OFFSH* and *COMBI* cases generation from nuclear and biomass[11] rises as the aggregated electrolyser capacity increases. This suggests that existing nuclear capacities can generate at costs that are competitive for electrolysis. The capacity factor is an important metric for the profitability potential of investments in and operation of electrolysers, independently of their placement. Thermal generation may be cheap enough to use for hydrogen production, such that the capacity factor increases. Cable connections between offshore wind clusters and energy islands are very large in the pure *OFFSH* case. Here, the additional cables also contribute to fuelling the electrolyser on the islands from onshore power generation, making offshore electrolysis more profitable. The offshore electrolysers operate at an average capacity factor of 52.4% in 2030 and 49.8% in 2040; see Table 5. For the

[11] The model does not consider alternative use of biomass, e.g., direct gasification but only assumes direct power generation.



(a) OFFSH. (b) COMBI. (c) STAKE.

Fig. 4. Comparison of electrolyser locations and capacities in the different cases in 2040.

COMBI case with smaller cable connections, the offshore electrolysis capacity factors are slightly higher. Onshore electrolysers, however, are operated at capacities of just above 40% on average. The lower investment expenditures allow them to be profitable already at lower usage rates. In *STAKE*, electrolysis capacity and capacity factors both onshore and offshore are similar to those of *COMBI*. Our results are aligned with other sources indicating that electrolysers need a capacity factor of at least 35% to operate economically [49].

A closer look at our results reveals a system of coordinated joint hydrogen and electricity production. So far in Europe, RES capacities have been mostly installed onshore (PV and wind), and at present offshore wind is typically connected radially to shore, not going through an energy island. Radially connecting offshore wind farms leads to higher RES availability and excess production onshore than if conversion assets are also placed offshore. Endogenising the decision about the placement of electrolysers results in a combination of large onshore capacities and about 10 GW of aggregated electrolysis capacity offshore. This finding differs from those of, for example, Gea Bermúdez et al. [20] and Singlitico et al. [19], who argue that offshore electrolysis will not play a role. An important contribution of our work is that our model includes a detailed onshore grid representation. In contrast, Gea Bermúdez et al. [20] in their model consider a zonal approach, neglecting inner-zonal congestion and foresee large electricity import from southern Europe to reach electrolysers onshore along the coasts.

When the model allows it, most electrolysis capacity is installed onshore despite the lower capacity factors. At the same time, thermal generation is higher showing that it is economical to produce hydrogen from nuclear power, at least given its modest short-term marginal costs. In the model, the onshore grid capacities are fixed for the entire horizon, only including projects through the early 2030s that are already planned today. This possibly restricts access to RES from other geographic locations, having a two-fold impact: (1) the only technologies for stabilising the capacity factors are thermal power plants because they are effectively located with respect to current grid topology, and (2) curtailment cannot be lowered further due to onshore congestion. To address this limitation, we include a sensitivity analysis to assess the impact of onshore grid expansions on curtailment, thermal power plant use, and combined system costs.

5.3. Sensitivity analysis

Here we perform a two-fold sensitivity analysis. The first part considers hydrogen and carbon prices. The second considers a fundamental basis of the model, the power network, and extends the onshore grid in an attempt to remove congestion. For the sensitivity analysis, we work with the setup and assumptions of the *COMBI* case of the main analysis, which had the lowest overall costs.

5.3.1. Price variations

In this first sensitivity analysis, we change the hydrogen price and the carbon price as presented in Table 6. First, we vary the hydrogen price by lowering and raising it by 25%, from the original €108 per MWh to €81 and €135, respectively, while keeping the CO_2 prices at the level of our original case study: €80, €120, and €160 respectively in years 2030, 2035, and 2040. We compare the results of our sensitivity analysis to *COMBI* of the main analysis and list the key values in Table 10 in Appendix.

A 25% lower hydrogen price results in 13% less aggregated electrolyser capacity with onshore electrolysis seeing the largest reduction. In addition, there is a lower direct cable capacity to shore when hydrogen prices are lower, as it is less interesting to bring power generated onshore to the islands. We still see 15 GW of offshore electrolysis, which implies that a larger part of the hydrogen is produced on the energy islands. In addition, thermal power production is lower in all years; see Fig. 5. This suggests that lower hydrogen prices decrease the value of hydrogen production and more renewable electricity is used for direct consumption resulting in more cable connections from the offshore wind clusters to shore and lower shares of fossil fuels and nuclear in the electricity mix. In the scenario with a 25% higher hydrogen price, we see the opposite. Higher aggregate electrolysis capacity is invested, and a relatively larger share is built onshore. Cable connections between island and shore and between wind clusters and shore are larger than in *COMBI* of our main analysis, which suggests that larger electricity cables can be refinanced by higher sale prices for hydrogen. Thermal power production is at a similar level in the main analysis and for low and high hydrogen prices, except for the high hydrogen price in the first period. Similarly to the main analysis, in both cases, thermal technology contributes to hydrogen production. In the first period with a high price, it is attractive to use lignite for hydrogen production due to a moderate CO_2 price. When changing the hydrogen price, we observe that the lower price reduces electrolyser capacities and leads to less hydrogen production, see Fig. 5. The additional revenue from selling hydrogen makes mainly a combination of cable connections and onshore electrolysis economical. This lowers curtailment and results in more hydrogen production.

In the second sensitivity analysis, we change the CO_2 prices to €130 in 2030, €250 in 2035, and €480 in 2040 for each ton emitted. These values correspond to values in the openEntrance[12] 1.5 °C scenario *Techno Friendly* [50]. The higher carbon price not only increases system costs but leads to higher aggregate cable capacity between energy island and shore and between energy island and wind cluster from the first period onward (20% more than in the main analysis from 2030

[12] openEntrance is a research project mapping the energy system transformation to reach climate goals. See: openentrance.eu/.

Table 6
Price parameter changes of the sensitivity analysis.

Prices in [€]	CO_2 price			H_2 price		
Scenario	2030	2035	2040	2030	2035	2040
Initial configuration	80	120	160	108	108	108
Lower H_2 price	80	120	160	81	81	81
Higher H_2 price	80	120	160	135	135	135
Higher CO_2 price	130	250	480	108	108	108
Grid extension	80	120	160	108	108	108

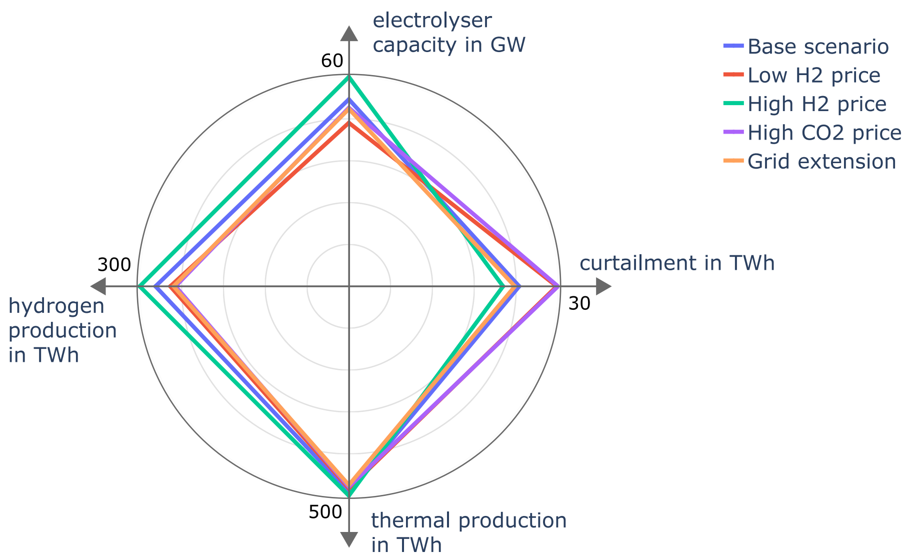


Fig. 5. Comparison of thermal power plant usage and electrolyser capacity in the different parts of the sensitivity analysis.

onward). With increasingly higher CO_2 prices, it would be valuable to invest earlier to increase the use of RES in the system and avoid carbon emissions as much as possible. Electrolysis becomes slightly less attractive and is 3% lower each year compared to the main analysis. Fig. 5 shows that in comparison to the main analysis, an increased carbon price will lead to lower use of thermal generation but a similar aggregate electrolysis capacity. This scenario would very likely change further if it were combined with onshore grid expansion.

5.3.2. *Onshore network capacities*

From our main analysis, we can identify onshore power lines and interconnectors that are often congested. Fig. 7 in the Appendix shows the share of hours the depicted lines exceed 99% of their available capacity and we, therefore, consider them congested. For this sensitivity analysis, we assume a line to be limiting and prone to extension if the share of congested hours over the entire time horizon exceeds 70%. To relieve the bottlenecks, we add 20% multiplied by the share of congested hours to the existing capacity of each expanded line, consequently between 14% and 20%. We keep all other values and prices as in the original analysis. Here we present new results for the *COMBI* case in 2040 with an extended onshore network. Exogenously relieving the congestion from the grid this way lowers the combined investment and dispatch costs (5% below the main analysis) and leads to the lowest curtailment of all the cases. The reinforced grid leads to a similar integration of offshore resources by cable but a 5% lower electrolyser capacity; see Table 10. Thermal power production is also at its lowest level because the larger transmission capacities bring larger shares of RES to consumption nodes and reduce curtailment. In summary, onshore grid expansion leads to higher usage of RES and lower system costs (however not considering the cost of the exogenous grid extension) and has comparable system characteristics to *COMBI*.

5.4. *Discussion of model assumptions*

All the generation capacity in 2030 and the onshore grid are based on exogenous assumptions, as are the scaling paths to 2040. Not allowing endogenous capacity extension in the existing and projected power generation fleets restricts the construction of a theoretically optimal system design and influences the sizing of cables and electrolysers. For investment expenditures, we assume linearity, neglecting economies of scale and scope and learning rates. Furthermore, we have tested the model results on their sensitivities to changes in electrolyser OPEX. This showed that a 3 pp increase in OPEX leads to a 5% reduction in electrolysis capacity, see Table 10 with case low OPEX. For the locations, we assume that these are chosen by the reference projects, which may be a bias and could over- or underestimate the distance to onshore grid connection points. Offshore hydrogen production requires transportation by vessels or pipeline connections, which we include with a fixed cost markup per unit of capacity only. Together with the assumption of the islands' locations, this could slightly distort the costs and trade-off between hydrogen and electricity infrastructure. Hydrogen offtake is modelled via a fixed price rather than endogenised demand. Yet, given the amount of hydrogen produced in the model compared to hydrogen demand projections for Europe, we view this assumption as uncritical. Furthermore, we have specifically addressed the sensitivity of hydrogen prices.

Last, we assume there will not be any integration with other sectors, such as heat—that is, no consideration of the use of excess heat from electrolysis. However, this is arguably equally relevant to the efficiency of onshore and offshore electrolysis. In the onshore case, it could increase the process efficiency by utilising heat to satisfy local heat demand. Offshore heat can be used for desalination processes to produce distilled water for electrolysis. The reduced time horizon and the reduced time series used for this model may affect the representative accuracy of demand and production patterns. Diving deep into the results and examining each capacity expansion, we also observe that there are some small cables (smaller than 500 MW) built between different offshore nodes. We assume that such small capacities would not be built in reality. For the combined case of onshore and offshore infrastructure, this could reduce the number of countries connecting directly to energy islands.

6. Conclusion

In this paper, we study the trade-off between investments in offshore electrolysers and in cable connections between energy islands and both offshore wind farms and shore, and more generally the trade-off between electricity transmission and hydrogen production infrastructures offshore. For the analysis, we have developed an integrated capacity expansion and electricity dispatch model with power grid representation, which allows the energy islands to be connected by electricity cables to shore or to host hydrogen production.

In our main analysis, which adds hydrogen infrastructure investment options step by step to a system of electricity infrastructure only, we find that onshore electrolysis plays a larger role than its offshore counterpart. Offshore electrolysers, however, are especially relevant for using the electricity produced on energy islands, reducing curtailment, and keeping cable connections at a moderate level. All countries developing wind farms off their coasts build electrolysers onshore with capacities in the range of 5 to 10 GW. Based on our sensitivity analysis, we argue that this is also driven by congestion in the onshore grid. Exogenously reinforcing the network by increasing onshore grid capacities to remove congestion shows higher usage of RES onshore to meet electricity demand rather than more conversion to hydrogen. Driven by low short-run marginal costs, nuclear and biomass also serve as fuel for hydrogen production and increase capacity factors, but this can be counteracted by higher CO_2 prices. Investment in electrolysis capacity is most sensitive to future hydrogen prices and the costs of technology. On the trade-off between hydrogen and electricity infrastructure for energy islands, we conclude that electricity from offshore wind is more valuable than hydrogen for reducing carbon emissions from generation. Onshore electrolysis can benefit from efficiency gains through sector coupling and heat usage. In contrast, a lack of public acceptance of wind farms and electrolysis plants could drive up costs and favour offshore locations [51]. Offshore, on the other hand, excess heat could be used for seawater desalination [52]. Onshore grid developments influence offshore development significantly, and the siting of electrolysers is sensitive to congestion in the grid. First-mover expenses, however, will be higher, and the results on sizing presented in this paper must be considered with caution since, in reality, they will rather be political decisions that are not fully market-driven.

The presented analysis and results depend on assumptions and model limitations. We do not consider all the technical features and constraints of the generation technologies (e.g., unit commitment and ramping), we use only one average power curve for the wind power installations without distinguishing by the age of the installation over time, and we disregard market sequences that might have an impact on trading activities, prices, and the availability of electricity in the system. The parameters for the cost of electricity production, hydrogen infrastructure, and hydrogen markets are subject to large uncertainties, as is the production from renewable energy. This analysis could benefit from a stochastic approach to balance and hedge decisions considering uncertainty in production, prices, and technology cost development. Furthermore, the geographical scope of the model may be extended to include countries in the second row behind the seas, for example, France and also the Baltic countries. In the current results, offshore and onshore electrolysers are profitable and worth investing in at comparatively low capacity factors. Another source of distortion may be neglecting any costs for the energy island itself, for example, general costs for land use, or network charges and taxes. Further, we ignore the fact that cables come in predetermined sizes per unit, and considering this, e.g., using binary variables to reflect fixed costs and bundle sizes, may change the outcome. In addition, power prices in the current markets in Europe are not based on nodal pricing, which we use in this model. Generally, a zonal market setup will result in different market prices and may change the attractiveness of investing in electrolysers due to higher power purchasing prices. Being aware of the limitations in our approach, we do believe that the insights are generalisable beyond the limits of the specific case studies that we have analysed. Offshore power transmission and hydrogen production infrastructure complement each other in bringing energy to shore, mitigating RES intermittency, and reducing curtailment. Both will have a significant role in the integration of offshore wind energy into the northwestern European energy system.

CRediT authorship contribution statement

Alexandra Lüth: Conceptualization, Data curation, Visualization, Writing – original draft, Writing – review & editing. **Paul E. Seifert:** Conceptualization, Data curation, Software, Visualization, Writing – original draft, Writing – review & editing. **Ruud Egging-Bratseth:** Conceptualization, Supervision, Writing – review & editing. **Jens Weibezahn:** Conceptualization, Supervision, Visualization, Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Open data has been used. The code is made openly available at https://github.com/pauleseifert/NodalMOD/releases/tag/1.0.

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Appendix A. Framework description

A.1. Nomenclature

Table 7 presents the nomenclature used in the paper. Sets are expressed in script, parameters in lowercase, and variables in uppercase italic letters.

Table 7
Designated sets, parameters, and variables of the mathematical framework.

Sets	
$\mathcal{N}$	Set of nodes: n, m
$\mathcal{G}$	Set of thermal power plants: g
$\mathcal{W}$	Set of reservoirs: w
$\mathcal{R}$	Set of RES: r
$\mathcal{S}$	Set of storages: s
$\mathcal{E}$	Set of electrolyser: e
$\mathcal{A}$	Set of AC transmission lines: $a \in (n, m)$
$\mathcal{D}$	Set of DC transmission lines $d \in (n, m)$
$\mathcal{L}$	Subset of $\mathcal{D}$, lines to the EI $l \in (n, m)$
$\mathcal{T}$	Set of time slices: t
$\mathcal{Y}$	Set of years: y
$\mathcal{O}$	Set of $\mathcal{A} - \mathcal{N} + 1$ cycles: o
$\mathcal{Z}$	Set of bidding zones: z
Parameters	
$\alpha/\beta/\gamma_{n,y}$	Scaling factor for capacity development of thermal generation/RES/demand
δ	Scaling factor for time series reduction
$\eta^{E/S}$	Efficiency of electrolyser/storage units
$b_{n,a}$	Incidence matrix entry of node n at line a
$h_{o,a}$	Cycle incidence matrix entry of cycle o and line a
c^D	Penalty for loss of load
$c^M_{g,y}$	Marginal cost of power plant in €/MWh$_{el}$
c^O	Operational and maintenance cost for electrolyser in % of capital expenses
c^S	Costs for storage depletion
c^E	Cost of electrolyser in €/MW
c^L	Cost for transmission line in €/(MW km)
$d_{n,t,y}$	Demand at node n of year y
j_y	Discount factor of year y
$k^{E/L}$	Annuity factor electrolyser/line
g_i	Length of the electricity line i in km
s^+_s	Capacity of storage s in MWh$_{el}$
f^+_d	DC line capacity in MW$_{el}$
f^+_a	AC line capacity in MW$_{el}$
$p^+_{g/r/s}$	Maximum power generation of thermal generation/RES/storage in MW$_{el}$
p^+_z	Maximum energy production from hydro reservoir in MWh$_{el}$
p^-_s	Maximum power consumption of storage in MW$_{el}$
q	Discount factor (1 + interest rate)
r^E	Revenue from selling hydrogen in €/MWh
v	TRM between 0 and 1
x_a	Reactance of AC line a in Ω
Decision variables	
$I^E_{e,y}$	Installed capacity of the electrolyser e in year y in MW$_{el}$
$I^L_{l,y}$	Installed capacity of the electricity connection line l to the EI in year y in MW$_{el}$
$F^A_{a,t,y}$	AC line flow of line a in MW$_{el}$
$F^L_{l,t,y}$	EI connection line flow of line l in MW$_{el}$
$F^D_{d,t,y}$	DC line flow of line d in MW$_{el}$
$S^L_{s,t,y}$	Storage level of storage unit in MWh$_{el}$
$P^C_{g,t,y}$	Generated thermal power in MW$_{el}$
$P^{D-}_{n,t,y}$	Demand loss of load at node n in MW$_{el}$
$P^R_{r,t,y}$	Generated RES power in MW$_{el}$
$P^W_{w,t,y}$	Generated power from reservoir in MW$_{el}$
$P^{R-}_{n,t,y}$	RES curtailment at node n in MW$_{el}$
$P^E_{e,t,y}$	Electrical power to the electrolyser in MW$_{el}$
$S^D_{s,t,y}$	Generated power from storage discharge in MW$_{el}$
$S^C_{s,t,y}$	Power withdrawal from storage charge in MW$_{el}$

A.2. Objective

The objective function Eq. (1) minimises the cost for dispatch and capacity extensions. In the dispatch we include marginal costs c^M for dispatching thermal power plants P^C, cost c^D for curtailing load P^{D-}, and a discharge penalty c^S for storage P^S. In addition, we subtract income r^E from producing hydrogen P^E. RES do not incur marginal costs. Investments in electrolysers I^E and connecting power lines I^L are allowed at specific costs $c^{E/L}$ adjusted by an annuity factor $k^{E/L}$ (Eq. (2)). For electrolysers we include annual operation and maintenance costs c^O.

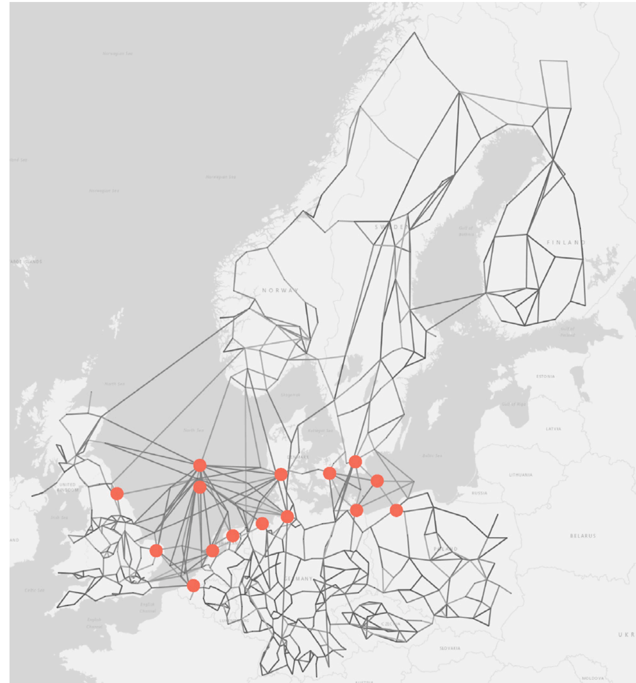

Fig. 6. Representation of the grid including all possible connections between energy island and shore.

$$\min \sum_y \Bigg[\delta \cdot \Bigg(\sum_t \sum_g c^M_{g,y} \cdot P^C_{g,t,y} + c^D \cdot \sum_t \sum_n P^{D-}_{n,t,y} + c^S \cdot \sum_t \sum_s P^S_{s,t,y} - \sum_t \sum_e r^E \cdot P^E_{e,t,y} \cdot \eta^E \Bigg) + c^E \cdot \sum_e (k^E + c^O) \cdot I^E_{e,y} + k^L \cdot c^L \cdot \sum_l g_l \cdot I^L_{l,y} \Bigg] \cdot j_y \tag{1}$$

$$k^{E/L} = \frac{q}{1 - \left(\frac{1}{1+q}\right)^{\text{Lifetime}}} \tag{2}$$

The framework runs for a reduced time series. δ scales the representative days to the full set of 8760 time steps and is consequently approximated to be $\frac{8760}{t}$ rounded to ten decimals. For the horizon of multiple (five-year) periods y, we use a discount factor j_y (Eq. (3)) to discount all costs to the reference period.

$$j_y = \frac{1}{(1+q)^{5 \cdot y}} \tag{3}$$

A.3. Energy balance

We limit the framework by a set of constraints. Eq. (4) introduces the supply–demand balance for each node: the sum of the power generation by thermal power plants P^C, RES P^R, reservoirs P^W, storage flows $S^{C/D}$, electrolyser consumption P^E, and load d must always equal the nodal power injections F by the connected AC and DC transmission lines. A variable for loss of load P^{D-} allows load shedding.

$$\sum_{g \in \Delta^G_n} P^C_{g,t,y} + \sum_{r \in \Delta^R_n} P^R_{r,t,y} + \sum_{w \in \Delta^W_z} P^W_{w,t,y} + \sum_{s \in \Delta^S_n} S^D_{s,t,y} - \sum_{s \in \Delta^S_n} S^C_{s,t,y} - \sum_{e \in \Delta^E_n} P^E_{e,t,y} + \sum_m F^D_{m,n,t,y} - \sum_m F^D_{n,m,t,y} + \sum_a b_{n,a} \cdot F^A_{a,t,y} = \gamma_y \cdot d_{n,t,y} - P^{D-}_{n,t,y} \quad n \in N, t \in T, y \in Y \tag{4}$$

A.4. Investments

The DC power connections to the energy islands are endogenously decided by the framework. Flow F^{L} is limited by the installed capacities (Eqs. (5) and (6)). Line capacities can only be extended and Eq. (7) ensures that no decommissioning should take place. On all lines, there is a transmission reliability margin v deducted from full capacity.

$$F^{\mathrm{L}}_{l,t,y} \le I^{\mathrm{L}}_{l,y} \cdot (1-\mathrm{v}) \qquad l \in \mathcal{L}, t \in T, y \in \mathcal{Y} \tag{5}$$

$$F^{\mathrm{L}}_{l,t,y} \ge -\left[I^{\mathrm{L}}_{l,y} \cdot (1-\mathrm{v})\right] \quad l \in \mathcal{L}, t \in T, y \in \mathcal{Y} \tag{6}$$

$$0 \le I^{\mathrm{L}}_{l,y-1} \le I^{\mathrm{L}}_{l,y} \qquad l \in \mathcal{L}, y \in \mathcal{Y} \tag{7}$$

Electrolyser capacity can only be expanded in the next period and cannot be decommissioned, Eq. (8).

$$0 \le I^{\mathrm{E}}_{e,y-1} \le I^{\mathrm{E}}_{e,y} \quad e \in \mathcal{E}, y \in \mathcal{Y} \tag{8}$$

A.5. Operational constraints

Thermal power plants P^{C} and RES P^{R} including run-of-river hydropower can only operate below their maximum electricity output or installed capacities p^{+}, respectively. Due to multi-period optimisation, scaling factors α and β adjust the installed capacities, see Eqs. (9) and (10).

$$0 \le P^{\mathrm{C}}_{g,t,y} \le \alpha_y \cdot \mathrm{p}^{+}_{g} \quad g \in \mathcal{G}, t \in \mathcal{T}, y \in \mathcal{Y} \tag{9}$$

$$0 \le P^{\mathrm{R}}_{r,t,y} \le \beta_y \cdot \mathrm{p}^{+}_{r,t} \quad r \in \mathcal{R}, t \in \mathcal{T}, y \in \mathcal{Y} \tag{10}$$

For evaluation purposes the RES curtailment $P^{\mathrm{R}-}$ is defined as the difference between the possible RES generation p^{+} and the actual dispatch P^{R}.

$$0 \le P^{\mathrm{R}-}_{n,t,y} = \beta_y \cdot \mathrm{p}^{+}_{r} - P^{\mathrm{R}}_{r,t,y} \quad r \in \mathcal{R}, t \in \mathcal{T}, y \in \mathcal{Y} \tag{11}$$

Additionally, hydropower reservoirs are limited in their maximum production in the chosen period and bidding zone to ensure a more realistic representation of water availability, Eq. (12).

$$\sum_{t \in \mathcal{T}} \sum_{w \in \Delta^{W}_{z}} P^{\mathrm{W}}_{w,t,y} \le \mathrm{p}^{+}_{z} \qquad \forall\, z \in Z, y \in Y \tag{12}$$

Storage (i.e., batteries and pumped hydropower) usage $S^{\mathrm{C/D}}$ is limited by maximum charge p^{+}_{s} (Eq. (13)) and discharge p^{-}_{s} (Eq. (14)) rates as well as an upper capacity limit s^{+}_{s} (Eq. (15)). Eq. (16) defines the filling level of the storage S^{L} taking into account efficiency losses. Eqs. (17) and (18) fix the starting and ending levels of storage to half its capacity, respectively.

$$0 \le S^{\mathrm{C}}_{s,t,y} \le \mathrm{p}^{+}_{s} \quad s \in \mathcal{S}, t \in \mathcal{T} : t > 1, y \in \mathcal{Y} \tag{13}$$

$$0 \le S^{\mathrm{D}}_{s,t,y} \le \mathrm{p}^{-}_{s} \quad s \in \mathcal{S}, t \in \mathcal{T} : t > 1, y \in \mathcal{Y} \tag{14}$$

$$0 \le S^{\mathrm{L}}_{s,t,y} \le \mathrm{s}^{+}_{s} \quad s \in \mathcal{S}, t \in \mathcal{T} : t > 1, y \in \mathcal{Y} \tag{15}$$

$$S^{\mathrm{L}}_{s,t,y} = S^{\mathrm{L}}_{s,t-1,y} - S^{\mathrm{D}}_{s,t,y} + \eta^{\mathrm{S}} \cdot S^{\mathrm{C}}_{s,t,y} \quad s \in \mathcal{S}, t \in \mathcal{T} : t > 1, y \in \mathcal{Y} \tag{16}$$

$$S^{\mathrm{L}}_{s,t,y} = 0.5 \cdot \mathrm{s}^{+}_{s} - S^{\mathrm{D}}_{s,t,y} + \eta^{\mathrm{S}} \cdot S^{\mathrm{C}}_{s,t,y} \quad s \in \mathcal{S}, t \in \mathcal{T} : t = 1, y \in \mathcal{Y} \tag{17}$$

$$S^{\mathrm{L}}_{s,t,y} = 0.5 \cdot \mathrm{s}^{+}_{s} \quad s \in \mathcal{S}, t \in \mathcal{T} : t = 8760, y \in \mathcal{Y} \tag{18}$$

For the electrolysis capacity built in the framework, there is a maximum power inflow restriction constraint to the maximum installed capacity (Eq. (19)).

$$0 \le P^{E}_{e,t,y} \le I^{\mathrm{E}}_{e,y} \quad e \in \mathcal{E}, t \in \mathcal{T}, y \in \mathcal{Y} \tag{19}$$

The lost load can never exceed the actual load of the node (Eq. (20))

$$0 \le P^{\mathrm{D}-}_{n,t,y} \le \gamma_y \cdot d^{\mathrm{load}}_{n,t,y} \quad n \in N, t \in T, y \in Y \tag{20}$$

A.6. Network representation

To represent power flows in the AC network, we use the cycle-based formulation of Kirchhoff's voltage law, which leads to the sum of all potential changes in each cycle to be zero [35]. We take the cycle incidence matrix $\mathrm{h}_{o,l}$ and the line reactance x_a to calculate the line flows F^{A} and obtain a representation in our framework as in Eq. (21).

$$\sum_{a} \mathrm{h}_{o,a} \cdot \mathrm{x}_a \cdot F^{\mathrm{A}}_{a,t,y} = 0 \quad o \in O, t \in T, y \in Y \tag{21}$$

The flows F on the AC and DC lines in the framework must then not exceed thermal capacity limits p^{+} reduced by the transmission reliability margin v. This holds true for positive and negative flow directions (Eqs. (22)–(25)).

$$F^{\mathrm{A}}_{a,t,y} \le \mathrm{p}^{+}_{a} \cdot (1-\mathrm{v}) \qquad l \in \mathcal{A}, t \in \mathcal{T}, y \in \mathcal{Y} \tag{22}$$

$$F^{\mathrm{A}}_{a,t,y} \ge -\left[\mathrm{p}^{+}_{a} \cdot (1-\mathrm{v})\right] \quad l \in \mathcal{A}, t \in \mathcal{T}, y \in \mathcal{Y} \tag{23}$$

$$F^{\mathrm{D}}_{d,t,y} \le \mathrm{p}^{+}_{d} \cdot (1-\mathrm{v}) \qquad d \in (\mathcal{D} \setminus \mathcal{L}), t \in \mathcal{T}, y \in \mathcal{Y} \tag{24}$$

$$F^{\mathrm{D}}_{d,t,y} \ge -\left[\mathrm{p}^{+}_{d} \cdot (1-\mathrm{v})\right] \quad d \in (\mathcal{D} \setminus \mathcal{L}), t \in \mathcal{T}, y \in \mathcal{Y} \tag{25}$$

Fig. 6 displays the grid for our analysis. All onshore cables are used at a fixed capacity based on Hörsch et al. [37]. Connections to the energy islands in the North and Baltic Seas are optional and endogenously expanded. The red circles indicate the locations where electrolysers can be built.

In the past, national grid operators defined net transfer capacity margins limiting transfers between countries and allowing the national entities to adjust to their local optimum, which is especially problematic in congestion management because it does not fully utilise the physical potential [62]. Additionally, the concept lacks a mechanism for fast net transfer capacity adjustments to the weather and generation situation [63]. Net transfer capacity mechanisms have been gradually replaced since 2015 with flow-based market coupling (FBMC) and brought higher capacity allocations to the system. This utilises the infrastructure to a higher degree and is consequently more efficient. However, transmission system operators (TSOs) restrict commercial exchange to solve national grid congestion leading to lower-than-optimal capacity integration [64]. Naturally, this is not optimal in a European context. For reasons of simplification, with the chosen nodal European dispatch, we neglect national considerations for the dispatch.

A.7. General assumptions

Given the trade-off between complexity, accuracy, and computation time the framework does not predict the full European generation landscape in the investigated years but sketches scenarios under given assumptions. The assumptions are simplified and subject to high uncertainty, which is not accounted for in this framework. Furthermore, political decisions affect the future generation and transmission landscape and are subject to the social and economic considerations of the actors involved. The most critical assumptions are listed and shortly explained in the following.

- **Construction time:** any time between investment decision and completion is neglected in the framework.
- **Cross border exchange:** the framework does not allow for exchange with nodes or zones that are not included. Market boundaries are not considered as we solve the framework on a nodal basis.
- **Grid:** power lines are aggregated to create a less complex grid structure and prevent loop flows. A TRM is introduced as in [35]. Line losses are neglected.
- **Ramping:** no ramping of any technology is considered in the framework.

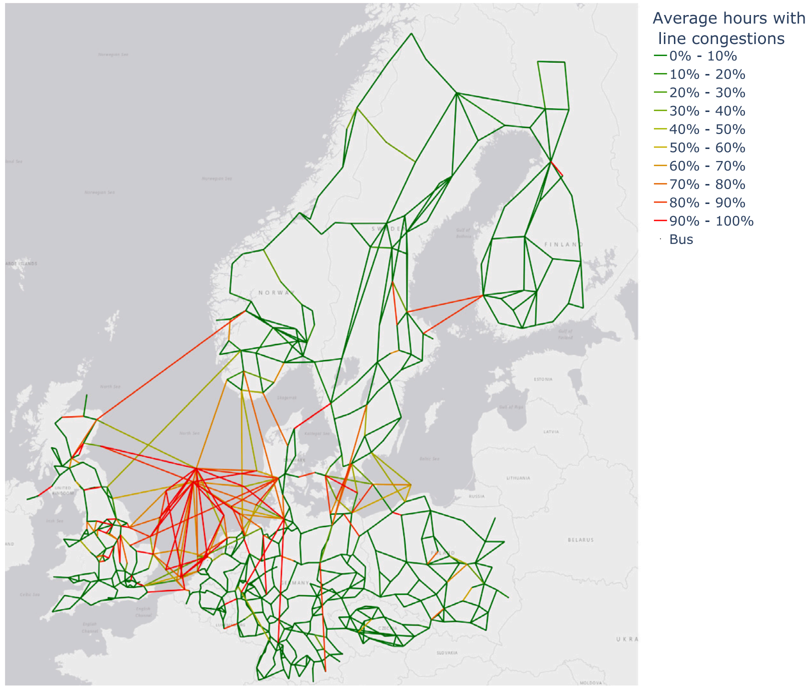

Fig. 7. Line congestions in the main analysis.

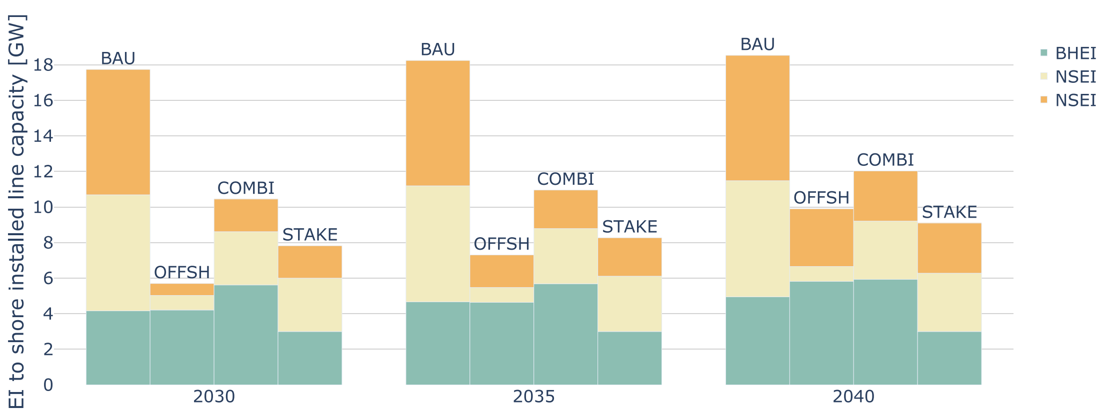

Fig. 8. Aggregated line capacity for the different cases in the main analysis.

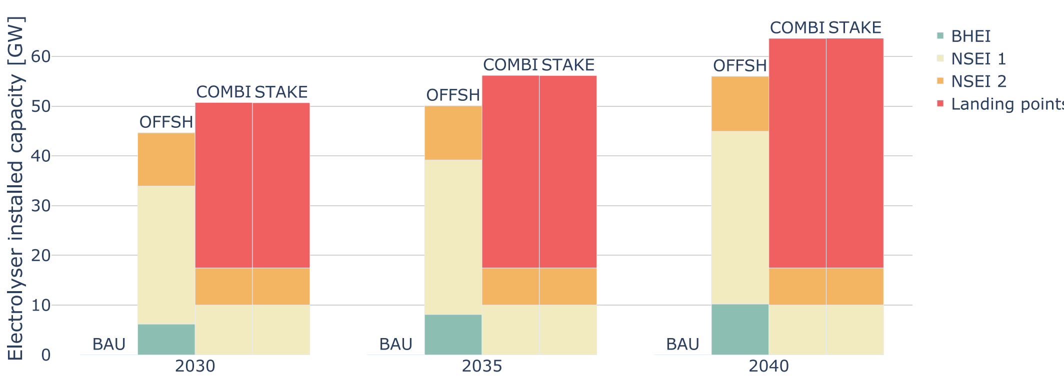

Fig. 9. Aggregated electrolyser capacity in the different cases.

Table 8
Hydrogen prices from electrolysis.

Source	Dinh et al. [53]	Haumaier et al. [54]	Meier [55]	Brunner et al. [56]	Bristowe and Smallbone [57]	Babarit et al. [31]	ICCT [58]
Base year	2030	2020	2014	2015	2030	2025	2050
Hydrogen price	5 €/kg	6.2–20.2 €/kg	5.20–106.10 €/kg	1.4–6.8 €/kg	3.4–5.7 €/kg	2.34 €/kg	6.79 €/kg[a]

[a]Median of European grid connected projects, collected from public sources.

Table 9
Parameters for electrolysis.

Source	Technology	Year	Size [MW]	CAPEX electrolyser [€/kW]	OpEX electrolyser	Efficiency [%]	Lifetime
Fraunhofer ISE [30]	PEM	2030	100 MW	502	15 €/kW	82	40,000–70,000 h
	Alkaline	2030	100 MW	444	20 €/kW	79	60,000–80,000 h
Danish Energy Agency [29]	Alkaline	2030	100	450	2% CAPEX/year	–	100,000 h
Dinh et al. [53]	PEM	2030	90 MW	600	2% CAPEX/year	–	60,000–110,000 h
IRENA [59]	Alkaline	2025	–	480	2% CAPEX/year	68	90,000 h
	PEM	2025	–	700	2% CAPEX/year	65	50,000 h
NREL [60]	PEM	–	1MW	234	–	70	–
Brunner et al. [56]	–	2015	–	500–1000	–	70–80	20a
Bristowe and Smallbone [57]	PEM	2030	20MW	300	5% CAPEX/year	82–90	70,000–150,000
Babarit et al. [31]	Alkaline	2025	5MW	600	3% CAPEX/year	66	20a
Parra et al. [61]	Alkaline	2030	–	400–1700	1.7–9.2% CAPEX/year	–	–
	PEM	2030	–	400–800	1.8–14.6% CAPEX/year	–	–

Table 10
Key values for the sensitivity analysis. Offshore and onshore electrolysis and non-restricted cable extension included. Thermal generation here includes using the fuels coal, gas, lignite, and oil.

		Objective value	Aggregated electrolyser capacity [GW]			Aggregated cable capacity [GW]			Curtailment [TWh]			Thermal generation [TWh]		
			2030	2035	2040	2030	2035	2040	2030	2035	2040	2030	2035	2040
COMBI	Offshore	1.15E+11	17.5	17.5	17.5	10.9	13.2	15.2	2.3	2.0	1.6	–	–	–
	Onshore		33.2	38.7	46.1	10.4	11.0	12.0	7.9	13.1	19.5	474.7	451.7	495.7
Low H_2	Offshore	1.26E+11	14.7	14.7	14.7	14.0	15.9	17.4	4.8	4.5	4.2	–	–	–
	Onshore		28.5	34.1	40.9	8.9	9.9	10.7	8.6	14.0	21.5	450.6	442.5	487.7
High H_2	Offshore	1.02E+11	17.7	17.7	17.7	13.3	13.3	15.9	0.5	0.8	0.9	–	–	–
	Onshore		50.5	50.5	53.5	10.8	10.8	11.1	7.2	12.0	18.2	798.4	476.8	510.9
High CO_2	Offshore	2.12E+11	16.2	16.2	16.2	15.5	19.0	25.1	2.4	1.6	0.9	–	–	–
	Onshore		32.8	38.5	44.6	9.9	12.3	13.8	8.3	15.1	24.9	452.5	442.6	433.0
Network	Offshore	1.10E+11	16.2	16.2	16.2	11.3	14.9	18.0	2.0	1.5	1.4	–	–	–
	Onshore		30.7	36.4	44.2	8.3	9.2	9.6	7.8	12.7	19.1	449.2	424.9	471.0
Low OPEX	Offshore	1.12E+11	21.5	21.5	21.5	11.7	14.2	16.8	1.6	1.3	1.2	–	–	–
	Onshore		34.6	39.6	47.3	7.7	8.7	9.4	7.3	12.3	18.5	474.9	452.1	496.2

- **Must-run obligation and unit commitment:** we disregard unit commitment and must-run obligations of for example combined heat and power plants (CHPs).
- **Storage:** hydrogen storage is neglected.
- **Hydrogen:** hydrogen is expected to be sold at a fixed price. Any considerations regarding transport and consumption are not reflected.
- **Economics:** interest rate and cost parameters are assumed to be constant over time.
- **Decommissioning:** decommissioning does not take place or incurs a cost.

Appendix B. Hydrogen and electrolysis data collection

Hydrogen price forecasts vary significantly depending on the sources. For this study, we assume a price of €3.23/kg, which is based on Glenk and Reichelstein [33] and provides a well-acknowledged calculation of the price for renewable-based hydrogen. The calculation follows a thorough bottom-up approach and the value used is representing the conservative approximation. To illustrate the range of prices, Table 8 provides an overview of different price ranges listed in earlier studies.

Besides the hydrogen prices, our model needs input on the cost of electrolysis equipment. Table 9 summarises the results of our literature survey to obtain the relevant parameters that we use in our case study and which are listed in Table 1. The final values are based on the reference data by Fraunhofer ISE (2021), Babarit et al. [31], and Danish Energy Agency [29]. For onshore installations, we use the mean of the three aforementioned sources resulting in €425,000/MW_e. This is an optimistic estimation acknowledging scaling effects of the technology. We add expenses for hydrogen compression to this with a markup of €25,000/MW_{LHV}. For offshore installations, we increase the onshore cost by 30% due to higher costs for construction work and materials for use at sea [65]. To connect offshore electrolysers, the cost for pipeline infrastructure is accounted for by €16,000/MW [66]. This adds up to €645,000/MW for offshore installations. For both types of electrolysers, we assume fixed OPEX to be 5% of CAPEX per year which allows replacing the stacks every 10 years over a lifetime of 30 years [67]. This fixed OPEX is a conservative assumption and resembles the worst-case estimations of Danish Energy Agency [29] and BEIS [68].

Appendix C. Further results

This section collects additional figures and tables to illustrate the results.

Table 11
Thermal power plant use in TWh including the sensitivity analysis.

		Main analysis			High CO_2 price			Low H_2 price			High H_2 price			Network expansion		
		2030	2035	2040	2030	2035	2040	2030	2035	2040	2030	2035	2040	2030	2035	2040
BAU	Oil	3.5	4.9	6.2	–	–	–	–	–	–	–	–	–	–	–	–
	Gas	136.2	189.1	194.1	–	–	–	–	–	–	–	–	–	–	–	–
	Coal	152.1	160.5	196.9	–	–	–	–	–	–	–	–	–	–	–	–
	Lignite	145.7	76.4	29.4	–	–	–	–	–	–	–	–	–	–	–	–
	Nuclear	325.4	315.0	302.7	–	–	–	–	–	–	–	–	–	–	–	–
	Biomass	53.4	51.6	50.4	–	–	–	–	–	–	–	–	–	–	–	–
	Sum	816.3	797.5	779.7	–	–	–	–	–	–	–	––	–	–	–	–
OFFSH	Oil	3.4	4.5	5.8	–	–	–		–	–	–	–	–	–	–	–
	Gas	151.4	205.3	207.4	–	–	–	–	–	–	–	–	–	–	–	–
	Coal	147.3	160.9	201.2	–	–	–	–	–	–	–	–	–	–	–	–
	Lignite	169.6	77.4	25.6	–	–	–	–	–	–	–	–	–	–	–	–
	Nuclear	404.3	399.9	395.0	–	–	–	–	–	–	–	–	–	–	–	–
	Biomass	71.5	71.0	67.2	–	–	–	–	–	–	–	–	–	–	–	–
	Sum	947.5	919.0	902.2	–	–	–	–	–	–	–	–	–	–	–	–
COMBI	Oil	3.3	4.4	5.7	3.3	4.3	5.6	3.3	4.3	5.6	3.3	4.9	5.1	2.3	3.2	4.6
	Gas	153.2	208.6	211.1	370.7	234.3	224.2	370.7	234.3	224.2	212.3	235.5	232.7	138.6	194.1	195.6
	Coal	147.1	161.2	201.3	211.7	160.6	203.6	211.7	160.6	203.6	182.8	185.0	178.1	134.8	149.9	193.1
	Lignite	171.1	77.5	25.7	212.7	77.5	22.8	212.7	77.5	22.8	54.1	17.1	15.5	173.5	77.6	23.1
	Nuclear	409.1	405.4	401.2	412.2	410.2	405.4	412.2	410.2	405.4	406.1	401.2	393.5	409.4	405.6	401.1
	Biomass	71.6	71.2	67.9	72.0	71.8	71.0	72.0	71.8	71.0	71.3	69.5	65.9	71.6	71.1	70.7
	Sum	955.5	928.4	913.0	1282.5	958.7	932.5	1282.5	958.7	932.5	929.9	913.3	890.7	930.2	901.6	888.3
STAKE	Oil	3.3	4.5	5.7	–	–	–	–	–	–	–	–	–	–	–	–
	Gas	153.1	208.6	211.2	–	–	–	–	–	–	–	–	–	–	–	–
	Coal	147.1	161.2	201.3	–	–	–	–	–	–	–	–	–	–	–	–
	Lignite	171.2	77.5	25.7	–	–	–	–	–	–	–	–	–	–	–	–
	Nuclear	409.1	405.5	401.2	–	–	–	–	–	–	–	–	–	–	–	–
	Biomass	71.6	71.2	67.9	–	–	–	–	–	–	–	–	–	–	–	–
	Sum	955.4	928.5	913.0	–	–	–	–	–	–	–	–	–	–	–	–

For our analysis, we use a system model with a detailed grid representation of the transmission grid. By doing so, we can observe the utilisation of the power grid from the results. Fig. 7 shows the average hours with line congestion in our main analysis. The newly built DC cables offshore have a high utilisation rate, and so do most interconnectors. Except for the German onshore grid, most other regions have well utilised, but not fully congested grids. Note that this graph depicts the situation after accounting for a transmission reliability margin of 30%.

Figs. 8 and 9 display the capacities of line expansion and electrolyser expansion graphically. This allows comparing the effect of different capacity expansion options among the cases. Comparing the two, electrolyser capacity onshore and offshore leads to significantly lower grid connection capacities of the energy islands. Aggregated electrolyser capacity will at most be 55 GW.

Table 10 summarises the key values of our sensitivity analysis and compares to the *COMBI* case of our main analysis. Similar to the key values of our main analysis, we compare electrolyser capacity, cable expansion, curtailment, and thermal generation. As mentioned in the discussion section, the results indicate a high sensitivity of the results for a change in hydrogen market prices. Capacities of cables and electrolysers do not change drastically for onshore grid expansion, but costs for the dispatch and investment are lower. In addition, the case *low OPEX* shows results for a sensitivity model run with 2% instead of 5% fixed OPEX of electrolysers as displayed in some data sources (cf. [66]).

Finally, Table 11 summarises the thermal power plant use across the cases including the sensitivity analysis. This overview allows for an in-depth analysis of the usage of thermal capacity and the possible contribution of the generation to hydrogen production.

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