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Offshore wind power market values in the North Sea – A probabilistic approach

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ABSTRACT

Offshore wind capacity is expected to grow significantly in North Sea countries over the next decade. This study analyses the expected market value and economic potential of offshore wind developments for various grid connection strategies using the Norwegian continental shelf as a case. The economic analyses rely on an energy sector model with a fine temporal and spatial resolution that covers the Northern European power and heat market. The novelty of this study is that it explicitly addresses uncertain economic and political developments, which are incorporated through Monte Carlo simulations. The highest market values are obtained for wind parks with 3 GW installed capacity if allowed to flexibly transmit electricity to several markets with a market value of 39 ± 3 €/MWh. The least profitable alternative is a wind park connected radially to Norway, which has a market value of 30 ± 2 €/MWh. We find a substantial reduction in the value factor from 1.02 ± 0.03 to 0.94 ± 0.02 when increasing the offshore capacity from 3 GW to 8 GW. The economic potential of Norwegian offshore wind, i.e., the profitable investment level without subsidies, is estimated to be 2.8 ± 1.1 GW. The market value of offshore wind power increases substantially if the wind installations are connected to several markets.

1. Introduction

Offshore wind power has received increased interest in Europe and is regarded as one of the main long-term solutions for carbon neutrality in the European energy system. The current capacity installed in the EU is just over 25 GW, while the European Commission's ambitious goals for offshore wind installations in Europe are to achieve 60 GW by 2030 and 300 GW by 2050 [1]. About 80% of the current offshore wind capacity in Europe is located in the North Sea, and in the European context, the North Sea areas stand out as particularly appealing for offshore wind expansion from a wind resources viewpoint. Despite very good wind resources, the Norwegian part of the North Sea does not yet have any commercial offshore wind capacity [2]. The main reasons for this are that the marine area close to the Norwegian coastline is primarily suitable for floating turbines. Norway currently has an electricity export surplus and Norwegian electricity prices are relatively low compared to the price level on the continent. However, due to increasing public opposition to onshore wind, and the prospect of higher electricity demand as a result of direct and indirect electrification of the transport, building, and industry sectors offshore wind has recently been moved further up on the agenda in Norwegian political debate [3,4].

Although from a domestic viewpoint many countries would tend to favour a radial connection to their own country to ensure lower electricity prices for their inhabitants and industries, the European Commission [1] considers hybrid offshore projects with a meshed grid[1] to be a promising concept in order to reduce costs and increase value, as well reducing the environmental impact of the system as a whole.

Several previous studies point out the advantages of meshed grid solutions for offshore wind in the North Sea [5–10]. Konstantelos et al. [6] find that a meshed grid is profitable in most cases due to a reduced need for backup capacity and reduced investment costs relating to the grid as a whole. A meshed grid solution is particularly profitable if there is a high penetration of variable energy in the system. Konstantelos et al. [6] and Dedecca and Hakvoort [7] find a significant imbalance in cost and revenue sharing between importing and exporting markets, which may reduce the political interest in such projects. In their literature review, Dedecca and Hakvoort [7] conclude that the majority of offshore wind studies focus on investment in and operation of meshed grid

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[1] A meshed grid is a grid configuration that connects several wind farms with several connection points to land. A meshed grid allows a wind farm to be connected to other wind farms and multiple markets. This is regarded as a more robust grid configuration than a radial connection since it allows power to be transmitted where it is most needed.

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solutions, while system effects and offshore wind profitability remain less discussed.

Koivisto et al. [5] and Gea-Bermudez [10] have studied the combined effects of increased electricity demand, sector coupling, and offshore wind investment. They found that meshed offshore grids and sector coupling are prerequisites for large-scale development of offshore wind in multi-regional hubs in the North Sea [10]. Since a meshed grid allows for transmission to multiple regions, it increases the possibility of optimal investment in offshore wind [5].

Concepts related to physical installations such as windmills and grid development have been studied extensively in recent years, while the economic implications of offshore wind in the North Sea have been less discussed. Furthermore, despite major technological and market uncertainties, most previous economic analyses of offshore wind use relatively few cases or scenarios in their analyses of expected investment levels or revenues from offshore wind. Also, few studies have taken uncertainties relating to the future development of the energy system into account. Most of the studies that touch on stochasticity in a modelling framework mainly focus on weather risks [11–13], while uncertainties related to markets and technologies remain unexplored.

In summary, while several studies focus on offshore wind and grid development in the North Sea, few studies have so far addressed the impacts of market and technological uncertainty by applying a probabilistic approach. The objective of this study, therefore, is to quantify the expected market value of offshore wind power in the North Sea while explicitly taking uncertainties related to grid connections, markets, and technology development into account. In this study, we use the concept of market value, which is the average revenue from a specific technology [14]. Market value is a special relevant concept when comparing the system value of different renewable technologies that all have low marginal costs [15–19].

The study uses three scenario approaches. The first approach assumes endogenous investment in offshore wind in Norway where the investment is based on the economically optimal investment level. The second approach assumes an exogenous offshore investment level in Norway at 3–8 GW. In the last approach, we look at a specific area of the North Sea and find the value of offshore wind when the field is connected to different markets. With this setup, we are able to answer the three main research questions: Q1 – What are the market effects of offshore wind investment in Norway? Q2 –How much offshore wind

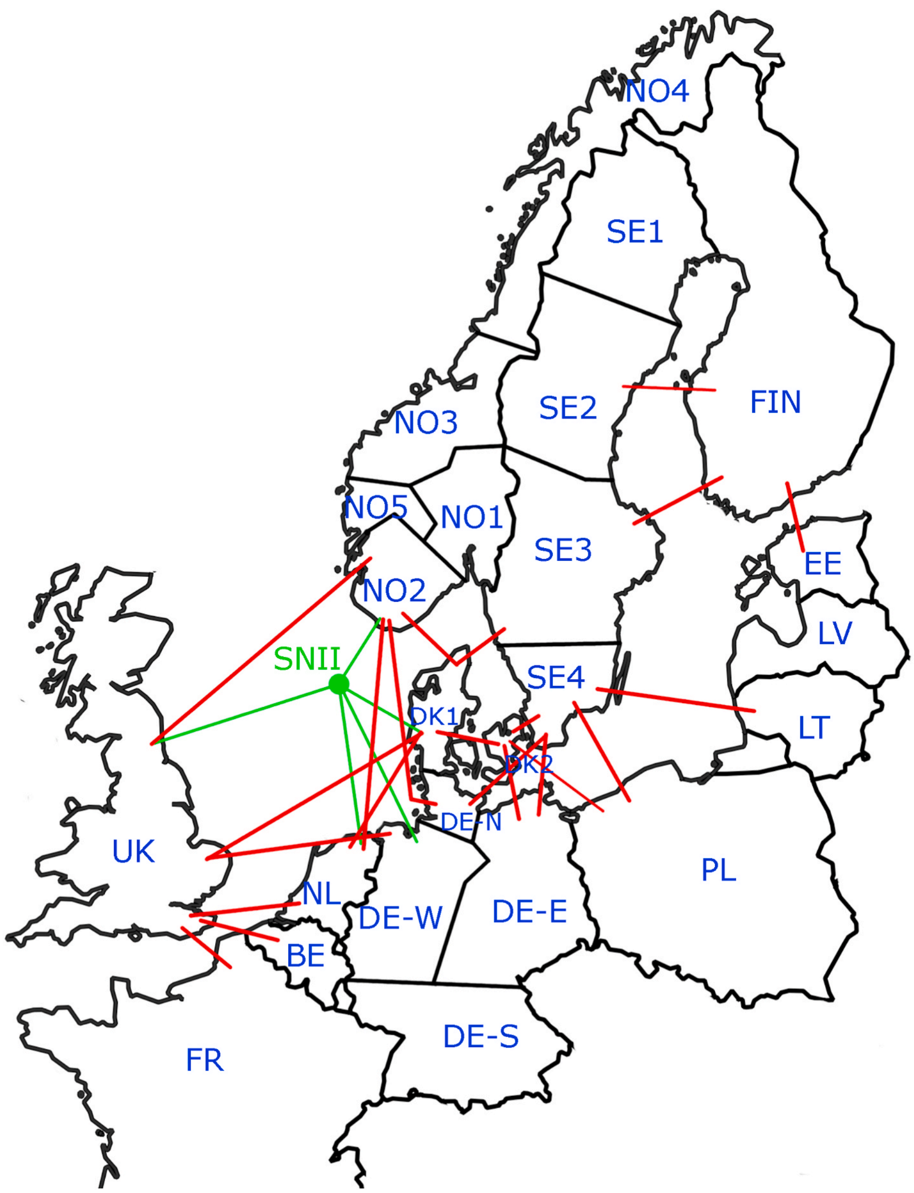

Fig. 1. Regional coverage of Balmorel with offshore interconnectors. Power lines to Søndre Norsjøen II (SNII) field are only included in the last approach.

power is it economically feasible to develop? Q3 – What would the market value be in the case of connection to several spot markets with and without being used as a transmission hub? The effects are quantified for the Northern European energy market in 2040.

2. Methods

2.1. Balmorel

Balmorel is a cost-minimising energy sector model that has been under continuous development since 2001 [20,21]. The model and data are open source and available at GitHub Repository [22]. The model uses a bottom-up approach and covers the combined electricity and heat markets in Northern Europe (Norway, Sweden, Finland, Estonia, Latvia, Lithuania, Poland, Germany, Denmark, Belgium, Netherlands, France, and the UK); see Fig. 1 for the regional coverage of the electricity market. Balmorel is particularly suitable for investment analyses and 'what-if' studies. The objective function is to minimise the total cost of fulfilling the energy demand at each timestep and in each region. The energy demand is divided into different user groups in order to cover different demand profiles and flexibility options. Electricity demand is divided into exogenously defined categories, which are residential, industrial, and transportation. The model also contains some demand-side flexibility options which are endogenous heat production, demand response [23], and smart charging schemes for electrical vehicles [24]. A flow chart of the Balmorel model is provided in Fig. 2.

The Balmorel structure allows for hourly resolution, but due to the complexity of the model, the full hourly resolution is seldom used. In this study, 288 timesteps are used in order to cover the full yearly variability of renewable time profiles, and a time aggregation algorithm has been applied. The algorithm maintains the maximum, minimum, and mean values within each week. In order to satisfy the demand at every timestep, the model selects the optimal combination of generation technologies, electricity transmission, energy storage, and demand response to minimise the yearly costs. The model allows investment in new generation capacities and permits the allocation of production between exogenously defined capacities (Table 1) and new endogenous capacities. The model includes energy production from all frequently used energy sources, including wind (onshore and offshore), solar (solar collectors and PV), hydropower (run-of-river, reservoir, and pump), biomass (biogas, bio-oil, straw, woodchips, and pellets), fossil fuels (coal, lignite, fuel oil, and natural gas), and other fuels such as waste and nuclear power. Fuel prices are based on figures from the International Energy Agency (IEA) [25], nuclear generation costs are based on Entso-E [26], and other costs have primarily been based on IEA [27] and Energistyrelsen [28]. The availability of renewables is geographically restricted with regard to techno-economic assumptions and social acceptance. We assume that new investment will take place in the most economically attractive locations available in the model.

The model contains all existing and planned transmission lines between the spot areas [29] (see Fig. 1 for existing offshore grid connections between the modelled countries). In addition, we allow for up to 2 GW of endogenous investments in transmission lines within and to and from the Nordic countries, and up to 5 GW in the rest of the model. Only transmission of electricity is allowed, which implies that produced heat must be consumed in the production region.

Table 2 shows the generation costs, full load hours and maximum allowed investment level for offshore wind power in the modelled countries. The variations between the maximum and minimum values represent the most and least attractive locations within each country.

Table 1
Exogenously defined generation capacity in the Nordic countries and the rest of the model in 2040. Unit: GW.

	Norway	Sweden	Denmark	Finland	Rest of the model
Biomass		5		1	22
Coal					33
Heat pump		17		13	
Natural gas				2	65
Other fossils		3		2	8
Solar		1	2		82
Waste				1	4
Onshore wind	3	4	1	2	33
Offshore wind			1		22
Nuclear	See scenario assumption in Table 3				
Hydro	See scenario assumption in Table 3			3	176

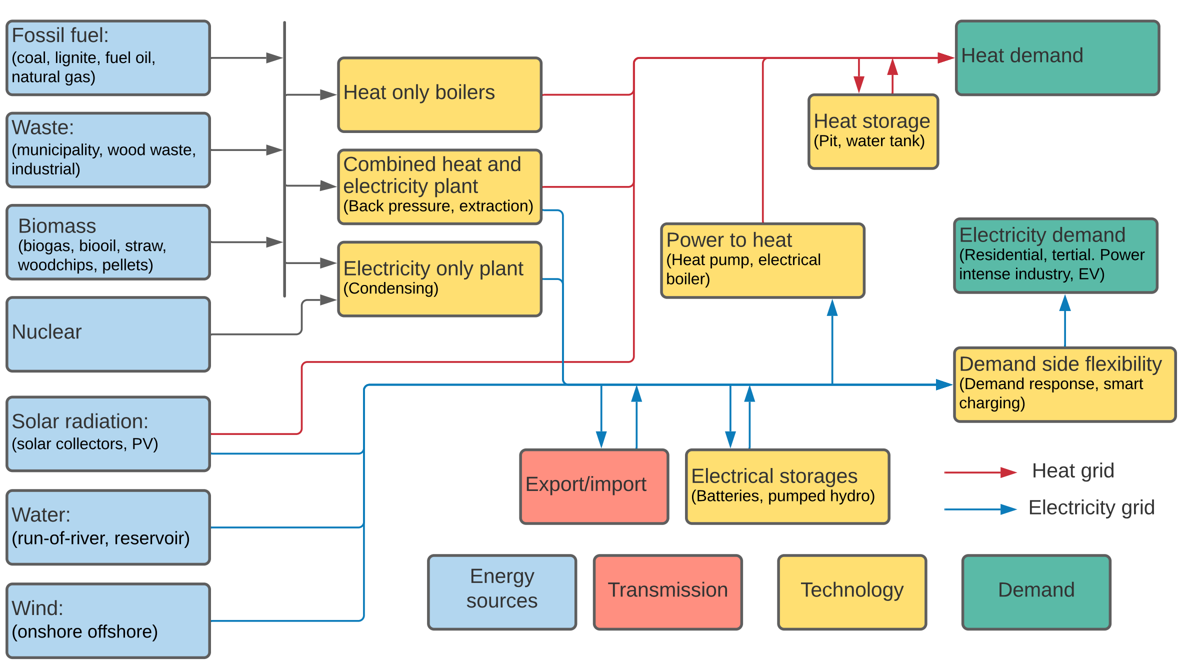

Fig. 2. Flowchart showing the Balmorel model.

Table 2
Base LCOE for offshore wind power investment. Capital cost is based on a 6% interest rate and a 30-year lifetime. Variation between maximum and minimum is the difference between the most and least economically attractive areas. Source [5,27,28,30] and own estimates.

	LCOE [€/MWh]	Full load hours [h]	Allowed installed capacity [GW]		
	low	high	low	high	max
BE	38	38	4704	4704	8
DE	34	41	4657	4951	75
DK	32	41	4540	4993	50
EE	40	40	4357	4357	19
FI	45	45	3894	3894	35
FR	40	40	4369	4369	53
LT	39	39	4510	4510	2
LV	40	40	4415	4415	13
NL	38	40	4650	4787	68
NO	36	46	4090	5135	90
PL	38	38	4691	4691	11
SE	38	44	3912	4651	43
UK	34	42	4357	5057	161
SNII	32	34	4711	5135	3

2.2. Uncertainty modelling with use of Monte Carlo simulations

The future development of the Northern European energy sector is uncertain. In order to account for some of this uncertainty, in this study we conduct a formal uncertainty analysis using Monte Carlo simulations [31,32]. The basic concept of Monte Carlo simulations is to investigate the scope of different outputs given multiple uncertainty inputs. This is done with several independent deterministic simulations. Each of the independent simulations is based on a random set of input parameters that are sampled from the input uncertainty ranges. With a sufficiently high number of independent simulations, it is possible to cover the likely output ranges. The strength of using Monte Carlo is that all changes are solely done on the input data, hence we do not need to do any changes to the core model. Since Monte Carlo simulations are time-consuming [31], we use a sampling strategy in this study called Latin hypercube sampling [33]. This sampling strategy is regarded as a fast and reliable sampling method for computationally demanding models [34].

Latin hypercube sampling is a sampling technique that may be described by the following steps: 1) the uncertainty range for all variables is divided into n segments; 2) a random value is selected from each segment; 3) a scenario is created by selecting one value from each variable without replacement. This results in n scenarios from one hypercube. Steps one to three are then repeated until a sufficient number of independent scenarios have been produced. This method ensures that the entire input uncertainty space is mapped using a relatively low number of simulations. The Latin hypercube used in this study is equal in size to the number of independent variables included ($n = 68$), and we use 500 independent model runs for each scenario.

2.3. Uncertainty distributions

The Monte Carlo simulations are based on the different uncertainty distributions presented in Table 3, which is an updated version of the uncertainty distribution used in Jåstad et al. [15]. All distributions are assumed to be triangular except for fuel costs, which are assumed to have a normal distribution. The same uncertainty ranges and the same Monte Carlo simulations have been applied to all cases in this study to ensure the cases are directly comparable. The exact values included in the Monte Carlo simulations are shown as supplementary information. In total, 69 different uncertainty parameters are included and distributed across seven different categories. The first category is exogenously defined capacity for hydropower, nuclear power, and onshore wind power in Norway. Nuclear power is a politically sensitive topic in many countries and is therefore regarded as an input uncertainty. Hydropower capacity in Norway and Sweden is close to fully developed and new expansion mainly consists of upgrading existing plants and smaller projects. Finally, onshore wind is a politically sensitive topic in Norway and the socially accepted level is highly uncertain. We do therefore include onshore wind as an uncertainty parameter in this study. Categories two to four are different technology costs, which must be exogenously defined in the model. Here, we include different learning outcomes based on information from the Danish Energy Agency [28]. Categories five and six are future fuel prices and carbon prices, while category seven is demand based on Chen et al. [35] and NVE [36].

2.4. Approaches

2.4.1. The economic potential of offshore wind delivered to the Norwegian market

In the first approach, we quantify the economically optimal investment level of offshore wind on the Norwegian continental shelf. Here, the investment level is chosen endogenously among all available technologies and regions, but only radial connection to the Norwegian market is allowed. This approach compares the profitability of Norwegian offshore wind power compared with other technologies and countries. This approach only gives the possible offshore investments if the techno-economical constraints are taken into account.

The endogenous estimation of offshore wind capacity entails great uncertainty when it comes to cost, weather, technological readiness, and subsidies. Since this leads to an uncertain political and economic framework, we will take a closer look at exogenously defined capacity levels in the next section.

2.4.2. Offshore wind market impacts

To quantify the expected market value and profitability of offshore wind in Norway, this approach is based on pre-determined investment levels for offshore wind. Here, we assume an offshore wind capacity in Norway of 3 GW, 5.5 GW, and 8 GW. Previous studies have regarded these capacities to be technically feasible [41] and they are also aligned with stated policy goals [3,4,36,38,39,42]. In this approach, we define the capacities at a national scale, and the model selects the most suitable location based on the costs in Table 4 below. Only a radial connection to Norway has been considered in these cases.

2.4.3. Impact of access to multiple markets

To assess how the profitability of offshore wind power is affected by access to one or multiple power markets, we compare model runs with a radial connection to Norway to cases where the wind farms are connected to other countries around the North Sea. In these scenarios, we study the field Søndre Norsjøen II (SNII) as a case. SNII is an offshore area located in the Norwegian sector but close to the Danish sector (Fig. 1). The area is suitable for bottom-fixed offshore turbines and is likely to be the first area in Norway that is opened for commercial offshore wind power [4]. Since SNII is in the middle of the North Sea, it could be of interest to transmit the power to several markets (Fig. 3). Here, we allow endogenous investment in transmission lines based on the costs shown in Table 5. First, we test the radial connection to one spot market, to southern Norway (NO2) (case 1), the UK (case 2), and Germany (case 3), respectively. Thereafter, we run two configurations where SNII is connected to several spot markets, determined endogenously by the model. In these runs, we allow SNII to be connected to all countries around the North Sea. In the first configuration (case 4), we only allow electricity to be sent from SNII and in the second configuration (case 5), we allow electricity to be sent to and from SNII, i.e., assuming SNII to be an offshore hub. The offshore wind power capacity in these model runs is set exogenously to 3 GW and the wind characteristics as far shore regions in NO2, as shown in Table 4. We allow endogenous investment in offshore wind technologies in the other regions. There is a cap on the maximum investment in transmission lines from SNII corresponding to 3 GW, which is the planned maximum wind

Table 3
Uncertainty parameters. Sources: [26,28,35–40] and own assumptions.

			Min	Average	Max	Std	Unit	Source
Exogenous capacity	Nuclear - Sweden	triangular	0.0	5.3	11		GW	[35]
	Nuclear - Finland	triangular	4.0	4.3	7.2			[35]
	Nuclear - France	triangular	32	42	55			[35]
	Nuclear - UK	triangular	6.0	8.0	17			[35]
	Onshore wind - Norway	triangular	20	25	35			[37–40]
	Hydropower - Norway	triangular	33	34	39			[36], own
	Hydropower - Sweden	triangular	16	17	20			[36], own
Investment cost	MSW	triangular	−27%	0.0%	37%		%	[28]
	Onshore wind	triangular	−17%	0.0%	75%			
	Offshore wind	triangular	−20%	0.0%	10%			
	Solar collector	triangular	−13%	0.0%	14%			
	Solar PV	triangular	−36%	0.0%	22%			
	Pellets - CHP	triangular	−24%	0.0%	46%			
	Pellets - heat only	triangular	−17%	0.0%	46%			
	Woodchips - CHP	triangular	−23%	0.0%	43%			
	Woodchips - heat only	triangular	−29%	0.0%	92%			
	Heat pump and electric boilers	triangular	−22%	0.0%	38%			
	Natural gas heat only - heat only	triangular	−30%	0.0%	400%			
	Biogas - CHP	triangular	−6.0%	0.0%	41%			
	Natural gas - CHP	triangular	−33%	0.0%	63%			
O&M	MSW	triangular	−27%	0.0%	29%			
	Onshore wind	triangular	−20%	0.0%	20%			
	Offshore wind	triangular	−20%	0.0%	10%			
	Solar collector	triangular	−13%	0.0%	0.0%			
	Solar PV	triangular	−26%	0.0%	29%			
	Pellets - CHP	triangular	−32%	0.0%	31%			
	Pellets - heat only	triangular	−22%	0.0%	33%			
	Woodchips - CHP	triangular	−39%	0.0%	31%			
	Woodchips - heat only	triangular	−79%	0.0%	150%			
	Heat pump and electric boilers	triangular	−25%	0.0%	40%			
	Natural gas heat only- heat only	triangular	−41%	0.0%	120%			
	Biogas - CHP	triangular	−33%	0.0%	100%			
	Natural gas - CHP	triangular	−25%	0.0%	75%			
Conversion effectivity	MSW	triangular	−20%	0.0%	14%			
	Pellets - CHP	triangular	−8.0%	0.0%	41%			
	Pellets - heat only	triangular	−12%	0.0%	1.0%			
	Woodchips - CHP	triangular	−10%	0.0%	43%			
	Woodchips - heat only	triangular	−12%	0.0%	14%			
	Heat pump and electric boilers	triangular	−23%	0.0%	1.0%			
	Biogas - CHP	triangular	−11%	0.0%	2.0%			
	Natural gas - heat only	triangular	−10%	0.0%	2.0%			
	Natural gas - CHP	triangular	−20%	0.0%	5.0%			
Fuel prices	Woodchips	normal		7.2		0.60	€/GJ	[35]
	Pellets	normal		9.0		1.0		
	Coal	normal		2.9		0.90		
	Natural gas	normal		7.4		2.0		
	Fuel oil	normal		11.0		11.7		
Carbon price		triangular	28	83	200		€/tonne	[35]
Demand	Residential - Norway	triangular	63	77	92		TWh	[35–40]
	Industrial - Norway	triangular	69	83	97			
	EV - Norway	triangular	12	16	21			
	Residential - Sweden	triangular	75	82	88			
	Industrial - Sweden	triangular	67	81	82			
	EV - Sweden	triangular	11	22	36			
	Residential - Denmark	triangular	25	29	31			
	Industrial - Denmark	triangular	24	30	69			
	EV - Denmark	triangular	10	12	16			
	Residential - Finland	triangular	50	56	59			
	Industrial - Finland	triangular	33	51	69			
	EV - Finland	triangular	5.0	7.0	10			
	Belgium	triangular	96	106	118			[26,37–39]
	Germany	triangular	640	705	813			
	Estonia	triangular	9.0	11	13			
	France	triangular	506	570	653			
	Lithuania	triangular	15	16	18			
	Latvia	triangular	11	13	15			
	Netherlands	triangular	119	139	168			
	Poland	triangular	200	207	218			
	UK	triangular	390	436	524			

Table 4
Base offshore wind power data in Norway. Own estimates based on [28,30,43,44].

	LCOE [€/MWh]			Full load hours [h]			Max capacity [MW]		
	Nearshore	Far shore low costs	Far shore high costs	Nearshore	Far shore low costs	Far shore high costs	Nearshore	Far shore low costs	Far shore high costs
NO2		37	40		4711	5135		6496	25495
NO3	36	40	42	4090	4296	4636	115	12211	15351
NO4	37	41	46	4390	4392	4425	175	11062	16342
NO5		38			4758			2451	

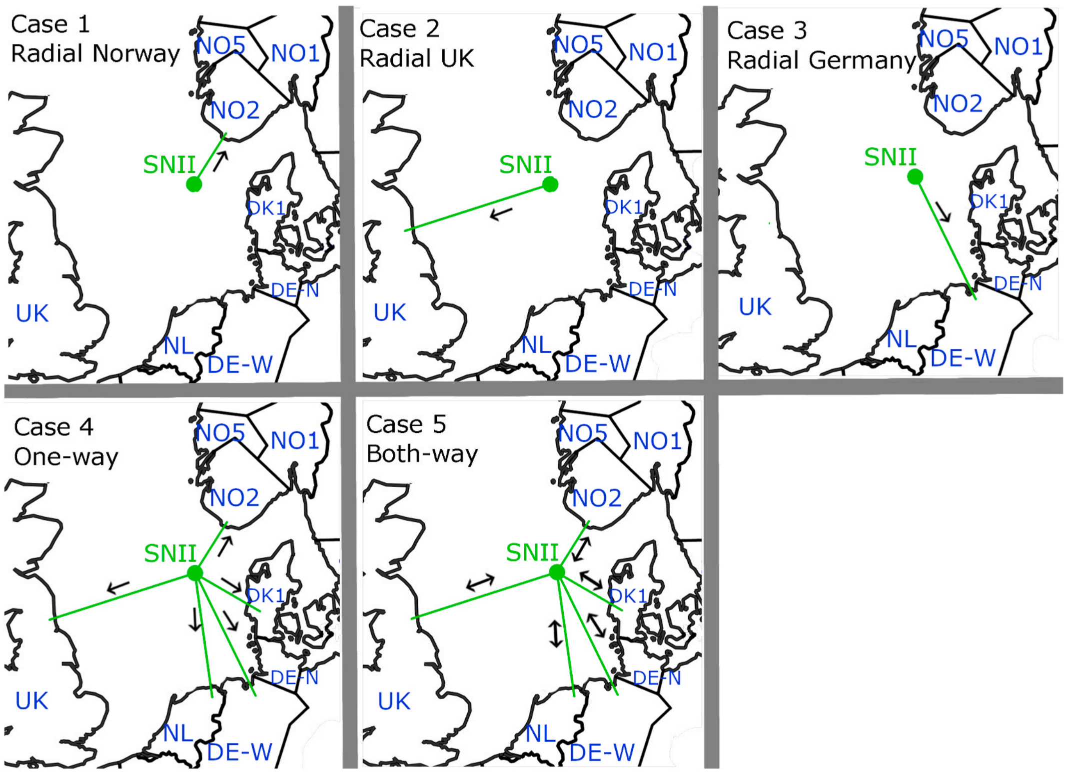

Fig. 3. Graphically explanation of the different cases in for transmission grid from SNII.

Table 5
Assumed investment costs between the SNII region and connection point in the neighbouring grid. Cost per km is estimated based on Entso-E [45] and is estimated to be 1315 €/MW/km.

	Assumed distance to the grid [km]	Total investment costs [€/MW]
NO2	311	409 592
UK	448	589 059
Netherlands	451	593 401
DK1	380	499 325
Germany	507	667 215

capacity at SNII.

3. Results and discussion

3.1. The economic potential of offshore wind delivered to the Norwegian market

The first approach quantifies the economic potential of offshore wind power assuming a radial connection to the Norwegian grid. With the given assumptions, the model finds it profitable to invest in offshore wind power installations in 93% of the simulations. The average offshore capacity in these cases is 2.8 ± 1.1 GW, with a maximum of 8.1

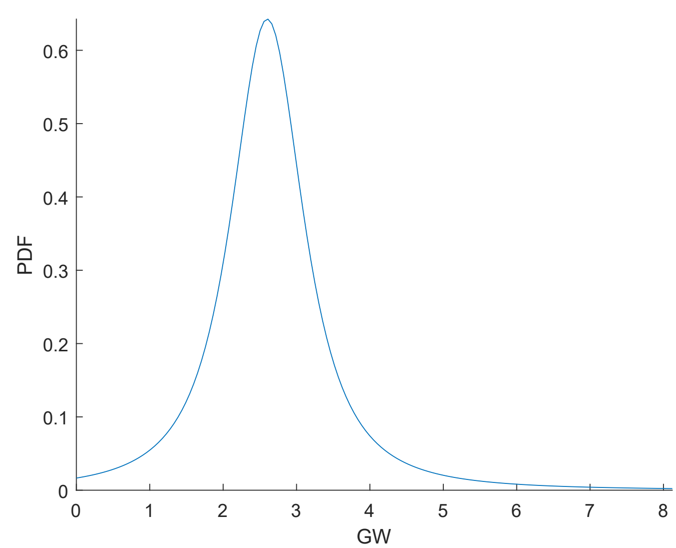

Fig. 4. Modelled range for endogenous offshore investment in Norway. Only scenarios with invested offshore capacity are included in the figures.

GW (Fig. 4). The average capacity estimate is slightly lower than found by Koivisto et al. [5] who estimate around 4 GW of offshore wind in Norway in 2040.

The modelled capacity of offshore wind power in Norway increases with decreasing offshore wind capital costs and maintenance costs. As expected, the Monte Carlo simulations estimate that the optimal investment level depends on a large set of market driving forces. In addition to gas and power prices, which largely determine the European power price levels, the assumed electricity demand as well as the nuclear power capacity in Sweden and hydropower capacity in Norway are decisive factors.

The modelled Norwegian electricity production in 2040 is 199 ± 7 TWh (Fig. 5). Hydropower remains by far the dominant technology, accounting for 75–80% of the total production. The variation in hydropower and onshore wind production primarily follows the forced input range shown in Table 3. When modelling investments in offshore wind endogenously and without any subsidies, the annual offshore wind production amounts to 13 ± 6 TWh, with a maximum production of 39 TWh.

3.2. Offshore wind market impacts

According to our model results, the expected power price in Norway in 2040 is 36 ± 2 €/MWh when assuming an offshore wind capacity of 5.5 GW. The model results indicate significant differences in market value between the various power generation technologies (Figs. 6 and 7). Reservoir hydropower stands out with a value factor of 1.60 ± 0.07 of the average market price. In addition, offshore wind has a significantly higher market value than ROR and solar PV since the latter two technologies have relatively low production shares in winter. The mean market value of onshore wind is as high as 34 ± 4 €/MWh (value factor 1.20 ± 0.09) with 5.5 GW of offshore wind, due to a high share of winter generation. However, it should be noted that we have constrained the capacity of onshore wind due to the substantial public opposition seen in Norway. As expected, power prices decline as we increase the predefined capacity of offshore wind power. Most notably, the market value of offshore wind declines by 0.92 €/MWh/GW (value factor reduction 0.015/GW), illustrating a substantial merit order effect. The offshore wind power market values are higher than the average electricity price for offshore wind investment up to 5.5 GW, while the merit order effects result in a market value lower than the market price in the 8 GW case.

Norwegian offshore wind production was found to be 4.7 ± 0.1 TWh/GW. In order to balance the increased variable generation with demand, net export from Norway has increased by 4.2 ± 0.4 TWh/GW, where most of the new export is directed toward Denmark (1.6 ± 0.4 TWh/GW), Sweden (1.3 ± 0.4 TWh/GW) and Germany (0.7 ± 0.3 TWh/GW). The increased level of offshore wind power results in reduced import of 1.4 ± 0.3 TWh/GW and a subsequent increase in export of 2.8 ± 0.3 TWh/GW. This shows that the increased variability between the hours when offshore wind power is introduced is to a large extent balanced by increased export to regions abroad. Due to the flexible transmission system, there are no significant changes in investments in Norwegian generation technologies when offshore wind investment increases. This shows that offshore wind in Norway is likely to influence Norwegian prices and trade more than energy production, assuming a fixed energy demand.

Norwegian power prices decline as expected when offshore capacity increases, by 37 ± 2 €/MWh at 3 GW, 36 ± 2 €/MWh at 5.5 GW, and 35 ± 2 €/MWh at 8 GW (Fig. 7). On average, the modelled Norwegian prices are reduced by 0.39 ± 0.09 €/MWh/GW in relation to installed offshore wind. The variation between two simulations with equal Monte Carlo input parameters showed a somewhat higher price effect, where the reduction in prices is estimated to be 0.14–7.4 €/MWh/GW depending on changes in other system parameters. The model results also show that offshore wind contributes to reducing variation in hourly prices within a year (Fig. 8). The main reason for this is that offshore wind power contributes more to price reductions during high-price hours than during low-price hours.

3.3. Impact of access to multiple markets

The results above assume a radial connection to the Norwegian power market. In the following, we extend the analysis to assess how profitability is affected by access to multiple power markets. Here, we employ five different assumptions (Fig. 3) where the offshore installations have a radial connection to (1) the Norwegian market; (2) the German market; (3) the UK market; (4) connections to several neighbouring countries, but power can only be sent from SNII; and (5) the wind power area is used as a node and may transmit electricity directly between the spot areas.

For all scenarios, we assume an investment in 3 GW offshore wind, which may produce up to 15.4 TWh/year if no curtailment is required. We allow endogenous investments in transmission lines, but this is restricted upwards to 3 GW between SNII and each spot market.

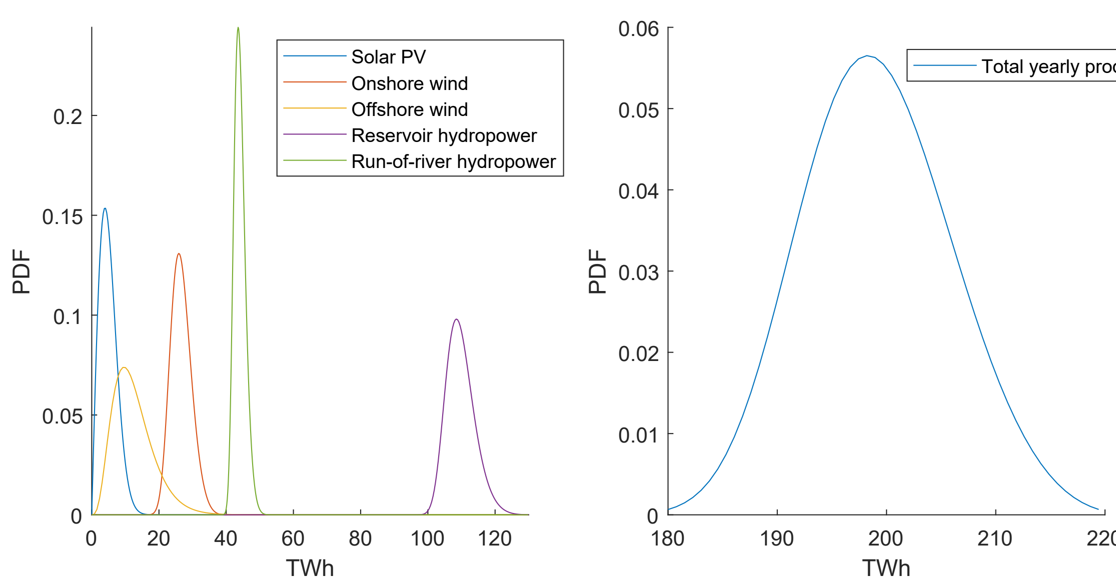

Fig. 5. Modelled range of generation levels for different technologies (left) and total production (right) in Norway.

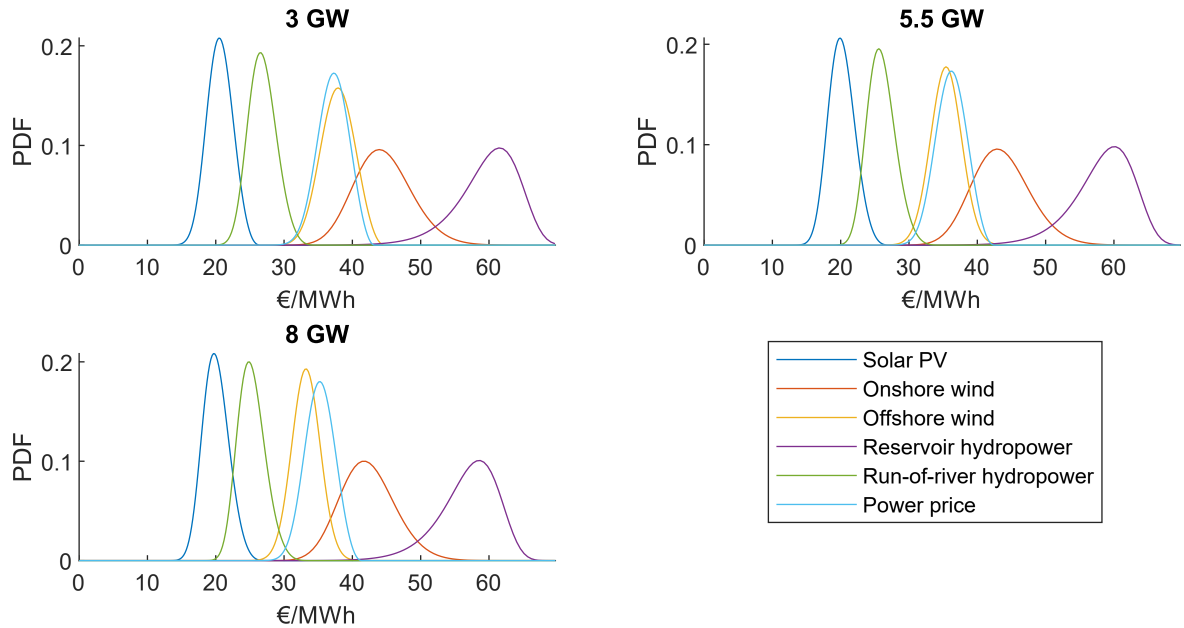

Fig. 6. Modelled market values for the main technologies in Norway for the three different scenarios.

The five different approaches produce quite different effects on the profitability of the wind field (Fig. 9). The lowest modelled market value of offshore wind is observed when there is a radial connection to Norway (30 ± 2 €/MWh). The highest value is, as expected, obtained when we allow for connection to several markets (37 ± 3 €/MWh). The highest offshore market values are obtained when the SNII site is designed as a hub where electricity can be directed in all directions (case 5 above) (39 ± 3 €/MWh). In this case, the optimal transmission line capacity increases from 3.1 GW with a radial connection to 6.5 GW as a sum of all transmission lines connected to SNII. Radial connections to the UK and Germany result in quite similar offshore wind market values of 36.7 ± 3.7 €/MWh and 37.2 ± 3.6 €/MWh, respectively, but due to different amounts of curtailment (2.4 ± 1.0 TWh in the UK and 1.5 ± 0.8 TWh in Germany), the total revenue is significantly higher when connected to the German market than the UK market (516 ± 34 million € vs. 475 ± 29 million €) (Fig. 9). The total revenue of the offshore wind site is highest when SNII is connected to several markets and lowest for a radial connection to Norway only.

The different transmission approaches for SNII have slightly different effects on the spot prices in Norway (Fig. 10). The lowest Norwegian prices are, as expected, observed when SNII is only connected to the Norwegian market (36 ± 2 €/MWh). The difference between the four other connections is relatively small, from 37.2 ± 2.0 €/MWh when the transmission is one-way (case 4) to 37.5 ± 2.1 €/MWh when SNII is used as an export hub (case 5). Correspondingly, we observe changes in the market value of the various renewable technologies in Norway (Fig. 10). However, the value of reservoir hydropower shows a slight increase as the Norwegian market becomes more integrated with the rest of Europe.

The electricity produced at SNII ends up in different markets when different approaches are used. In the radial connection scenario, where all of the electricity produced is transmitted to one country, the amount of curtailment is highest for a radial connection to the UK (2.4 ± 1.0 TWh) and lowest for a radial connection to Norway (0.4 ± 0.4 TWh). The reason for this is that periods with high wind production in the UK correlate with periods of high wind production at SNII, causing higher curtailment than when connected to Norway, which has lower amounts of wind power in the system and can utilise the flexibility of the hydropower system. As shown in Table 6, the modelled capacity between SNII and the neighbouring markets differs substantially between the cases. In case 4, transmission line investments to Denmark and Germany are profitable in 99% of the simulations and 100% when it comes to Norway, while the UK gets investments in 76% and the Netherlands in 3% of the simulations. When electricity can be transmitted both ways (case 5), a transmission line to the UK is profitable in 100% of the simulations. Transmission lines to the Netherlands are still profitable in quite a few of the scenarios (21%). A connection from SNII to Denmark appears less appealing when multiple countries can be linked in a both-way approach. Offshore wind production at SNII and the UK correlates to a large extent. This results in increased investments in the UK in the both-way scenario, resulting in the transmission line being more used to balance the UK system than to sell power produced in SNII. This is the opposite of what was found in the other countries.

For the one-way transmission (case 4), around one-third of the electricity is sent to Germany (33% ± 15%), 29% ± 13% to Denmark, and 26% ± 11% to Norway, while only a small fraction is sent to the other countries. The overall numbers are the same if we allow both-way transmission (case 5), but both import and export through the lines are higher. In general, we find that investment in transmission lines directly between the countries is lowest when we allow the use of SNII for both import and export. This shows that having a hub in the North Sea connected to multiple regions reduces the overall need for other transmission lines. It must be noted that the transmission of electricity directly between spot areas is a debated topic in Norway, and it is uncertain whether the Norwegian government will permit such a system.

4. Discussion

The European Commission [46] has stated that electricity must be allowed to move freely through cross-border trade [1,46], and this may make the scenario involving one-way transmission of electricity from SNII difficult or even impossible to implement without further regulatory amendments. However, it remains an interesting scenario since it is the case that is both economically attractive and politically acceptable in Norway. The other SNII approaches are plausible from a regulatory perspective, but as this study shows, it may be difficult to make SNII profitable if it is only connected to Norway. It may instead be more profitable to have a radial connection to Germany or the UK.

This study only focuses on the profitability of offshore investments in SNII, and as expected, we find the highest profitability if the SNII site is connected to several markets. In Norway, all cross-border transmission

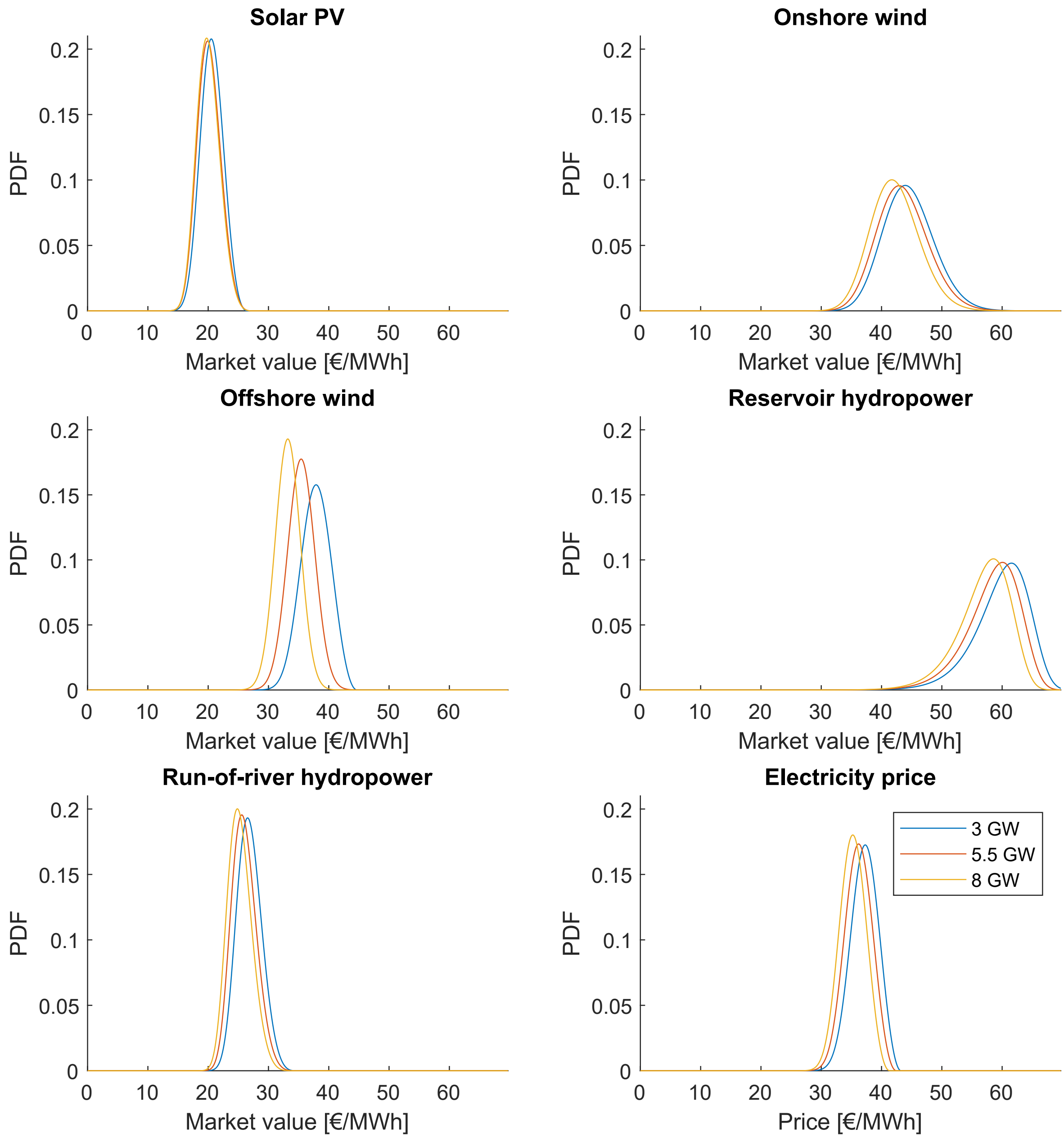

Fig. 7. Modelled yearly average market values for different energy variables in Norway at different offshore investment levels.

lines are currently owned by the TSO (Statnett). If this will also be the case for SNII, the wind park will only sell electricity to one price area. This would imply lower revenues to the offshore wind installations, but higher bottleneck revenues to the TSO. This could result in regulatory difficulties that may be overcome with an appropriate cost revenue sharing between the owners of the wind park and the transmission line.

Results from this study clearly show that the profitability of offshore wind is questionable, especially if a radial connection to Norway is chosen. Offshore wind will reduce electricity prices in Norway, which may spur investments in new power-intensive industries in the low-price regions of the country. However, such long-term demand-side dynamics have not been addressed in this study. If instead the offshore wind installations were connected to other markets, the impact on the Norwegian market would be minor, while the profitability of offshore wind would increase significantly.

According to the model results, the annual long-term average power price in Norway will linger between (30–42 €/MWh) in an average weather year. Although the annual average and median prices are within the same range independent of the offshore wind power approaches, the peak prices are substantially reduced in cases with high offshore wind developments. Also, the expected price range is narrower with more wind power, i.e., a higher amount of offshore wind does not only depress the power prices but also ceteris paribus reduce the variances over a year. The model results show that the grid connection solution is important to offshore wind market values at SNII. We find that the ranges are smallest if SNII is connected radial to Norway and widest if connected radial to the UK. Hence, the grid connection configuration will not only impact the level, but also the expected range, of the offshore wind market values. The main reason for this is that the UK is expected to install a lot of offshore wind that will correlate more with SNII, but also depress the prices toward zero when the wind production is high.

This study estimates the profitability of a wind park, but it is not only techno-economic data that is important to the success of offshore wind development. Lack of social acceptance also represents an obstacle, and the lack of acceptance for onshore wind in Norway in recent years has

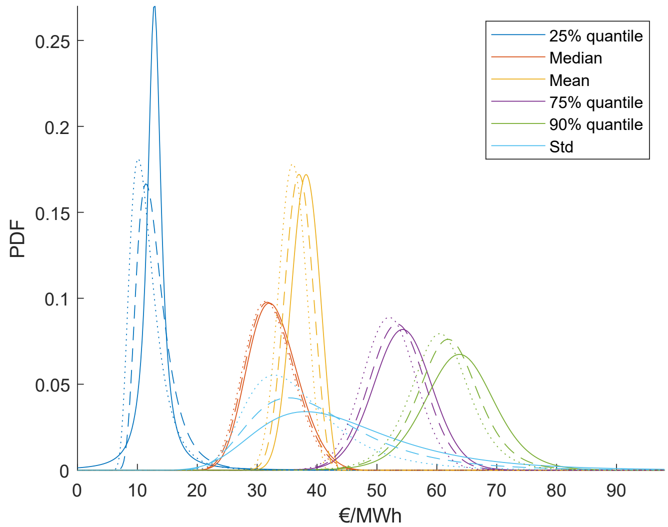

Fig. 8. Modelled mean, median, standard deviation and quantiles of the yearly price distribution in Norway. The solid line represents the 3 GW scenario, the stippled line 5.5 GW, and the dotted line 8 GW.

been a significant obstacle to onshore developments in the country [47]. Many of the same problems could arise for near-shore wind parks [48]. Factors that could reduce interest in offshore wind parks are visibility from the shore, distance to fisheries or shipping routes, or if the electricity is exported rather than used locally [48,49]. Many of these problems will be less important if the wind park is developed far from the coast, indicating that it may be easier to achieve social acceptance for wind parks such as SNII than those closer to the shore.

The study uses a Monte Carlo approach in order to cover the uncertainty of the future. As shown in Table 3, both techno-economic data, demand projections, and some generation capacities are included in the Monte Carlo simulations. When randomly selecting the Monte Carlo simulations we assume that the three groups of parameters are independent of each other, which may result in some unrealistic scenarios. For example, a scenario with high demand, high techno-economic cost, and low generation may give too high electricity prices since demand will not respond to the high prices. This effect is important to remember when interpreting the most extreme results, but since we draw 500 independent Monte Carlo simulations, we may be more certain that the average values are more realistic since it is built on few but equally many unrealistic extremes and many more likely scenarios. It is worth mentioning that most of the generation capacity is endogenously defined in the model, which will limit the effect. Also, the most extreme scenarios may be argued as possible if politicians interfere unwisely in the electricity market, for example with a price cap on the power prices.

Like other energy system modelling studies, simplifications have been made in the modelling that may have affected the results. In this study, it should be mentioned that the data is based on the meteorological year 2012, which is regarded as a normal weather year in the Nordics. For that specific year, we ensure consistency between demand profiles, inflow, and wind, but adding more weather years would probably have added additional insights. In the context of a Nordic energy system, the most extreme situations will be a dry year with cold weather and little wind during the winter versus a wet year with warm weather and much wind during the winter. Since we have used a normal weather year, we assume that the profitability found in this study is the long-time average, but real-life results of one single year may deviate significantly. The model analysis uses 288 timesteps to represent a year. Using a small number of timesteps may overestimate the system value of wind power and reduce the estimated need for backup capacity or storage. When it comes to the profitability of offshore wind, however, the value of more timesteps is less clear. Finally, the results from the endogenous modelling of offshore capacities rely heavily on the assumed LCOE costs in 2040. These LCOE assumptions are based on significant technology learning over the next twenty years and they must be regarded as highly uncertain.

5. Conclusion

This study quantifies the market effects of offshore wind production in Norway using a partial equilibrium model. Based on the assumptions made in the study we estimate that 2.8 ± 1.1 GW with an absolute maximum of 8.1 GW of offshore wind may be profitable on the Norwegian shelf without subsidies, assuming only a radial connection to the Norwegian market. The increased amount of offshore wind capacity is expected to reduce the Norwegian power prices by 0.39 ± 0.09 €/MWh for each GW of offshore wind installed. Large-scale offshore wind investments cause significant reductions in the technology's value factors. According to our results, the value factor is expected to decline from 1.02 ± 0.03 for an offshore capacity of 3 GW to 0.94 ± 0.02 if the offshore capacity is increased to 8 GW. Additional capacity in neighbouring countries would contribute to further value factor reductions.

Increased offshore wind production would primarily result in increased export from Norway, implying that offshore wind will reduce electricity prices in Norway, but not significantly change the production mix.

The economic prospects of offshore wind investment in the SNII area depend largely on the cross-border exchange solution chosen. According to the model results, a radial connection to Norway leaves the expected offshore wind market value at 30 ± 2 €/MWh. If instead a radial

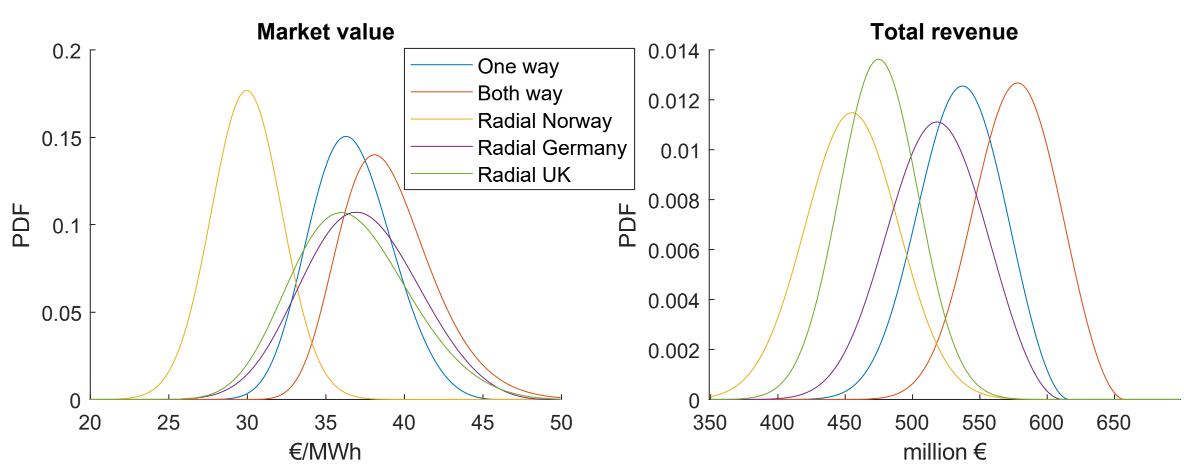

Fig. 9. Modelled market value distributions in SNII (right) and total revenue from the offshore wind installations at SNII (left) for the different scenarios.

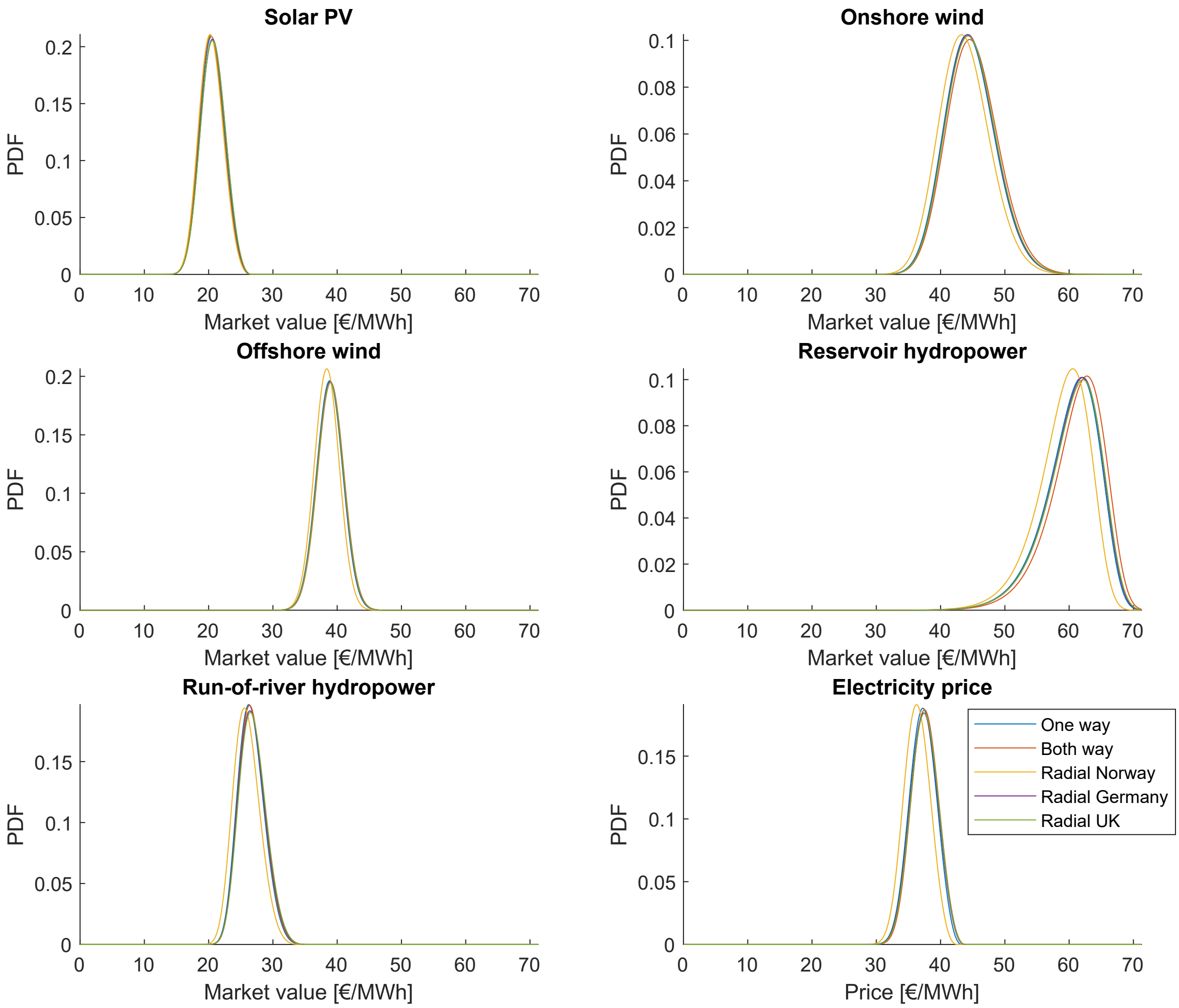

Fig. 10. Modelled market values and power price distribution in Norway for the main Norwegian technologies.

Table 6
Modelled investment in transmission lines between SNII and the different markets and the amount of energy transmitted from SNII. In case 5, electricity is exported through SNII, resulting in a higher total exchange.

		Case 1 –Radial Norway	Case 2 – Radial Germany	Case 3 – Radial UK	Case 4 – One-way	Case 5 – Both-way
Profitable investment in the share of simulations	Norway	100%			100%	100%
	Germany		100%		98%	99%
	UK			100%	76%	100%
	Denmark				99%	67%
	Netherlands				3%	21%
Average capacity [GW]	Norway	3.0			0.8 ± 0.3	2.2 ± 0.4
	Germany		3.0		1.0 ± 0.5	2.6 ± 0.5
	UK			3.0	0.6 ± 0.4	1.5 ± 0.6
	Denmark				0.9 ± 0.4	0.3 ± 0.2
	Netherlands				0.4 ± 0.4	0.3 ± 0.2
Average transmission from SNII [TWh]	Norway	15.0 ± 0.4			3.7 ± 1.6	9.2 ± 1.6
	Germany		13.8 ± 0.8		4.9 ± 2.1	14 ± 3
	UK			12.9 ± 1.0	2.2 ± 1.7	2.9 ± 1.8
	Denmark				4.3 ± 1.9	1.9 ± 1.8
	Netherlands				2.1 ± 2.1	1.0 ± 1.5

connection to the UK or Germany is chosen, the market value increases by 23%–37 ± 4 €/MWh. The total revenue is significantly higher in Germany than in the UK because of the high hourly correlations between wind power production in the UK and SNII. The highest market value is obtained if SNII is used as a transmission hub connected to several markets. A flexible grid connection to SNII would reduce the need for investments in other transmission lines in the North Sea region and flexible power generation capacity in the Northern European energy system. As such, our results indicate that choosing a transmission hub approach for the SNII area is both economically attractive and system friendly as it could contribute to balancing different markets around the North Sea.

In the following section, we give a short explanation of the main research questions. Q1 – What are the market effects of offshore wind investment in Norway?

- The main market effect of offshore wind investment in Norway is lower power prices, the estimated reduction is 0.39 ± 0.09 €/MWh for each GW of offshore wind installed. Hence offshore wind depresses the average power prices, which reduces the market values for other renewables.
- Increasing offshore wind production in Norway increases the Norwegian export, hence reducing the power prices in other countries as well.

Q2 – How much offshore wind power is it economically feasible to develop?

- Without any subsidy we estimate that between 0 GW and 8.1 GW installed capacity may be economically attractive in Norway.
- The average investment level according to our result is 2.8 ± 1.1 GW.

Q3 – What would the market value be in the case of connection to several spot markets with and without being used as a transmission hub?

- The market value of offshore wind with radial connection to Norway is 30 ± 2 €/MWh, which is also the lowest market value of all grid connections investigated.
- Highest market value is found with a hybrid connection with several markets.

Credit statement

Eirik Ogner Jåstad: Conceptualization; Data curation; Formal analysis; Investigation; Methodology; Project administration; Resources; Software; Validation; Visualization; Roles/Writing - original draft; Writing - review & editing. Torjus Folsland Bolkesjø: Conceptualization; Formal analysis; Funding acquisition; Investigation; Methodology; Supervision; Validation; Roles/Writing - original draft; Writing - review & editing.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Eirik Jåstad reports financial support was provided by Research Council of Norway through the scheme 'Enabling the green transition in Norway' [NRF-308789].

Data availability

Data will be made available on request.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.energy.2022.126594.

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