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The influence of seabed lease fees on offshore wind farm design

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ABSTRACT

Governments that control seabed generally extract fees from the offshore wind sector, often tying these fees to the characteristics of the proposed wind farms. These fees could change the optimal design of offshore wind farms, thereby affecting the long-term development of the industry. We employ microeconomic theory and incentive-response analysis to explain the effects of different types of fees on the optimal design and characteristics of offshore wind farms. We find that fees that are structured to be proportional to wind farm area, nameplate capacity, production, and revenue may influence the optimal design of a wind farm from a wind farm developer's perspective. Fees based on area, production, or revenue may result in less area used by developers. Fees based on capacity, production, or revenue may result in the choice of turbines with lower specific power, while fees based on production or revenue may additionally encourage the use of smaller turbines. All four fee types may encourage developers to use fewer turbines per wind farm. If designed intentionally, policymakers could use seabed lease fees to guide the wind farm designs toward more socioeconomically optimal outcomes, including less area used, reduced environmental impacts, or better grid integration.

1. Introduction

Offshore wind energy is a renewable power resource that is expected to play a major role in clean energy transitions (IEA, 2020). Offshore wind has already scaled up from 7.1 GW of electricity generation capacity in 2013 to 63.2 GW in 2022 (IRENA, 2023). A step change to 1 TW is needed by 2050 for the climate to stay well below the 2 °C warming target (IRENA, 2019), creating a need to substantially expand the industry. Access to offshore wind resources is generally controlled by governments, which grant offshore wind farm developers (henceforth, "developers") exclusive access to seabed for development of offshore wind farms. In recent years, offshore wind projects have been seen as economical without government subsidy in mature markets (Jansen et al., 2020), and the amount of fees paid for the right to access the seabed required to build offshore wind projects in prime locations has increased substantially (Laido and Kitzing, 2022).

When offshore wind projects require subsidies, the right to develop is often allocated to the developer that asks for the lowest level of subsidies (Netherlands Enterprise Agency, 2020a). However, if the projects are profitable without subsidy the process of obtaining seabed lease licenses can become a new point of competition. When fees are a part of the selection criteria in seabed lease auctions, they act as a tool for differentiating bidders as the seabed is allocated to the developer offering to pay the highest fees. In such auctions, developers compete with each other for access to seabed, and indirectly with other uses of seabed. Currently, offshore wind development is most economical in shallow waters near shore, within the exclusive economic zones of countries (Sørensen et al., 2021). While the total technical potential of offshore wind is great (Energistyrelsen, 2022), there can be significant conflicts with other uses for seabed in prime locations (Spijkerboer et al., 2021) and the competition is expected to increase significantly over time (Pettersen et al., 2023) which, together with the expected technological improvements in offshore wind technology (Wiser et al., 2021), may lead to further increases in the fees in the future. These fees may, however, have impacts on the design of offshore wind farms, which may shape how the industry develops. These impacts have yet to be studied.

In this paper we seek to answer whether and how the fees in seabed lease agreements affect the design of offshore wind farms. Prior literature has explored this question without describing the outcomes of fees linked to design variables (Ausubel and Cramton, 2011). The impact of subsidies has also been studied and the results suggest that fees based on production or capacity may change the optimal design of renewable energy systems (Huntington et al., 2017). We are the first to conduct an in-depth analysis of the effects of seabed lease fees on offshore wind

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farm design, as well as to explore how fees interact with other factors such as seabed usage, environmental impacts, and grid/system integration. We link the research on optimization of wind farm density (Sørensen et al., 2021), wind turbine scale (Chaviaropoulos et al., 2014), wind turbine specific power (capacity divided by rotor swept area) (Hirth and Müller, 2016; Swisher et al., 2022) and wind farm economies of scale (Junginger et al., 2020) to the standard economic theory to describe how they may be affected by fees. We provide a detailed overview of the literature used for each of the analysed actions that developers can take in response to fees (henceforth, "response modes") in Table 2.

Our methods include (1) literature review to identify the key variables that developers change in the process of wind farm optimization, (2) connecting the technoeconomic analysis of the key variables with profit maximisation theory to understand whether the incentives for changes in the optimal design are present and (3) identification and description of the offshore wind farm design mandates in seabed lease agreements (henceforth, "constraints") that interact with and change the optimization process. We address the gap in the current literature on how fees linked to the design of offshore wind farms can change their optimal design.

Our research shows that fees, the size of which is based on characteristics of offshore wind farms such as area (measured in km^2), nameplate capacity (maximum power output of the generator on the turbine measured in MW; henceforth, "capacity"), production (measured in MWh), and revenue (measured in euro), can have an impact on the optimal design of these wind farms from the perspective of the offshore wind farm developer. Fees based on area, production, or revenue can shift the optimal design of wind farms towards denser layouts that use less space. Fees based on capacity, production, or revenue can shift the optimal design of wind farms to use of turbines with lower specific power, thereby increasing production per installed capacity while reducing total production. Fees based on production or revenue could make the use of smaller turbines more profitable by reducing the advantages of larger turbines. Finally, it is possible that any of the aforementioned fees could encourage smaller wind farms as measured by the number of turbines. All of these modes may interact with constraints.

2. Methodology

2.1. Approach

The approach taken for this study comprised five distinct steps, as illustrated in Fig. 1. We started with literature review, first to identify scientific literature on seabed lease agreements, and related fields of impacts of subsidies on offshore wind farms and impacts of seabed lease fees on offshore oil and gas industries. This was followed by a review of official documents related to the offshore wind lease agreements, which gave us the categories for both fees and constraints. These categories informed the next phase, which was to match the fee categories with the offshore wind farm optimization literature. The objective was to find offshore wind optimization methods from the literature that would interact with the seabed lease fees. It resulted in the development of response modes through an iterative process. Finally, the modes were analysed together with the constraints (see Fig. 1). The novelty of this study is in categorization and combining of the fees in seabed lease agreements with the profit maximisation framework and technical literature on the design of wind farms. This enables making general inferences on how the design of projects is likely to change in response to the fees.

2.2. Framework

Consistent with standard microeconomic theory, we assume that developers choose the offshore wind farm design that maximises profits (Case et al., 2012). We investigate how the fees present in seabed lease agreements may change the optimization problem faced by the developers. We assume that developers can and will adjust the design of wind farms if the optimal design changes due to the fees. We rely on standard economic literature on profit maximisation to identify whether and how the optimal wind farm design may change due to fees. To describe each optimization problem we use the marginal approach to profit maximisation, which relies on marginal costs and revenues (Case et al., 2012). Marginal cost means the additional cost caused by adding an additional unit of the relevant variable, and marginal revenue means the additional revenue caused by adding an additional unit of the relevant variable. A profit maximising optimum is reached when marginal cost is equal to marginal revenue, from which point on adding additional units will always bring more costs than revenue (Case et al., 2012).

Similarly to private economic analysis, there are optimal designs of wind farms from a socio-economic perspective, which may be different from the private economic optima for any design variable. These can arise due to externalities, meaning costs or benefits that are not internalized in the private economic calculation. This would give rise to deadweight losses, which are a net loss to the society arising from over- or underproduction (Case et al., 2012). A seabed lease fee, if it affects the design of offshore wind farms, could be used to reduce deadweight losses through economic incentives. This is different from constraints which mandate that the design of the wind farm stay within set limits.

In our context of the offshore wind sector, we observe, for example, that the seabed has many uses other than for offshore wind farms such as fishing, shipping and biodiversity conservation, which may be impacted

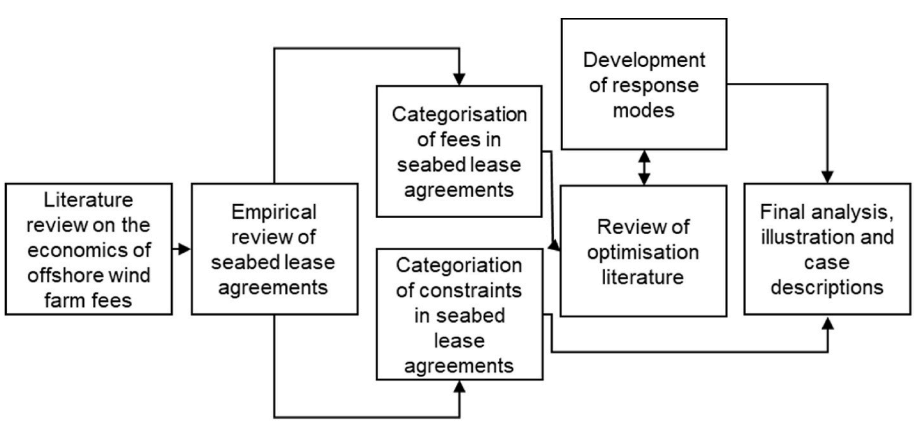

Fig. 1. Overview of the approach. The literature review and empirical review of seabed lease agreements lead to both categorization of fees and constraints. While the constraints were directly carried over to the final analysis, the fees fed into an iterative process of optimization literature search and the description and refining of the response mode categories. Eventually, the modes and the constraints were used for the final analysis.

by the design of offshore wind farms (EWEA et al., 2012; Gray et al., 2016; Masden et al., 2012). Additionally, offshore wind farm design can also affect its impacts on the grid as discussed in section 3.2. If the private economic analysis by developers does not account for these effects, there may be a misalignment between private economic and socio-economic analysis. We explore how fees could be used in a similar way as constraints to enable beneficial socio-economic outcomes. We analyse how fees and constraints interact with the aim to enable future analysis of impacts and socioeconomic optimization.

2.3. Identification and categorization

We investigate all jurisdictions bordering the North Atlantic Ocean that have held auctions for offshore wind seabed lease allocation only, as opposed to auctions that combine seabed lease allocation with subsidy allocation: the United States of America (US), the Netherlands, England, Wales and Northern Ireland (ENG,WLS,NIR), and Scotland, starting from year 2013. We do not consider non-competitively allocated projects, scientific research projects, and seabed allocated solely for cables. We identify fees that are linked to design elements by investigating the equations that are used to calculate the fees as presented in the seabed lease documents. We categorize the fees based on the design elements of offshore wind farms in these equations that the developers can influence. If a fee depends on multiple factors that the developers can influence, we categorize the fee as the product of these variables. For the purposes of categorization, we define production as the product of capacity and capacity factors and revenue as the product of production and electricity price. The developers can influence the value of all of these variables through wind farm design changes, with relevant explanations provided in the results section 3.2.

We have identified four fee variables that are related to design elements that developers can influence to change how much they have to pay in fees for which there is enough optimization literature to analyse. These are the total area of the wind farm, the total capacity of the wind farm, the total production of the wind farm, and the revenue of the wind farm. The area-based fees also have a small subcategory for fees targeting the cable corridor. We then create five fee categories. The first four are for the four design elements: area (km^2), capacity (MW), production (MWh), and revenue (€). Fees which the developers cannot influence through design changes are categorized as lump sum payments. This includes fees which rely on hypothetical as opposed to wind farms proposed by developers for calculations.

If developers are free to optimize the offshore wind farm, they can directly influence the area of the wind farm by making choices regarding the locations and the number of wind turbines, and the total capacity of the wind farm, by making choices regarding both the number and capacity of turbines. Developers can, therefore, directly influence the size of any fee that is paid per km^2 of seabed or per MW of installed capacity through their design choices. Since these and other design related decisions indirectly affect the amount of production and revenue that the wind farm generates, the developers are in control of the size of fees that relate to those variables. Of course, the developers may also be able to influence the size of the fees by changing their bids if these are not administratively fixed.

This leaves two additional elements, which are not analysed in depth in this paper: lump sum payments and time related variables. Lump sum payments are fees that are not directly linked to any design element of the offshore wind farm. While they may indirectly influence the overall set-up and attractiveness of wind farms, these fees cannot be influenced through changes in wind farm design. Hence, they are not analysed in this paper.

Time related variables can be split into those related to the development, production or decommissioning phases wherein the longer a wind farm is in one of these phases, the greater the fees related to that phase. Fees per unit of time in any of these categories could be expected to incentivize the shortening of these phases as it would reduce the payable fees. The choices made in response to the incentive to shorten each of these phases could have indirect impacts for the wind farm design similarly to how the fees may impact operations and maintenance setups, which may in turn impact the design. We could not, however, find literature that pertains to these particular topics. Hence, these fee elements are not covered in this paper.

2.4. Incentive response analysis

The response of the firms to the fees depends on how the fees impact their marginal cost and marginal revenue curves. We determine the expected impact of the fee on optimal design by comparing the marginal cost and marginal revenue curves with and without the fee. A fee that is constant in relation to the optimized variable is depicted as shifting the marginal cost curve upward. Fees may also change the shape of the marginal cost curve. For the fees that we analyse, this happens when the fee is dependent on the marginal revenue curve and is, therefore, not constant in relation to the optimized variable. We describe the likely shapes of the marginal cost and marginal revenue curves and provide some illustrations. We use smooth representations of marginal cost and marginal revenue curves for simplicity. However, offshore wind farms are likely to have more complex marginal cost and marginal revenue curves, which means that the general inferences need to be put in local context.

In the field of energy economics, achieving the lowest levelized cost of electricity is often set as a target for optimization (González-Longatt et al., 2012). Levelized cost of electricity shows the average cost of producing a MWh of power discounted to present terms. However, as we rely on the difference between costs and revenue, we deem it to be a poor tool for our purposes.

Developers could take different actions to respond to the different fees. We call these actions response modes. We have conducted a literature search for each of the different categories of fees to find the relevant literature on optimization. This resulted in a selection of response modes enabling us to connect different optimization literature to the fees. The response modes are as follows: changing the area of the wind farm, changing the number of turbines, changing the capacity of individual turbines, and changing the specific power of turbines.

This process expands the analysis beyond a purely theoretical context into the field of project optimization allowing deeper discussion of the implications of the fees, which is relevant in the policy making context. While each of the types of fees could have a cascading impact on different optimization processes throughout the entire supply chain and at any level of detail, we focus on the first order impacts in the design phase of offshore wind farms. This process will not have resulted in a comprehensive overview of all the responses that the developers could take, especially when one considers the high number of components that make up turbines, each of which could be optimized individually or in combination with other components in response to the fees. We also do not cover the operations and maintenance or project management related topics. However, our approach enables us to cover the major design phase elements of holistic optimization approaches such as described in (Cortizo et al., 2019; Réthoré et al., 2011).

2.5. Case descriptions

We collected data on projects from the four jurisdictions studied in in this paper, summarized in Table 1, 4 and 5. The objective is to show what some plausible values for the variables of interest are by showing the averages of past projects. The criteria for inclusion are the same as for the investigation of seabed lease documentation described in section 2.3. We included projects in the dataset that are from one of the four jurisdictions and have been allocated no earlier than 2013 to enable the analysis of current practices. It is important to note that this choice limits the available data as seabed lease agreements are signed relatively early in the process of developing offshore wind farms.

Table 1
Overview of project data availability. The area of the offshore wind farms is always described during the lease allocation. The capacity is often described during the lease allocation, though the final installed capacity may differ from the initial proposals. Details about the turbine choice can only be confirmed for projects that have made significant progress towards operation start.

Country	Number of projects	Area data availability	Proposed capacity data availability	Turbine number data availability	Specific power data availability	Turbine capacity data availability
ENG,WLS, NIR	6	100%	100%	17%	0%	17%
Scotland	17	100%	100%	0%	0%	0%
US	30	100%	83%	23%	27%	27%
Netherlands	5	100%	100%	60%	60%	60%

We only consider projects that have not received subsidies within the seabed lease allocation process as these may interfere with fees due to their opposite nature. We briefly discuss the potential interaction of fees and subsidies in the discussion section. We also did not consider non-competitively allocated projects, scientific research projects, and seabed allocated solely for cables. The dataset, therefore, consists of projects allocated in the Seabed Lease Allocation Round 4 in ENG,WLS, NIR and the ScotWind allocation round in Scotland; the Dutch projects allocated starting from the first subsidy free projects Hollandse Kust (Zuid) Wind Farm Zone, Sites I and II tendered in 2018; and most US seabed leases allocated starting from 2013. In cases where the seabed lease area changed shape or size, or was split or merged, we included the latest versions of the projects in the dataset.

We prioritized data published by the responsible national authorities. If these did not provide the necessary details by providing a range of values or if no official data was available, we searched the corporate webpages of the developers or original equipment manufacturers that were involved in the projects for the exact value in that range. When there was disagreement between the sources, we used the official data. If at the end of this process we still had a range of estimates, we entered the arithmetic mid-point of the range. Extreme values such as minimums and maximums were excluded. In cases where both the minimum and maximum were available, they were treated as ranges and the arithmetic mid-point was entered. The data is up to date as of October 31, 2023.

3. Results

3.1. Categorization of fees

Table 2 presents our categorization and descriptions of the fees. There is no standard naming convention for the types of fees, which results in similar fees having different names and fees that are different carrying the same name. In total, we have described 15 fees, which we have allocated into five categories. Of these, three were area-based, three were capacity-based, four were production-based, one was revenue-based, and six were simple cash payments. Some of the fees are in multiple categories as different versions of the same fee are applicable under different circumstances.

3.2. Response modes

We identified four relevant response modes summarized in Table 3 along with the fees that may affect them and references to their respective fields of optimization research and relevant literature. We will describe these modes individually in sections 3.2.1 to 3.2.4. Each response mode represents one-way developers can adjust wind farm design to change the magnitude of one or more seabed lease fees. In order to separate the specific effects of the fees, each response mode should be interpreted as changing only the variable in question, all else equal. However, as keeping all other variables constant is generally not possible, we have marked the exceptions in parentheses keeping our definitions close to how they are used in the literature. Additional possible response modes, not backed by scientific literature, are described in section 3.2.5.

3.2.1. Wind farm area

Offshore wind farms can cover a large area of seabed, which is a limited resource in the most profitable locations. The competition for space by offshore wind farms is expected to intensify in the coming decades (Pettersen et al., 2023). The use of seabed for wind farms can also exclude other users. Introducing fees that increase with the amount of area covered by the wind farm could reduce the optimal spacing between turbines, thereby leaving more of the seabed for other users.

A fee per km^2 would shift the cost curve upward by a fixed amount as each additional km^2 would carry this cost, reducing the optimal wind-farm area (see Fig. 2). The shape of the marginal revenue and marginal cost curve in the relevant range (where optima can be found) and the size and shape of the fee induced shift determine the size of the impact of this and other response modes. The more variation due to the wind resource, soil conditions or water depth within the wind farm area in the relevant range, the less impact the fee would have as it would make the marginal cost curve steeper (see Fig. 3).

Unlike the area-based fee, a production- or revenue-based fee would diminish as it only affects the size of the fee through the wake effect on production (see Fig. 2). A fee per MW would not have an impact in this setting as it would be constant. The area and installed capacity of wind farms has a high degree of variation, showing a large potential for changes for this variable (see Table 4 and Fig. 4) (see Fig. 5).

To construct these figures, starting with the cost curve, increases in seabed depth and distance to shore tend to make offshore wind farms more costly (Sørensen et al., 2021). Additionally, some seabed conditions are more costly to develop than others, and cabling costs are lower for dense wind farms (Cortizo et al., 2019; Sørensen et al., 2021). The wind resource can vary within wind sites and between sites affecting revenues (Cortizo et al., 2019). Only considering these factors would mean wind turbines should be installed in dense formations near shore and in shallow waters with the best soil and wind conditions. However, installing turbines in dense formations increases the wake effect, which reduces production (González-Longatt et al., 2012) as well as causing a rise in operations and maintenance costs due to additional fatigue (Réthoré et al., 2011).

As the spacing between wind turbines is increased, the output initially increases rapidly due to the reduced wake effect. However, as the spacing is increased further, the positive effect from decreasing the wake effect diminishes, approaching zero. If there is significant variation in depth of seabed or wind resource within the project area and assuming most favourable seabed is developed first, expanding the wind farm would, eventually, using more unfavourable seabed. These effects coupled with the cabling costs raise the marginal cost curve so that an optimum is created.

Projects can vary significantly in terms of their size, capacity and density with different jurisdictions affording varying levels of control to the developers over these variables. For this project we have defined the area change mode as keeping everything else constant. The area of wind farms can also change due to the number of turbines, however. When comparing projects it is, therefore, important to also look at the density of said wind farms (see Table 4).

Table 2
Overview of fees in offshore lease agreements (excludes fees for submitting applications).

Jurisdiction	Official name	Category	Description	Wind farm design variable that the developers can change to change the size of the fee
ENG,WLS, NIR	Option fee	Fee per MW	Fee per MW per year before operation (The Crown Estate, 2019); Fee size based on bids and is decision criterion for ranking bids (additional 1£ added for cable corridor) (The Crown Estate, 2019).	Capacity (can also adjust bid)
ENG,WLS, NIR	Rent before operation	Fee per MW or MWh	Fee based on lower of a fixed rate of £0.9 per 80% of expected annual production in MWh as agreed with Crown Estate (base rent) or the annual option fee paid annually before operation (The Crown Estate, 2019).	Production or capacity
ENG,WLS, NIR	Rent during operation	Fee per MWh or revenue	Fee is the highest of the base rent, 2% of revenue, or 2% of average project revenue per MWh at 80% of expected annual production in MWh in preceding two years paid annually during operation (The Crown Estate, 2019).	Production or revenue
Scotland	Option fee	Fee per km^2	One-time fee per square kilometre with minimum of £2000 per km^2 and maximum of £100,000 per km^2 with the amount determined through bidding (Crown Estate Scotland, 2021a). Wind farms up to 860 km^2 (Crown Estate Scotland, 2021b).	Area (can also adjust bid)
Scotland	Rent	Fee per MWh	Fee paid quarterly at a fixed rate of £1.07 per MWh (Crown Estate Scotland, 2020).	Production
US	Option fee	Simple cash payment	Fee determined through bidding for lease area (BOEM, 2019). Newer lease agreements may be direct some towards building the offshore wind supply chain in the US (BOEM, 2022a).	None (can adjust bid)
US	Rent	Fee per km^2	\$3 per acre fee paid before operation (BOEM, 2019). Areas are predetermined for the official auction, though developers may sell the rights to whole or part of wind farm area on secondary markets (BOEM, 2018).	Wind farm area
US	Operating fee (first seven years of operation)	Fee per MW	Fee based on 2% of prevailing electricity prices for first seven years (or 1% for 5 years if the project qualifies for a supply chain incentive available in some agreements (BOEM, 2022b)), capacity and assumed capacity factor of 40% (BOEM, 2022c).	Capacity
US	Operating fee (subsequent years of operation)	Fee per MWh	Fee based on 2%, prevailing electricity prices, capacity and the capacity factor calculated based on the 5 years leading up to the payment period starting from the eighth year (BOEM, 2019).	Capacity and capacity factors (which together make up production)
US	Rent (for the cable corridor)	Fee per km^2 (of cable corridor)	Fee paid annually at a rate of \$5 per acre landing cable corridor with a width of 200 or a minimum of \$450 per year, with additional space priced at \$5 per acre (BOEM, 2019).	Area (only for the cable corridor)
Netherlands	Rental price for infield cables	Simple cash payment	Fee with a predetermined cost per m^2, cable corridor width and length (Netherlands Enterprise Agency, 2020a). Depends	None

(continued on next page)

Table 2 (*continued*)

Jurisdiction	Official name	Category	Description	Wind farm design variable that the developers can change to change the size of the fee
			on the relative proportion of the wind farm that is within a 12 nautical mile zone from as measured from the coast (Netherlands Enterprise Agency, 2020a).	
Netherlands	Reservation fee	Simple cash payment	Fee that depends on the area of the wind farm within the 12 nm zone with a predetermined rate of €650 per MW annually applying before commissioning and during decommissioning (Netherlands Enterprise Agency, 2020a).	None
Netherlands	Operating fee	Simple cash payment	Fee paid at €0.98 per MWh with an assumed capacity per wind farm of 4000 full load hours per year irrespective of actual production (Netherlands Enterprise Agency, 2020a).	None
Netherlands	Financial bid	Simple cash payment	Fee is part of a multicriteria auction wherein bidders get 1 point for every M€2.5 up to a maximum of M€50 offered (De Minister voor Klimaat en Energie, 2022).	None (can adjust bid)
Netherlands	Cost reimbursement	Simple cash payment	Fee covers costs related to analysis and decision making for the choice of seabed area (De Minister voor Klimaat en Energie, 2021).	None

3.2.2. Number of turbines

The number of turbines per project varies greatly between jurisdictions (see Table 5). Changing the number of turbines on a wind farm results in a linear change in MW and km^2 assuming the expansion keeps the wind farm density constant. The change in production created by the expansion would also affect production- and revenue-based fees, though non-linearly. These fees may reduce the optimal number of turbines. However, unlike in the case of changes in distances between turbines where the benefit of ever greater distances between turbines approaches zero, the additional production from adding new turbines without increasing density is unlikely to decline to zero within the range relevant for single wind farms.

On the figures, capacity- and area-based fees shift the marginal cost curve upward uniformly, while production- and revenue-based fees have an impact that diminishes with the decline in revenue. This shape is determined through multiple factors, most notably as adding more turbines decreases the revenue per turbine due to the wake effect at a declining rate per turbine (González-Longatt et al., 2012). If the developer were to increase the number of turbines, it is likely that they would

Table 3

Response modes and associated fees. Overview of the modes wind farm developers can use to change the value of the variables based on which fees are paid. We list the four response modes that have been investigated in detail in the upcoming subsections, the fees that they are impacted by, and the literature that we used.

Response mode	Fee variable	Field of optimization and relevant literature
Wind farm area (keeping number of turbines constant while varying wind farm density)	km^2, MWh, euro of revenue	Wind farm density optimization (González-Longatt et al., 2012; Lackner and Elkinton, 2007; Sørensen et al., 2021)
Number of turbines (keeping wind farm density constant while varying wind farm area)	km^2, MW, MWh, euro of revenue	General wind turbine characteristics (Energistyrelsen and Energinet, 2022), economies of scale in offshore wind (Dismukes and Upton, 2015; Ederer, 2015; Junginger et al., 2020; Möller et al., 2012; Morthorst and Kitzing, 2016), overplanting (Wolter et al., 2020)
Turbine scale (keeping the wind farm capacity constant while varying the number of turbines)	MWh, euro of revenue	Turbine scaling (Chaviaropoulos et al., 2014)
Turbine specific power (keeping the number of turbines constant while varying wind farm capacity)	MW, MWh, euro of revenue	General wind turbine characteristics (Energistyrelsen and Energinet, 2022), wind turbine specific power optimization (Hirth and Müller, 2016; Swisher et al., 2022), wind turbine specific power optimization and interaction with subsidies (May 2017), turbine component scaling (Chaviaropoulos et al., 2014)

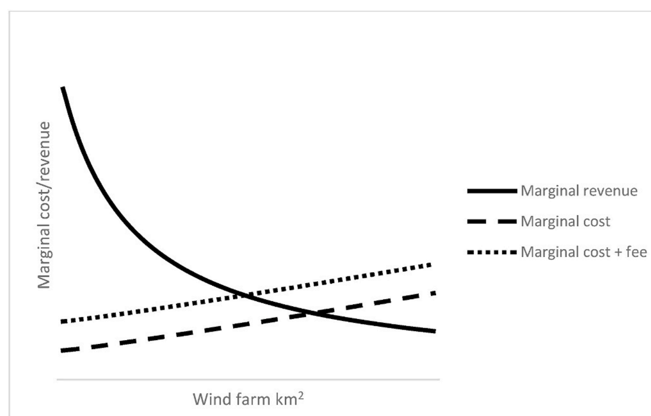

Fig. 2. Optimizing the area of a wind farm. Lowering the density of the wind farm increases the production due to a decline in the wake effect, though at a decreasing rate. The cost increases due to increased cabling costs and the utilization of less favourable seabed. Adding a fee per km^2 to an offshore wind farm shifts the marginal cost curve upward uniformly, creating a new optimum with a smaller wind farm. The effect for a given fee size is greater the further to along the initial optimum was given the diminishing nature of wake effects as the primary driver of the marginal revenue curve.

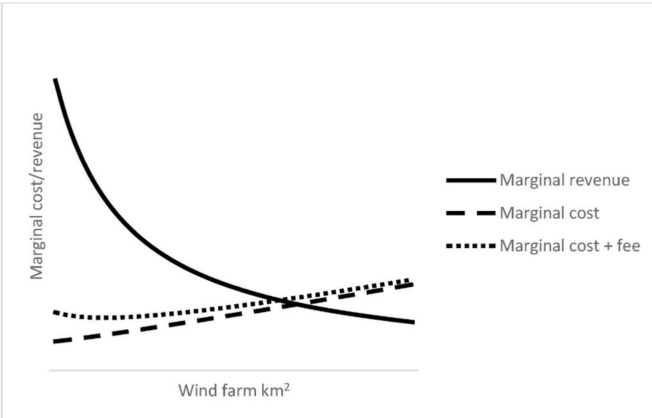

Fig. 3. Optimizing the area of a wind farm. Lowering the density of the wind farm increases the production due to a decline in the wake effect, though at a decreasing rate. The cost increases due to increased cabling costs and the utilization of less favourable seabed. Adding a fee per euro or MWh to an offshore wind farm shifts the marginal cost curve up proportionally to the marginal revenue curve, creating a new optimum with a smaller wind farm. As the marginal revenue curve trends nearer to zero the gap between the marginal cost and marginal cost + fee curves narrows.

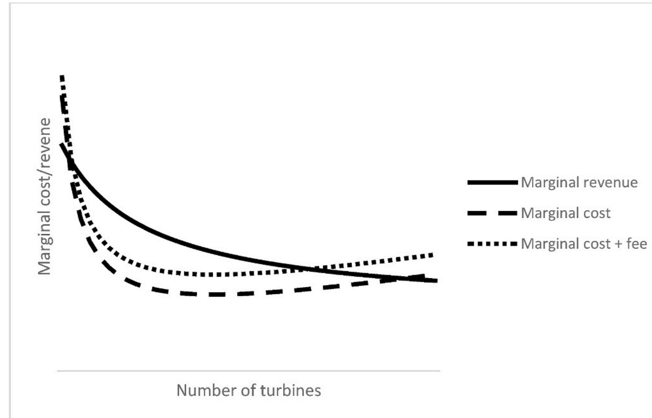

Fig. 5. Optimizing the number of turbines. Proportionately increasing the area and the number of turbines increases production, though at a rate that declines fast initially due to wake effects. The costs decline fast as fixed costs and other process optimizations are associated with the first turbines. The costs start increasing again as the wind farm expands into less favourable areas. Adding a fee per km^2 or MW to an offshore wind farm shifts the marginal cost curve up uniformly, creating a new optimum.

Table 4
Shows the expected densities of recent offshore wind projects in each of the jurisdictions. The data includes projects from the Seabed Lease Allocation Round 4 allocation auction held in 2021 for ENG,WLS,NIR, the ScotWind allocation auction held in 2022 for Scotland, the allocation auctions starting from the first subsidy free projects Hollandse Kust (Zuid) Wind Farm Zone, Sites I and II held in 2018 for the Netherlands, and all commercial offshore wind allocation auctions held starting from 2013.

Country	Average area (km^2)	Proposed capacity (MW)	Average density (MW/km^2)
ENG,WLS, NIR	406	1330	3.4
Scotland	432	1460	3.8
US	343	1871	5.3
Netherlands	112	747	6.9

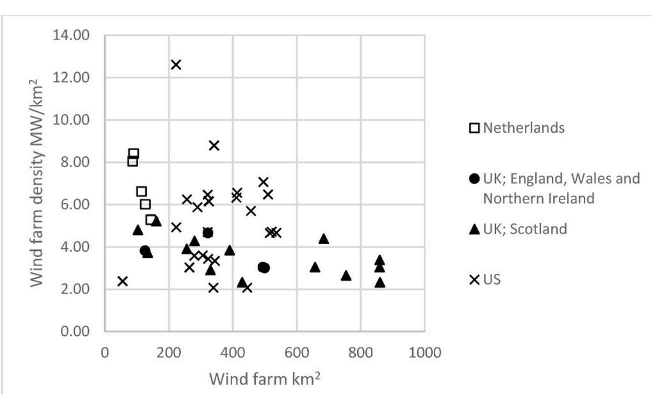

Fig. 4. Shows the density of offshore wind projects according to their expected capacities from seabed lease allocation rounds present in the dataset.

Table 5
The other characteristics of offshore wind farm projects. These are the datapoints of interest for sections 3.2.2 to 3.2.4. Note that very little data is available, so the data is necessarily skewed towards older proposed projects as they are more likely to have settled on the final design.

Country	Average number of turbines per project	Average turbine capacity	Average specific power of turbines
ENG,WLS, NIR	30.0	18.0	No Data
Scotland	No data	No Data	No Data
US	94.0	12.9	345
Netherlands	69.3	11.0	367

choose to expand in the most profitable areas and vice versa for reductions in the number of turbines, implying a raising marginal cost curve.

An important factor to consider is economies of scale (i.e., larger projects have lower average costs). The decline in levelized cost of electricity for larger wind farms implies that at least the average cost of wind farms declines as the turbine number increases (Energistyrelsen and Energinet, 2022; Junginger et al., 2020; Morthorst and Kitzing, 2016), though some caution needs to be taken with these figures as some of the literature on offshore wind farms disputes these findings (Dismukes and Upton, 2015). While it is clear that increasing the number of turbines leads to an initially sharp drop in marginal costs due to the spreading of fixed costs over more turbines (Cortizo et al., 2019) it is less clear what the full shape of the marginal cost curve for individual project would be.

In standard economic theory, marginal costs are often thought to decline as production increases, reaching their minimum, beyond which they increase again (Case et al., 2012). Whether the marginal cost starts increasing for real offshore wind farms is likely heavily dependent on project specific constraints, the seabed conditions and existing infrastructure among other factors. We have chosen to depict illustrative cases where the marginal cost increases due to the deterioration of seabed conditions, creating an optimum. However, if the marginal revenue were higher than marginal cost for the entire relevant range, the optimal offshore wind farm size would be the largest possible considering some non-economic constraint, for example maximum number of turbines, and the fees would have no effect on optimal design. This may be the case for some projects discussed in the constraints section.

The ability of the fees to affect the optimal number of turbines also depends on the elasticities of marginal revenue and marginal cost in the relevant range. The steeper the marginal cost and marginal revenue curves at the crossover point, the less of an impact the fee would have. In practice the marginal cost curve in this response mode is likely volatile as adding more turbines may sometimes require large adjustments to the wind farm, such as new offshore substations or onshore grid upgrades. If the optimal wind farm design is reached at one of those points that trigger a major cost increase, the fee is unlikely to have an impact on the optimal number of turbines as the marginal cost curve would be vertical (see Fig. 7). However, if there are multiple such cost spikes along the marginal cost curve, the fee may make the optimum jump from one cost spike to another (see Fig. 6).

Overplanting is an exceptional case where there could be a significant change in revenues as the number of turbines changes. Overplanting refers to the installation of turbines so that the capacity of the wind farm exceeds the maximum capacity of the transmission cable (Wolter et al., 2020). The profitability of overplanting depends on the trade-off between marginal revenue which declines relatively steeply, and additional costs with a relatively stable marginal cost (Wolter et al., 2020). Fees per MW, assuming they are scaled to the capacity of the wind farm as opposed to the cable capacity, and per km^2 would likely reduce the optimal number of overplanted turbines, while the effects per MWh and per revenue fees would decline proportionally to the marginal revenue curve. If the fees are proportional to the cable capacity the capacity-based fees would not have an effect.

3.2.3. *Capacity*

The average offshore wind turbine has become larger (IRENA, 2022). Changing the size of wind turbines requires changing many design elements simultaneously. Innovations in some components or processes can create new optima for other components and processes. With improvements in turbine technology the optimal size of offshore wind turbines can change. The most impactful changes in turbine scaling often happen on the cost side (Chaviaropoulos et al., 2014), which does not directly interact with the fees in seabed leases. However, scaling has also improved production (IRENA, 2022), which interacts with fees directly as the fees can limit the potential upsides of larger turbines.

As wind turbine developers seek to optimize their wind farm, they are constrained by the technologies available at the time. It is not straight forward to define scaling in this context as different parts of turbine technology may improve at different speeds, if at all. For our purposes we define it as a change in the capacity followed by a full turbine and system optimization, though leaving the wind farm capacity constant. This necessarily means that the number of turbines per wind farm declines.

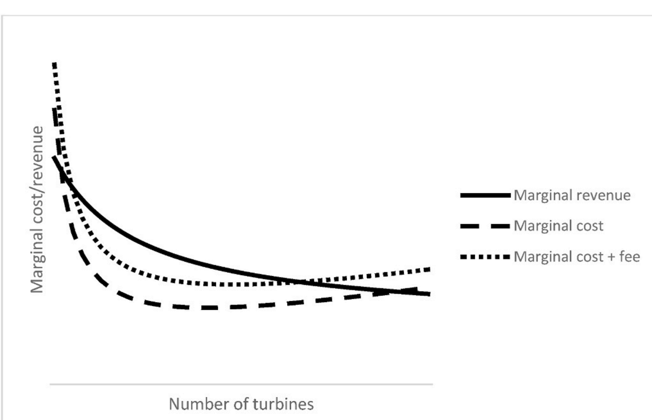

Fig. 6. Optimizing the number of turbines. Proportionately increasing the area and the number of turbines increases production, though at a rate that declines fast initially due to wake effects. The costs decline fast as fixed costs and other process optimizations are associated with the first turbines. The costs start increasing again as the wind farm expands into less favourable areas. Adding a fee per unit of revenue or MWh to an offshore wind farm shifts the marginal cost curve up proportionally to the marginal revenue curve. As the marginal revenue curve declines, the gap between the marginal cost and marginal cost + fee curves narrows.

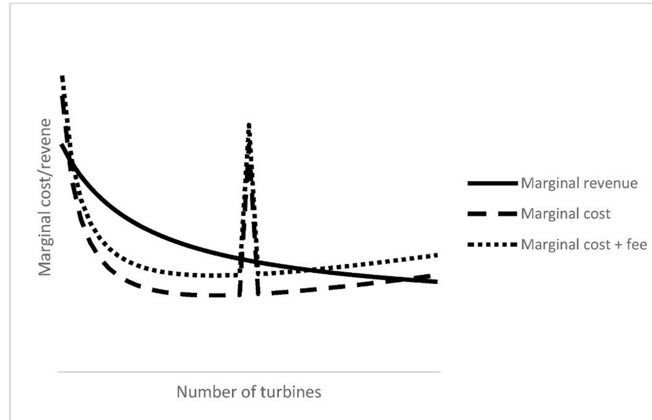

Fig. 7. Optimizing the number of turbines. Proportionately increasing the area and the number of turbines increases production, though at a rate that declines fast initially due to wake effects. The costs decline fast as fixed costs and other process optimizations are associated with the first turbines. The costs start increasing again as the wind farm expands into less favourable areas. Adding a fee per km^2 or MW to an offshore wind farm with a cost spike shifts the marginal cost curve up uniformly, creating a new optimum. However, due to the cost spike creating a vertical marginal cost curve at the point of optimum, the optimal number of turbines does not change.

According to work done in the past on multidisciplinary design optimization of offshore wind turbines, on the assumption that technological improvements would continue, the optimal turbines were expected to be larger and more expensive, have lower economies of scale due to the need for fewer turbines, though with the benefit of lower balance of plant and operations and maintenance costs, and, crucially for our analysis, an improved capacity factor (Chaviaropoulos et al., 2014). Some of this improvement was expected to occur as larger turbines were expected to have lower specific power at the new optimum, which we will also cover in the next section. The additional factors include a reduction in the wake effect as fewer turbines are needed to reach the same capacity (Chaviaropoulos et al., 2014).

Scaling using the assumptions of constant density, capacity and size would not lead to changes in terms of area- and capacity-based fees. However, due to a change in production there would be an impact on production- and revenue-based fees as the marginal revenue curve is expected to decline as larger turbines provide higher capacity factors, though at a decreasing rate (Chaviaropoulos et al., 2014). The marginal cost curve, however, is expected to initially decline steeply as the total fixed turbine costs are reduced with the decline in the number of turbines, the effect of which is eventually outweighed by the exponentially increasing costs of different components (Chaviaropoulos et al., 2014). As the fees reduce the benefit of larger turbines, they are likely to incentivize the use of smaller turbines if the developers have a choice. However, as the production change is likely to be a minor contributor to the optimal design as compared to the changes on the cost side, the impact of the fees is unlikely to be large (see Fig. 8). If there were a fee that were based on the size of each individual turbine in the wind farm, it would shift the marginal cost curve upward uniformly. However, there is no such fee among the jurisdictions that were investigated in this study (see Fig. 9).

As the industry is still developing and the rescaling of turbines is continuing, the size of the turbines is likely heavily dependent on when the projects are built. This drives much of the data uncertainty for capturing the expected scale of turbines for projects that are in development. The turbine choice is often confirmed later than the area or even the total capacity of the wind farm (see Table 5).

3.2.4. *Specific power*

Specific power refers to the ratio between the swept area of the rotor

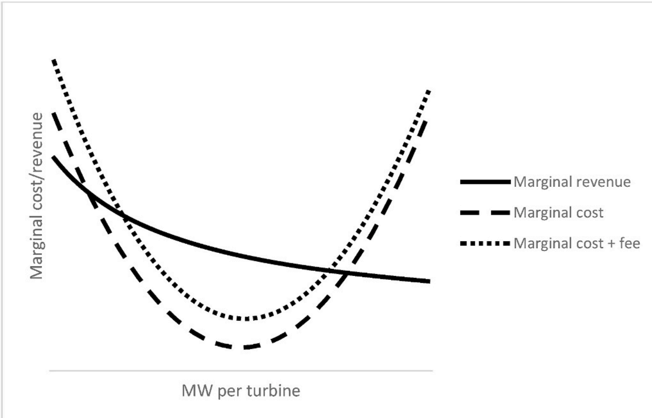

Fig. 8. Optimizing turbine scale. As the turbines are increased in scale, the overall cost of the wind farm initially declines as fewer costs that are incurred per turbine are needed due to the decline in the number of turbines. The costs start increasing when the cost increases from larger turbines start to dominate. The revenue increases due to capacity factor improvements, though at a decreasing rate. Adding a fee per unit of revenue or MWh to an offshore wind farm shifts the marginal cost curve upward proportionately to the marginal revenue curve, creating a new optimum with smaller turbines. As the marginal revenue curve declines, the gap between the marginal cost and marginal cost + fee curves narrows.

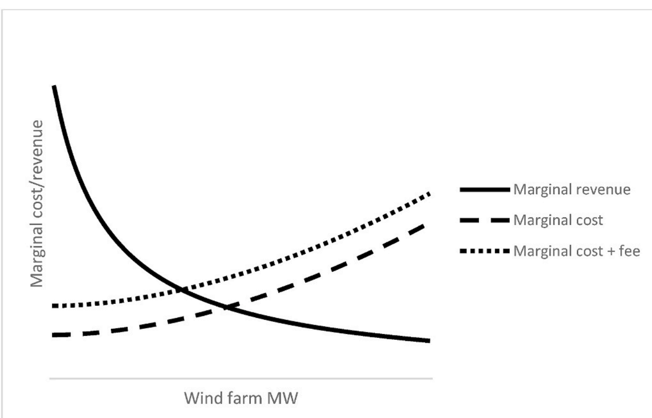

Fig. 9. Optimizing specific power. As the specific power of turbines is increased, output is increased, though at a declining rate as the wind speeds required to take advantage of greater maximum output increase and become rare. Upgrading transmission and offtake, and upscaling the generator and other necessary components leads to increasing costs. Adding a fee per MW to an offshore wind farm shifts the marginal cost curve up uniformly creating a new optimum.

(total area from which the blades capture wind energy measured in m^2), and the capacity of a wind turbine (Energistyrelsen and Energinet, 2022). The larger the swept area, the more wind that could be turned into electricity the turbine can capture. The larger the capacity of the turbines, the greater the maximum production capacity of the wind turbine. Capacity-based fees could make it more beneficial to install lower specific power turbines if the decline in revenues is outweighed by the decline in the fee and other costs. For fees based on production and revenue, the incentive transmits through its impact on production.

If a turbine is designed to take advantage of low wind speed events (a low wind turbine), it will have lower specific power than the normal turbines of the same size (Hirth and Müller, 2016; Swisher et al., 2022). From the cost perspective, different components increase in costs at different rates as the capacity increases. Most notably, as the generator determines the capacity, it needs to increase in capacity among other items. The cost of scaling most components rises exponentially as the turbine capacity is increased leading to an optimal turbine design (Chaviaropoulos et al., 2014). Additional costs beyond the turbines themselves could come from, for example, cables. If these are sized for the maximum output of the wind farm it leads to decreasing utilization and higher average cost for transmission due to a lower capacity factor (Swisher et al., 2022).

Higher specific power generally leads to lower capacity factors with the benefit of greater production during high wind speed hours (Energistyrelsen and Energinet, 2022). As turbine capacity is increased (leaving the rotor size unchanged) more power can be produced, though at a decreasing rate (assuming relevant components are adjusted). This means that less energy is produced for every marginal MW of capacity (Energistyrelsen and Energinet, 2022). The relative difference between changes in capacity and production and increases in costs leads to diminishing returns to increases in specific power. An additional factor is that electricity prices are generally lower when wind speeds are high, meaning that turbines with lower specific power are likely to have higher market value factors as they produce relatively more power when wind speeds are higher (Hirth and Müller, 2016; May 2017; Swisher et al., 2022). Similarly to the turbine capacity, the specific power of the turbines used in wind farms is revealed later than the area and size of the wind farm. In the case of specific power, to determine its value, information about either the specific turbine or a combination of both capacity and the rotor swept area is needed (see Table 5).

3.2.5. *Other modes*

We identified four other potential response modes: quality change, tower height change, revenue and production ratio change, and cable corridor change. Starting with quality change, in the oil and gas industry, revenue based fees have been described as a cause for underinvestment (Black, 2002). Similarly, in the design phase of the offshore wind sector, such fees may manifest in the trade-off between turbines of different quality based on metrics such as, for example, availability or the shape of the power curve. For the purposes of this study, availability-based metrics are out of scope as they relate to the operations and maintenance optimization. However, if there were a diminishing return or increasing costs to the quality of turbines using the shape of the power curve within the relevant range, the developers may choose lower quality and accept less production considering that production was less valuable. Unfortunately, we could not find publicly available literature describing this issue in necessary detail.

A MWh- or revenue-based fee could create an incentive to install shorter towers by reducing the benefits of reaching possibly somewhat higher wind speeds at higher altitudes (Damiani, 2016).However, as short towers are already the current optimal tower design for offshore wind (Damiani, 2016), it was not studied further in this paper.

A per MWh fee may create a preference for earning more per MWh as opposed to producing more MWh which may then result in changes in wind farm layout. The siting of individual wind turbines is often optimized based on levelized cost of electricity wherein the most significant (and sometimes the only) considered factor is the maximisation of production (Grady et al., 2005; Mosetti et al., 1994). The optimization of a wind farm may take into account the fact that prices are likely higher during low and medium wind speed hours than during high wind speed hours (May 2017). However, the differential between the revenue and production potential for offshore wind has not been studied thoroughly enough to include in this study.

The area-based fee subcategory on cable corridors could be expected to incentivize the laying of cables in ways whereby the seabed use is optimized. However, most optimization literature on cables deals with the choice of cable type, sizing and path optimization by reducing the length of the cable, as opposed to the area of the cable corridor (Fischetti and Pisinger, 2018), which means it cannot be included in the present study.

3.3. Constraints

Seabed lease licences place constraints on wind farm design, which may affect the incentives created by the fees. This can be illustrated with an example. Assume that the government imposes a per km^2 fee that decreases the optimal size of a wind farm from 280 km^2 to 300 km^2. If the seabed lease license sets the maximum area at or below 280 km^2, such as 240 km^2, then the constraint negates the incentive entirely. The area of the wind farm has to be equal to or smaller than the constraint—240 km^2—with or without the fee (see Fig. 11). If the seabed lease license sets the maximum area at or above 300 km^2, such as 340 km^2, then the constraint has no impact on the incentive. The developer will likely decrease the area from 300 km^2 to 280 km^2 in line with the change in the optimal area. Finally, if the constraint is set in-between 280 km^2 and 300 km^2, such as 290 km^2, then the constraint partly negates the incentive, but not completely. The developer will decrease the area from 290 km^2 to 280 km^2. Constraints are also likely to be the determining factors in cases where there is no optimum as determined through the crossing of the marginal revenue and marginal cost curves (see Fig. 10).

In Figs. 12 and 13 one can see an illustration of a constraint. In the case of ScotWind, the constraints set out in the seabed lease agreements were seemingly less strict, allowing for a large variety of project sizes. There were only three projects that had were proposed to be as or almost as large (here defined as no more than 10 km^2 smaller than the maximum allowed area) as the constraints allowed them, though this is not a confirmation that without the constraints these projects would have been larger. Many additional factors present in the seabed lease auction including, for example, the boundaries of the auctioned areas and the location of other wind farms, as well as other concerns such as grid connection may have played a role. However, in comparison the seabed lease Allocation Round 4 all except 1 project proposed to be at or near one or more of the constraint boundaries, which, again may suggest that the constraints determined the size of the projects, though it does not confirm it.

In the example constraints shown in Figs. 12 and 13, it is apparent that seabed lease fees could impact the entire set of proposed projects while constraints only affect those that would have otherwise been designed in a way as to conflict with the constraints. If there were, for example, a socioeconomic reason to try to limit the area used by offshore

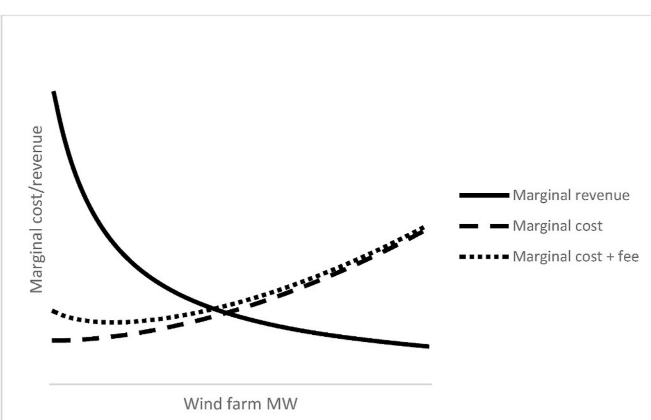

Fig. 10. Optimizing specific power. As the specific power of turbines is increased, output is increased, though at a declining rate as the wind speeds required to take advantage of greater maximum output increase and become rare. Upgrading transmission and offtake, and upscaling the generator and other necessary components leads to increasing costs. Adding a fee per unit of revenue or MWh to an offshore wind farm shifts the marginal cost curve up proportionately to the marginal revenue curve. As the marginal revenue curve declines, the gap between the marginal cost and marginal cost + fee curves narrows.

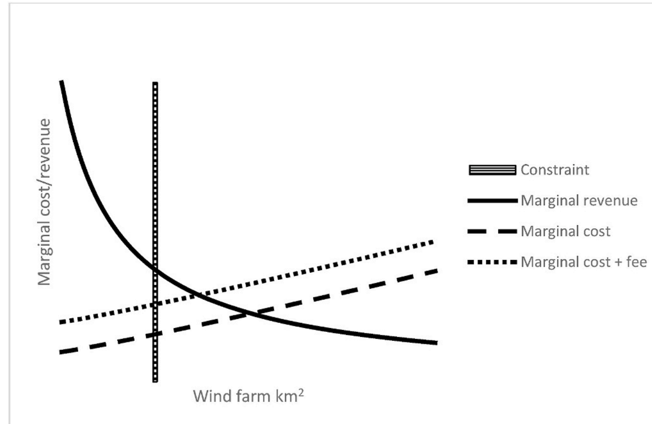

Fig. 11. Optimization with a constraint: Lowering the density of the wind farm increases the production due to a decline in the wake effect, though at a decreasing rate. The cost increases due to increased cabling costs and the utilization of less favourable seabed. The fee changing the optimal level of a design variable does not affect the realizable project design since it is determined by the constraint determining the maximum area of the wind farm at its intersection with the marginal revenue curve.

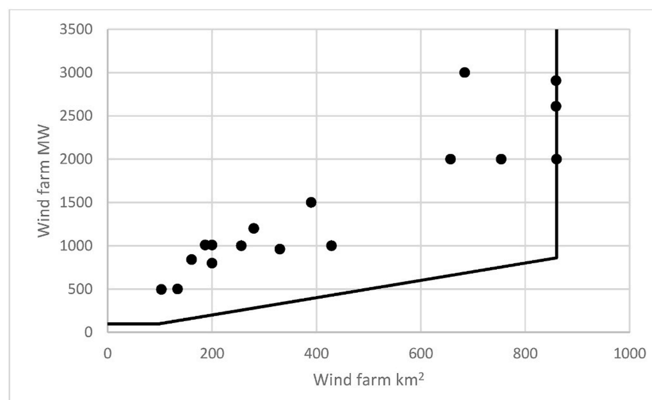

Fig. 12. The proposed areas and capacities of offshore wind projects from the Scottish ScotWind seabed allocation round. 17 projects were allocated (Crown Estate Scotland, 2022). The constraints set a maximum size of 860 km^2, a minimum density of 1 MW/km^2, and a minimum capacity of 100 MW (Crown Estate Scotland, 2020). The dots represent each of the projects and the line represents the constraints.

wind farms, an area-based fee may give all wind farm developers the incentive to use space saving measures where a relatively less stringent set of constraints (see Fig. 12) would only affect a few wind farms, possibly retaining some deadweight loss for some projects. An otherwise relatively more stringent set of constraints (see Fig. 13) is more likely to enforce space saving. Even if this approach were to achieve the desired change in design on average, if the possibilities of space saving vary between projects the constraints may change the design of some projects too much and others too little.

Seabed lease agreements and auction processes set many different types of constraints on the design of wind farms, as well as, e.g., the operating criteria and the ownership structures. We have created a short overview of the constraints in offshore wind farm lease agreements and auctioning processes that directly deal with the variables that we have examined in Table 6 to show the types of tools that are currently used to set hard boundaries for offshore wind farms, which may interfere with the optimization process. However, it is likely that wind farm design can be affected by constraints that arise from agreements other than the seabed lease agreements, such as the environmental impact analysis

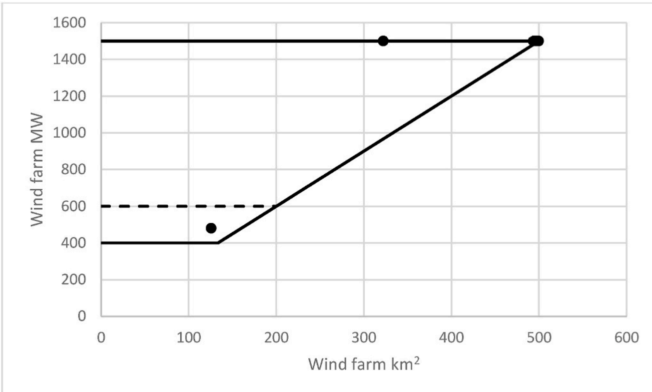

Fig. 13. The proposed areas and capacities of offshore wind projects from the ENG,WLS,NIR seabed Allocation Round 4. 6 projects were allocated with five proposing to build the maximum capacity and four of those proposing to projects at nearly the maximum size. The constraints set a maximum size of 500 km^2 and a minimum density of 3 MW/km^2, a minimum capacity of 400 MW. and a maximum capacity of 1500 MW (The Crown Estate, 2019). For the Dogger Bank lease area the minimum capacity was 600 MW (The Crown Estate, 2019). The dots represent each of the projects, the line represents the main constraints, and the dotted line represents the additional constraints that applied for Dogger Bank.

procedure.

4. Discussion

The analysis shows that the types of fees countries choose could have an impact on the design of offshore wind projects. Private actors can be expected to maximize profits both in the presence and absence of fees, though the design of the wind farm under each scenario may differ. A change in the optimal design of the wind farm means that changing the design of the wind farm leads to a decline in the fee that is greater than the loss in profitability associated with that design change. The new design will, therefore, generate fewer fees than a wind farm that had a design neutral fee. However, the design changes may be desirable from a socio-economic perspective even if it results in a lower level of private profitability. As described in section 3.3, the design response to fees is likely different to constraints and fees may, therefore, be more appropriate tools to achieve socioeconomically optimal outcomes. We discuss some of the considerations and provide an overview of the impact of fees in Table 7.

Area-, production- and revenue-based fees are likely to result in space saving by the developers. This would influence how much space the industry will need to achieve production targets. As economical seabed is a limited resource that is often in demand for multiple uses (Pettersen et al., 2023), it may be socio-economically beneficial to encourage density in some areas. These fees may, therefore, be suitable in areas where the amount of seabed useable for offshore wind is limited in addition to or instead of constraints. The optimal density differs based on the perspective. For private developers, the optimal density could be that which maximises profits. For the offshore wind industry in general, the optimal density could be that which allows for the lowest cost development across projects. For the green energy transition as a whole, the optimal density is that which allows societies to meet their ambitious clean energy production targets. From a broader socio-economic perspective, the optimal density can also consider alternative uses to seabed beyond just wind energy. There is no reason to believe that these different perspectives lead to the same, or even similar, optimal wind farm densities. Given the pace of technology change, the optimal density from each perspective likely varies over time. As there are other competing uses for (Spijkerboer et al., 2021) seabed and competition for seabed is expected to increase (Pettersen et al., 2023), fees could be used to influence wind farm seabed usage accordingly.

Table 6
Overview of the constraints in seabed lease licenses in the examined jurisdictions.

Constraint	Variation	Examples	Response mode as defined for the study
Location and/or size of the wind farm	Maximum and/or minimum area, or a designated area.	Netherlands: predefined sites (Netherlands Enterprise Agency, 2020b), ENG, WLS,NIR: maximum size and location restrictions (The Crown Estate, 2019), Scotland: maximum and minimum (partially) size, and location restrictions (Crown Estate Scotland, 2020), US: predefined sites, but resale and partition allowed (BOEM, 2019, 2018)	Wind farm area, number of turbines
Capacity	Minimum or maximum capacity of the wind farm, or the cables. (MW)	Netherlands: predefined cable size and minimum turbine capacity (Netherlands Enterprise Agency, 2020a), ENG,WLS,NIR: minimum and maximum capacity (The Crown Estate, 2019), Scotland: minimum capacity (Crown Estate Scotland, 2020)	Number of turbines, turbine specific power
Swept area and blade tip heights	Maximum rotor swept area and minimum and maximum tip heights	Netherlands: maximum rotor swept area and minimum and maximum tip heights (Netherlands Enterprise Agency, 2022)	Number of turbines, turbine scale, turbine specific power
Number of turbines	Maximum number of turbines	Netherlands: maximum number of turbines (Netherlands Enterprise Agency, 2022)	Number of turbines, turbine scale
Density	Minimum capacity to be installed per square kilometre. (MW/km^2)	ENG,WLS,NIR: minimum density (The Crown Estate, 2019), Scotland: minimum density(Crown Estate Scotland, 2020)	Wind farm area, turbine specific power

Offshore wind farms can have positive as well as negative environmental impacts (Galparsoro et al., 2022) depending on location (Virtanen et al., 2022) among other characteristics. While the negative impacts of offshore wind are deemed relatively small (United Nations Economic Commission for Europe, 2021), cumulative effects in large scale deployments may be greater (Goodale and Milman, 2019). Societies may have an interest in developing wind farms such that the balance between negative and positive impacts is best by, for example, encouraging greater deployment in the best locations in terms of environmental impacts in order to spare other areas. This type of planning also interacts with other design features such as, for example, foundation choice, as it is determined by seabed depth, which in turn drives some of the environmental impacts of offshore wind farms (Horwath et al., 2020), density (Masden et al., 2012) and overall resource use by influencing the number of turbines needed to reach a certain amount of output.

Turbines with lower specific power are expected to be more grid-friendly (Hirth and Müller, 2016; May 2017). Production-, revenue- and, especially, capacity-based fees may, therefore, increase the grid

Table 7
Overview of the effects of fees.

Response mode	Fee variable	Short description of effects
Spacing/Density change	km^2, MWh, euro of revenue	The fees may lead to an increase in the optimal density of a wind farm due to diminishing returns to reduced wind farm density. These changes arise from a reduction in the wake effect as well as, depending on the site, the variation in wind resource and depth of seabed throughout the site.
Turbine number change	km^2, MW, MWh, euro of revenue	The fees may lead to a reduction in the optimal number of turbines in the wind farm. As the number of turbines grows, there is likely a diminished positive effect from economies of scale for each additional turbine. There is more likely to be an effect if there is great variation in seabed depth and wind resource or when one considers overplanting. However, as the marginal contribution of turbines does not necessarily tend to zero, it is difficult to predict the level at which there would be an effect.
Turbine scale change	MWh, euro of revenue	The fees may lead to a slight preference of smaller turbines over larger ones. The optimum changes due to the fees reducing the production quantity advantage of larger turbines. However, the production changes are only a small part of the total change due to scaling, meaning that the effect is likely small.
Turbine specific power change	MW, MWh, euro of revenue	The fees may lead to a pressure to opt for lower specific power turbines. This may increase the capacity factor and/or market value factor, though lowering the density (MW/km^2) and production density (MWh/km^2). However, the choice of turbine might be heavily constrained, which may reduce the overall flexibility of the developers to respond to this incentive.

friendliness of offshore wind (unless the impact of reduced overplanting is larger and negative). This would come at the cost of lower production, which would need to be offset by more wind farms. The different pressures for optimization may also affect the types of turbines that will be developed in the future, with the potential that e.g. lower specific power turbines become more competitive.

The effects of the fees could be offset by subsidies if subsidies are paid using the same criteria as fees. They could partially or wholly counteract the design changes, or even create the reverse version of the design changes. An example of this could be the UK: Scotland case where rent and subsidy are both paid per MWh (BEIS, 2021; Crown Estate Scotland, 2020). This type of system could create increased risks if there is uncertainty or timing issues involved with the payments for the seabed and subsidies. If subsidies are paid using another criteria, the impact on design would remain and might even be increased as the higher the potential to receive subsidies, the greater the potential to change the design of the project for the purposes of paying higher seabed lease fees. This could be used to increase the power of the incentives to change the design of the wind farm.

5. Conclusion and policy implications

Seabed lease fees are often linked to wind farm design variables. We find that such fees can create incentives to change the design of wind farms. If the impacts of these changes are not analysed and carefully considered, the design changes may negatively impact private- and socio-economic outcomes. If used intentionally, however, fees can be used to guide wind farm designs toward better socio-economic outcomes, e.g., reduced space used, better environmental outcomes, or more power generation when most needed. As the fees let the developers make the economic trade-offs for their individual projects, they may result in more economical outcomes than simple constraints. They can also be used to complement constraints by incentivizing improvements beyond the level at which the constraints are set.

Area-based fees are likely to result in denser wind farms where wind turbines are installed closer together, which lowers production per turbine but increases production per km^2. It could be considered an alternative or complement to density or area constraints, encouraging the developers to utilize the seabed more intensely. It may also have an impact on the number of turbines in the wind farm, reducing the optimal size, though that effect depends heavily on the local conditions. However, all the discussed fees may also disincentivize overplanting.

Capacity-based fees are likely to encourage lower specific power turbines. This would lower the production per turbine but could provide the benefit of increased grid friendliness through the mechanism of the higher capacity factor leading to relatively more production taking in hours when electricity prices are higher. Similarly to the area-based fees, it may lead to a reduction in the number of turbines in wind farms. As this fee also disincentivizes overplanting, it may reduce the potentially positive effects.

Production- or revenue-based fees can incentivize both an increase in density as well as lower specific power. However, they can also have the impact of discouraging the use of larger wind turbines for wind farms of the same total capacity. This is due to the fact that they directly impact the revenue side, which is otherwise one of the reasons for opting for larger turbines despite their greater cost. There may be further effects that arise from the difference between production- and revenue-based fees, though this area needs further research.

Further research could consider other aspects of wind farms such as the operations and maintenance, installation and other processes involved. Expanding the number of categories would also enable adding more variables to the analysis, such as the time component in many of the fees, whereby the fee payable fee is reduced if the wind farm is commissioned faster. Furthermore, an analysis of all the factors together as opposed to one variable at a time could give further insights on the likelihood and magnitude of all of the change modes considered here. Additionally, future research could discuss how the seabed lease fees affect the sector in general.

As the fees could create design changes, they should be applied in a rational manner to create better socio-economic outcomes in terms of offshore wind farm design. As the decisions on the types of wind farm designs that win projects can affect the future development of the technology as well as the future availability of seabed for further development, the seabed lease agreements could be used to encourage development in ways that secure the long-term viability of this and other marine industries.

CRediT authorship contribution statement

Ahti Simo Laido: Writing – review & editing, Writing – original draft, Visualization, Methodology, Investigation, Conceptualization. **Tyler A. Hansen:** Methodology, Conceptualization, Supervision, Writing – review & editing. **Lena Kitzing:** Writing – review & editing, Supervision, Methodology, Conceptualization.

Declaration of competing interest

No conflict of interest statement.

Data availability

Data will be made available on request.

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Appendix A. Supplementary data

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