

# Technological learning potential of offshore wind technology and underlying cost drivers

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## ABSTRACT

Detailed analysis of technological learning of energy technologies is scarce. For floating wind, this is missing altogether. In this study, we applied experience curve and bottom-up cost modeling methodologies and assessed the long-term cost reduction potential and contribution factors of fixed-bottom and floating offshore wind in their mature markets. Further, to emphasize the role of strongly varying site characteristics of offshore wind farms and their influences, the grid connection cost is separately discussed from the total technology costs (Capital Expenditure and LCOE). Our assessment shows that, excluding grid connection costs, fixed-bottom offshore wind LCOE is 40 €/MWh at 31 GW cumulative capacity (2023–2024) and decline to  $28 \pm 3$  €/MWh by 100 GW. Floating wind LCOE is 123 €/MWh at 1 GW cumulative capacity (2027–2030) but decline to  $33 \pm 6$  €/MWh by 100 GW. Moreover, floating wind can achieve cost parity (i.e., 40 €/MWh, excl. grid connection cost) by deploying 21 GW, requiring 44 billion € of learning investment in the form of subsidies to compensate the price gap for the technology in the energy system. We also conclude that grid cost forms a substantial portion of total offshore wind cost, and an integrated offshore grid can efficiently future wind farms and reduce costs. Lastly, we compared our assessment with literature and found that fixed-bottom cost developments are commonly underestimated and the near-term developments for floating wind are overestimated due to limited understanding of component-level cost developments and developing financing conditions.

## Introduction

Meeting ambitious climate targets requires rapid deployment of CO<sub>2</sub> removal measures and renewable energy technologies [1]. With the historic cost reductions observed in the EU and UK [2], offshore wind is now considered well-established and a rapidly maturing renewable energy technology. Offshore wind is also expected to play a substantial role in future energy systems, with the International Energy Agency (IEA) projecting 560 GW of global offshore wind capacity by 2040 in its Sustainable Development Scenario [3]. The EU alone aims to achieve 300 GW of offshore wind capacity by 2050 [4], and the Climate Change Committee (CCC) estimates that the UK requires 75 GW of offshore wind capacity to meet its 2050 net-zero greenhouse emission targets [5]. Achieving such optimistic deployment targets within the next 30 years calls for an accelerated change of the sector's scale, informed policy

actions to overcome market barriers and resolve stakeholder differences [6], given the long development timescales for offshore wind farm project development (~7–10 years) [7].

Offshore wind technology is categorized into two variants, fixed-bottom offshore wind (FBOW) and floating offshore wind, based on the type of support structure employed for wind turbines in transferring their loads to the seabed and how their stability is achieved [8]. FBOW,<sup>2</sup> for which foundation structures are embedded into the seabed, has already shown significant technological progress and boasts a well-developed supply chain in the EU and the UK, building on the experience from 24 GW of installed capacity by 2020 [9]. Hereafter, the EU and UK are referred to as *mature markets* of offshore wind, similar to IEA [7]. Targeted incentives (e.g., feed-in-tariffs and technology-specific auctions), progress in marine spatial planning, and subsidies in the form of grid connection and site development have accelerated the deployments of FBOW in its mature markets [7], resulting in notable cost

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<sup>2</sup> Monopile, jacket, tripile and gravity-based foundation designs are categorized as Fixed foundation type.

Nomenclature			
Abbreviations		<i>Inv.Cost<sub>0</sub></i>	initial specific investment cost
AEP	Annual Energy Production in MWh	<i>Inv.Cost<sub>x</sub></i>	specific investment cost at cumulative installed capacity X
CAPEX	Capital Expenditure in M€/MW	LCOE	Levelized Cost of Energy in €/MWh
CCC	Climate Change Committee	LCOT	Levelized Cost of Transmission in €/MWh
CCGT	Combined-Cycle Gas Turbine	LIBOR	The London Interbank Offered Rate in %
CF	Capacity Factor in %	LR	Learning Rate in %
DECOM	Decommissioning Expenditures in €/kW	MWh	Mega Watt hour
DEVEX	Development Expenditure in M€/MW	O&M	Operation and Maintenance
<i>E</i>	Experience Parameter	OPEX	Operational Expenditure in €/MW/Year
EMPR	Expected Market Risk Premium in %	PL	Project Lifetime in Years
EU	European Union	RDD&D	Research, Development, Demonstration, and Deployment
EURIBOR	The Euro Interbank Offered Rate in %	SFEC	Single-Factor Experience Curve
FBOW	Fixed-Bottom Offshore Wind	<i>t</i>	Project Lifetime
GW	Giga Watt	TSO	Transmission System Operator
HVAC	High Voltage Alternating Current	UK	United Kingdom
HVDC	High Voltage Direct Current	WACC	Weighted Average Cost of Capital in %
<i>i</i>	Discount rate or Cost of Capital	Greek Symbols	
IAM	Integrated Assessment Models	$\beta$	beta, a measure of the sensitivity of expected asset returns to the expected market returns
IEA	International Energy Agency	$\delta$	Debt share

reductions in recent years (average LCOE at 2020 is 69 €/MWh,<sup>3</sup> a 54 % reduction from 2010 to 2015 values) [10], see Appendix A for illustration on fixed-bottom offshore wind cost reduction between 1990 and 2020. Bulder et al. [11] analyzed further cost reduction opportunities of FBOW using engineering cost modeling and experience curve approaches and stated that FBOW could reduce to 35–45 €/MWh by 2030. These deployments have also resulted in significant progress for offshore wind technology, in general, including convergence in foundation design and establishing mass production of components, control of cost overruns, increased technology know-how among market players, and development of technology-specific solutions (e.g., turbines, installation vessels, Operations & Maintenance (O&M), and subsea cables) [10,12]. In the EU and UK, 11.6 GW of additional capacity is expected between 2021 and 2023, and a clear pipeline of projects / announced tenders until 2030 is in place. Besides China, the primary market outside of the EU and UK, several secondary and tertiary markets, including Taiwan, the US, Korea, Vietnam, India, and Japan, have also shown increased interest in utility-scale deployments of FBOW, i.e., accelerated technology diffusion [9].

As outlined above, the FBOW is well-established and provides cost-competitive electricity in their mature markets [2]. However, to face the rising issues with nearshore spatial constraints and interests in exploiting better wind resources available in deeper waters (where fixed-bottom foundations are not suitable) [6,13], deployment of floating foundations<sup>4</sup> is inevitable [14]. floating wind is an emerging variant of offshore wind, for which the foundation is tethered to the seabed using mooring and anchor systems. This setup allows motion of wind turbines with certain degrees of freedom. Further, the commercial experience with floating wind is currently limited, with multiple foundation designs deployed as single-device prototypes and small-scale demonstrations alone [15]. In other words, there is a lack of commercial floating wind projects. Each floating foundation design has its pros and cons (as summarized in Appendix B). Factors including manufacturing complexity, material needs, O&M accessibility, and local content requirements (if any), will influence the foundation design

convergence in the market. The current small-scale floating wind deployments majorly rely on component designs, procedures, and practices from existing Oil & Gas and FBOW industries. The floating wind industry needs to develop dedicated solutions and address existing technology-specific barriers to advance the technology to a commercial scale [14]. The barriers include the development of high voltage dynamic cables, cable connectors (e.g., wet-mate), floating substations, improved understanding of coupled behaviour of floating wind turbines (i.e., the interaction between floater, turbine, mooring, anchor, and dynamic cables at sea), new vessels or alternative lifting solutions for 15 + MW turbines [14,16–18].

Despite the emerging status of the floating wind and identified technological barriers yet to be overcome, several studies have claimed that its cost reduction potential is significant; for example, 50–70 €/MWh by 2030–2035 [14,19–21]. In those studies, transparency about the methodology, empirical evidence, and detailed assumptions leading to estimating the Capital Expenditure (CAPEX) and Levelized Cost of Energy (LCOE) developments are limited, consequently restricting the understanding of role of contributing factors. In literature, estimation of current costs of floating wind farms based on engineering assumptions [22,23] and parametric equations [24–26] also exist. However, the long-term cost assessment of floating wind with a detailed account of contributing factors is not available, i.e., a critical limitation in literature. The case is less similar to FBOW due to its well-established status [11,22–24], but uncertainty in predictions exists [15,25,26].

Moreover, insights into two other critical issues relevant to offshore wind were lacking in the existing literature. First, achieving such drastic cost reductions for floating wind (50–70 €/MWh by 2030–2035) depends on achieving several preconditions, including convergence in technology design and solutions, supply chain development, and building a technology track record to achieve investor confidence [7,27], which were not clearly emphasized. Second, contrary to the onshore renewable energy technologies, grid connection (offshore and onshore) forms a significant component in the final energy cost of offshore wind. As wind farms are installed in challenging conditions (deeper waters and farther from the shore [10]) over time due to the nearshore spatial constraints and interest in exploiting better wind resources, the grid connection configurations, development model, and their costs (8–18 €/MWh [28]) are expected to become a critical element in determining the role of offshore renewables in the future energy system [29,30]. In summary, this study addresses the three critical gaps

<sup>3</sup> All values in this study are represented in 2015 EUR values unless otherwise stated.

<sup>4</sup> Tension-leg platform, semi-submersible, barge and spar foundation designs are some of the common floating foundation design types.

discussed above, 1) development of a detailed and transparent methodology leading to estimation of offshore wind costs (CAPEX, LCOE); 2) outlining pre-conditions or market barriers necessary for technology to reach commercialization; 3) analysing the impact of site characteristics on grid connection costs of offshore wind. Santhakumar et al. [31] recently analyzed the cost reduction observed for FBOW technology using a detailed methodology, combining empirical learning curves and bottom-up cost modeling. However, the focus of the study was only for FBOW and the time period between 1990 and 2020 alone. In this study, the cost reduction (CAPEX, LCOE) for both FBOW and floating wind towards 2050 is derived and contributing factors are outlined. These long-term technology cost forecasts are also critical inputs in Integrated Assessment Models (IAM), largely influencing its outcomes, including system cost developments, technology mix, deployment scenarios, and transition pathways. Such outputs are commonly used to inform public policy designs, emphasizing the need for certainty in future technology costs [32,33].

The analysis and results of this study are structured as follows. First, we use bottom-up engineering cost modelling to estimate and describe the CAPEX cost components of both variants of offshore wind. We then assess CAPEX developments based on increasing cumulative capacity, i. e., experience curve approach (Section 3.1). For LCOE, key assumptions reflecting the expected technological and market developments are described first, followed by constructing detailed LCOE developments and discussing the impacts of individual factors (Section 3.2). Second, grid connection cost development and its critical role in future energy system planning are discussed (Section 3.3). Lastly, we conclude with five major implications for the offshore wind industry, policymakers, and researchers (Section 4).

## Theory and methods

### *A brief introduction on technological change process*

Technological change is a complex process involving stages of development and diverse characteristics [34,35]. In literature, several theoretical frameworks informing the conceptual basis of this process exists. However, the standard paradigm involves the Research, Development, Demonstration, and Deployment (RDD&D) activities leading to cost and performance developments of energy technologies [36–38]. Such conceptual frameworks have also been applied to describe the development and diffusion of offshore wind technology. For example, Dedecca et al. described offshore wind development in three phases: innovation, market adaptation, and market stabilization, and further explored market strategies available for private players in the offshore wind market [39]. Van der Loos et al. argued that the underlying institutional construct in the European offshore wind market had led the technology to rapidly adopt a dominant design in the early stages of development. The study continued that radical experimentations, commonly observed in the early development stages of energy technologies, only emerged after 20 years of offshore wind technological diffusion [40]. However, Santhakumar et al. empirically analyzed the FBOW developments in the European region and stated that the overall technological progress of offshore wind has indeed followed a standard sequential development pattern commonly outlined in the literature [10,41] (as further briefly illustrated in Appendix C). The development began with the formative phase, where the deployment of small-scale FBOW commercial units between early 2000 and 2010 enabled learning opportunities and initiated supply chain development and market creation for the technology. A rapid unit-upscaling phase<sup>5</sup> followed next, with concurrent and increased diffusion of the technology in energy systems (growth phase) [10]. Now, next-generation design

<sup>5</sup> The unit scale economies refer to cost reduction through upscaling of a product size or capacity, e.g., wind turbine rated capacity.

(floating wind, initially considered expensive) has emerged to benefit from FBOW developments and further progress the technology.

### *Method*

Offshore wind is a complex large-scale energy system [42,43] and several approaches have been followed in the literature to foresee its cost reduction. The experience curve approach, which assumes the technology cost to decline a certain percentage for every doubling of its output (an aggregate proxy for experience gain), has been extensively applied to predict offshore wind cost reduction (FBOW). However, the approach poses some limitations, including omitted variable bias, the inability to disaggregate the learning process and detail the underlying contributing factors and foresee radical changes in developments [38]. On the other hand, engineering assessments involve detailed component-level cost modeling and describes the techno-economic factors influencing the developments. Nevertheless, only a subset of potential factors are generally considered in the analysis, and the development assumptions are based on expert knowledge or observations from analogous technologies in the market [20,44]. Lastly, in the expert-elicitation approach, information from subject-field experts is collated to understand the technology's potential cost and performance improvements. This approach is beneficial when historical information is limited [25]. Of all approaches followed in the literature, technology cost projections from model-based methods, like the experience curve approach, are observed closer to the realized developments than the elicitations [26].

In this study, we leveraged the merits of bottom-up engineering cost modelling and experience curve methodology to derive detailed long-term cost assessments (LCOE) for offshore wind technology [38]. Bottom-up engineering cost modelling was first used to estimate and describe offshore wind variants' CAPEX breakdown and cost centers, reflecting near-term commercial-scale deployment characteristics (inputs are summarized in Appendix D). The assumed fully commissioned<sup>6</sup> year is 2023–2024 for FBOW (expected to have achieved financial close in 2020–2021) and 2027–2030 for floating wind (expected to have initiated project development in 2020–2021) [9]. The CAPEX estimates calculated during the above-mentioned periods serve as a starting point for our cost outlook. The long-term CAPEX developments for offshore wind variants were then derived using the experience curve approach (Wright's law) [45].

LCOE developments of offshore wind were then estimated by considering CAPEX, discount rate ( $i$ , in %), project lifetime ( $t$ , in years), Annual Energy Production ( $AEP$ , in  $MWh$ ), Operational Expenditures ( $OPEX$ , in  $€ MW^{-1} yr^{-1}$ ) and Decommissioning expenditures ( $DECOM$ , in  $€$ ) [42]. The inputs made and expected developments of these factors are detailed in the following sections.

### *Separating the influence of varying site characteristics from cost outlook*

As mentioned above, the experience curve approach poses omitted variable bias. That is, the effect of site characteristics (water depth and distance to shore), which was shown to have a negative impact on technology cost [43], is not considered in the LR (single-factor experience curve model) inherently. The site characteristics of the future deployments are also highly uncertain, as it depends on the regulatory frameworks on wind farm site development [7], developer preferences, and technology readiness [46]. Hence, multi-factor experience curve model could not be used without accurate site characteristics data [31]. Therefore, in this study, we have reverted back to the SFEC model and the influence of varying site characteristics is considered by separating the offshore wind LCOE into two components. First, the wind farm cost alone until the offshore substation (i.e., wind farm assets installed

<sup>6</sup> Fully commissioned year refer to the time when the wind farm begins its operation

offshore) was considered. Second, the grid connection cost from offshore substation to onshore grid connection point was estimated separately, based on the wind farm's distance to shore and annual capacity utilization of the transmission asset.<sup>7</sup> These two cost components can be added to arrive at the final levelized energy generation cost for a future offshore wind farm.

### Estimating CAPEX developments

In bottom-up engineering cost modeling, the total CAPEX of offshore wind technology is decomposed into six cost categories, as shown in Equation (1).

$$CAPEX_{(Excl.gridconnection)} = Cost_{Devex} + Cost_{turbine} + Cost_{foundation} + Cost_{Elec.Infra} + Cost_{Installation} + Cost_{OtherCAPEX} \quad (1)$$

In these equations,  $Cost_{Devex}$ ,  $Cost_{turbine}$ ,  $Cost_{foundation}$ ,  $Cost_{Elec.Infra}$ ,  $Cost_{Installation}$ ,  $Cost_{othercosts}$  refer to development expenditure, turbine supply cost, foundation supply cost, electrical infrastructure supply cost, and other project expenses (insurance, project management, and contingencies). The component costs applied in the bottom-up engineering cost modelling and the methodology are summarized in Appendix E. The long-term CAPEX developments for offshore wind were then derived by applying an LR, as shown in Eq. (2).

$$Inv.Cost_X = Inv.Cost_0 * (X/X_0)^{-E} \quad (2)$$

$Inv.Cost_X$ ,  $Inv.Cost_0$ ,  $E$  refers to specific investment cost  $M€MW^{-1}$  of the offshore wind technology at cumulative installed capacity  $X(GW)$ , the initial specific investment cost of the offshore wind technology at  $X_0(GW)$  unit of cumulative installed capacity, and the experience parameter.  $Inv.Cost_0$  is the CAPEX estimated using Eq. (1). The experience parameter in Eq. (2) was calculated from the LR ( $LR = 1 - 2^{-E}$ ).

### LR assumptions for CAPEX developments

Modular technologies (solar PV, LED, battery) achieve product standardization faster than complex compound technologies and yield cost reduction mainly through increased deployments (e.g., learning-by-doing), i.e., they depict high LR's for CAPEX (>10–15 %). Compound energy technologies (Nuclear power plants, CCGT systems, offshore wind), on the other hand, take extended periods to achieve technology standardization and develop know-how knowledge in the market. Their cost reduction is achieved through experimentations, design optimization, R&D, and unit-scale economies; before learning-by-doing becomes prevalent, i.e., they depict low LR's for CAPEX (<10–15 %) [47,48].

For FBOW, Santhakumar et al. [10] estimated LR for offshore wind using the historic wind farm project prices from the EU and the UK, see Appendix F. The LR results from the study is used here. The CAPEX breakdown estimated for FBOW, reflecting deployment characteristics over the period 2023–2024, was assumed as  $Inv.Cost_0$ ; refer to Equation (2). Thirty-one GW (approx.) of cumulative installed capacity is expected by the beginning of 2023 for FBOW [9], which was used as  $X_0$  to project CAPEX costs further up to 100 GW of cumulative installed capacity.

For floating wind, empirical LR could not be estimated, as there were no large-scale commercial deployments in the market by 2020. ORE Catapult (the UK's Technology Innovation and Research Centre for Offshore Renewable Energy) reported 9.5 % LR for floating wind based on two analyses, their understanding of supply chain dynamics, and innovation roadmaps published by Offshore Wind Innovation Hub &

European Technology Innovation Platform on Wind Energy [19,49,50]. We assumed a similar estimate but with a wide confidence interval (LR:  $8 \pm 3$  %) to include the potential development uncertainties; for example, floating wind builds on the existing progress of FBOW (e.g., turbine technology, vessels, O&M practice, supply chain) which might limit its development opportunities or new radical innovations in design and fabrication processes can offer breakthrough developments for floating wind. The CAPEX breakdown estimated for floating wind, reflecting deployment characteristics over the period 2027–2030, was assumed as  $Inv.Cost_0$  in Equation (2). One GW was assumed as the initial cumulative installed capacity ( $X_0$ ), which was also considered a learning threshold when cost overruns are controlled, performance shortfalls are corrected, foundation design convergence begins, and project costs start to decline [19,51]. This assumption is suitable as the floating wind variant is expected to build on technological progress already achieved by FBOW in the market (e.g., turbine technology, supply chain, installation, and O&M practices).

### Estimating LCOE developments

LCOE is the €/MWh amount the offshore wind project developer must earn for each MWh electricity generated to cover the total costs incurred over the project lifetime. It is also a critical metric that significantly impacts investment and policy actions and compares different technologies' competitiveness in the market; however, it neglects system-level values [3,52]. The LCOE was estimated as shown in Equation (3).

$$LCOE = \frac{CAPEX + \left( \sum_{n=1}^t \frac{OPEX}{(1+i)^n} \right) + \frac{DECOM}{(1+i)^{t-1}}}{\sum_{n=1}^t \frac{AEP}{(1+i)^n}} \quad (3)$$

The inputs of LCOE, discount rate, capacity factor, OPEX, Decommissioning costs, are discussed in a detailed manner in Appendix G-K. However, for reference, the approach and resulting inputs are briefly summarized in the following sections.

### Discount rate

Renewable energy technologies are considered capital-intensive, for which a significant portion of their lifecycle costs is incurred upfront [53]. Hence, the cost of capital is one of the significant factors driving the cost of renewables. In this study, project finance capital structure is assumed for discount rate estimation of offshore wind, as this structure theoretically ties the cost of capital to the project risks [54]. In project finance, the Weighted Average Cost of Capital (WACC), where both debt ( $\delta$ , %) and equity ( $1 - \delta$ , %) are proportionally weighted, is used as cost of capital of the project. The estimations of the cost of debt and equity were based on market indexes and technology risks, see Appendix G. The cost of capital of FBOW remained at 4 % in real terms. The cost of capital of floating wind decreases from 8.38 % (real) at 1 GW cumulative installed capacity to 4 % after roughly 30 GW of cumulative installed capacity.

### Capacity factor

The Annual Energy Production (AEP) in Equation (3) is a function of the Capacity Factor (CF). Capacity factor refers to "the ratio of the amount of electricity produced by the wind farm to its total potential, based on nameplate capacity, over a period of time (usually one year, to account for seasonal variability in output)" [55]. As mentioned earlier in this study, the site characteristics of the future deployments are highly uncertain. However, it is expected that the deployments will move farther offshore (more challenging site conditions but with stronger wind resources) as technology becomes mature with experience and to overcome rising nearshore spatial constraints. To understand the potential capacity factor development, imaginary sites at different distances to shore were assumed and capacity factors were estimated, e.g., observe wind speed variation in the North Sea region shown by Geyer

<sup>7</sup> Annual capacity utilization refers to the extent to which the total transmission capacity has been utilized in a year, which can be represented in full load hours or capacity factor.



et al. [56] and KNMI North Sea wind atlas [57], and then, estimate capacity factor developments based on openly available power curves [58,59]. Detailed estimation methodology can be found in Appendix H.

#### OPEX

OPEX refers to expenditures incurred for operating and maintaining the wind farm assets, including predictive and corrective maintenance costs (onshore and offshore), insurance, and management costs. In specific markets, wind farm owners also incur transmission charges and seabed rent as operating expenses. Furthermore, from the wind farm owner's perspective, the opportunity cost of turbine downtime (forgone revenue) as a direct result of the inspection, maintenance, and repair tasks are also sometimes included as operating expenses [60]. However, those expenditures and foregone revenues are excluded from the calculations in this study, and the wind farm's LCOE estimates will increase upon including them. The OPEX values for this study are derived from a combination of literature review and experience curve forecasts; refer to Appendix I. For FBOW, the OPEX decreases from 55 k€ per MW per year at 31 GW of cumulative installed capacity to 40 k€ per MW per year after 37 GW of cumulative installed capacity. For floating wind, the OPEX decreases from 75 k€ per MW per year at 2 GW of cumulative installed capacity to 40 k€ per MW per year after 11 GW of cumulative installed capacity.

#### Decommissioning cost

Decommissioning offshore wind farms mean removing wind farm assets, reinstatement of the site, and clearance verified upon lease termination. To ensure the decommissioning of these OWF's and avoid public cost burden, regulators in most markets require developers to set aside funds for future use upfront or provide security that the developer will make funds available in the future [61]. The study assumes the wind farm's total installation cost is equal to DECOM expenditure (8% of FBOW's CAPEX, 3% of FOW's CAPEX),<sup>8</sup> and the developer will incur this cost after the end of the project lifetime. This assumption neglects the learning that will be gained in the marine engineering practices, vessel improvements over time, and residual value that might be attached to the assets (which could be sold or used in the event of repowering) at the end of the project lifetime. Nevertheless, this omission's impact will be negligible on the LCOE, as the DECOM expenditure is discounted after the end of the project lifetime.

#### Separating impact of financing costs

Moreover, to separate the financial expenditures from the LCOE, we first estimated a baseline LCOE at a 0% discount rate, as illustrated in Equation (4). This step resulted in the actual contribution of the CAPEX, OPEX, and DECOM in the LCOE. Subsequently, we estimated the LCOE again at the discount rates derived in this study, using Equation (3). The difference between the LCOE at a discount rate ( $i$ ) and the baseline LCOE ( $i = 0\%$ ) was assigned as financing expenditures for the offshore wind technology.

$$LCoE_{i=0} = \frac{CAPEX + (\sum_{n=1}^t OPEX) + DECOM}{\sum_{n=1}^t AEP} \quad (4)$$

#### Grid connection cost

As mentioned in Section 2.2.1, these grid connection cost for a wind farm from an offshore substation to an onshore grid connection point is estimated separately as Levelized Cost of Transmission (LCOT). Here, the LCOT is defined as the €/MWh amount the TSO must charge the wind farm owner to cover the cost of developing and operating an offshore grid connection system to the shore.

<sup>8</sup> This input is calculated by assuming DECOM as 65% of installation cost [61]; refer to Appendix D.

Different grid connection topologies exist, namely, radial, hub, and hybrid systems [29]. A radial connection directly connects the wind farm to the onshore grid connection point (point-to-point connection, a prevalent grid connection concept for offshore wind farms). A hub connection clusters more than one wind farm in an offshore hub (facilitating asset sharing) and transfers the electricity generated to an onshore grid connection point. The hybrid connection allows the transmission asset to be used as a grid connection for the wind farms and as an interconnector where electricity can be traded in both directions. In this study, the LCOT for three radial HVAC connection capacities (350, 700, and 1050 MW) are estimated. Beyond ~ 1000 MW and with longer transmission distances, the HVDC system is expected to be competitive [62]. Moreover, the LCOT was also estimated as a matrix with annual capacity utilization<sup>9</sup> and distance to shore as variables to illustrate the influence of site characteristics on technology costs.

The capital expenditure of the grid connection was first calculated by totaling the investments for both offshore (semi-submersible HVAC offshore substation, export cable) and onshore (onshore substation, underground cable) equipment, Equation (11). By assuming project lifetime ( $t = 30$  years), discount rate (4%),<sup>10</sup> and OPEX [30] (1% of CAPEX), the LCOT was estimated [30], using Equation (12). No learning assumptions were considered here, as HVAC is regarded as mature technology [63].

$$CAPEX_{gridconnection} = CAPEX_{offshoregrid} + CAPEX_{onshoregrid} \quad (11)$$

$$LCOT = \frac{CAPEX_{gridconnection} + \left( \sum_{t=1}^n \frac{OPEX_{gridconnection}}{(1+i)^t} \right)}{\sum_{t=1}^n \frac{AEP_{windfarm}}{(1+i)^t}} \quad (12)$$

The summary of the technical characteristics assumed is provided in Appendix L, and the detailed assumptions can be seen in the cost estimation model made available with the article.

#### Reference LCOE, breakeven capacity and learning investment

A reference LCOE is commonly chosen in similar studies to benchmark the development of technology in the context. More commonly, the conventional fossil fuel technology cost is chosen [64]. Here, the reference LCOE of 40 €/MWh, reflecting the wholesale electricity price developments in European electricity markets between 2017 and 2020 [65], is used to benchmark offshore wind development. This assumption is made because wholesale electricity price reflects the cost of generating and delivering electricity in the system and can be used as an appropriate metric to determine the price gap that needs to be compensated for emerging technologies (as subsidies/incentives, e.g., Feed-in-Tariffs). Further, the cumulative installed capacity required to achieve the reference LCOE is referred to as *breakeven capacity* in this study [45].

Learning investments for a technology refer to the additional costs, as investments, necessary to make the technology cost-competitive in the market [45]. These additional costs are generally provided through several market mechanisms, including direct and indirect transfer to producers or consumers to compensate the price gap, preferential tax treatments, R&D, direct investments in energy infrastructure, trade restrictions, and regulations in the market [66]. In this study, we only

<sup>9</sup> Annual capacity utilization refers to the extent to which the total transmission capacity has been utilized in a year, which can be represented in full load hours or capacity factor. Here, the capacity factor refers to the ratio of energy delivered to the onshore grid (after the transmission losses) to the total energy capable of transmitting in a year.

<sup>10</sup> Transmission System Operator (TSO) have better access to cheaper capital due to their regulated revenue model. In some cases, they can even recover the incurred losses by passing charges to their consumers.

estimated the cumulative additional costs required to close the price gap between the LCOE of the technology and a reference LCOE, as learning investments, as shown in Equation (13). Therefore, it should be highlighted that total learning investment will increase upon including the excluded incentives. Reference LCOE assumption is 40 €/MWh; see Section 2.6.

$$\text{Learning Investment} = \sum_{n=1}^{\text{break even capacity}} (\text{LCOE}_n - \text{ref.LCOE}) * \text{AEP}_{n,\text{MWh}} * \text{Project lifetime}_n \quad (13)$$

## Results and discussion

### CAPEX outlook of offshore wind and contributing factors

As discussed in Section 2.3, the CAPEX breakdown estimated using the bottom-up engineering cost-modeling is first used to describe major cost drivers. Then, experience curve approach was applied to derive future CAPEX developments.

Fig. 1 (a) shows the component level CAPEX breakdown for FBOW and floating wind, estimated using bottom-up cost modeling. It is to be reminded here that floating wind is considered emerging, and FBOW is considered well-established in the market. Nevertheless, a comparison of CAPEX at the current development state of each variant is warranted as floating wind builds on technological progress already achieved by FBOW, excluding the foundation component and associated modifications (refer to Appendix E for more details). The five major differences observed are as follows: 1) The high proportion of fixed costs involved in the project development currently results in higher specific Development Expenditure (DEVEX) for floating wind (assumed project scale in Fig. 1 (a): 1020 MW for FBOW and 300 MW for floating wind). 2) The higher turbine supply cost assumption for floating wind reflects the modifications required for floating wind turbines (tower and control software to compensate floater motions) and reduced scale of turbine orders (assumed no of turbines in Fig. 1 (a): 85 for FBOW, 25 for floating wind). 3) The foundation cost of floating wind is roughly seven times higher than that of FBOW, with the semi-sub floater supply cost being the major cost contributor. In FBOW, the site's water depth directly influences the foundation design and material needs, as the embedded foundation structure is raised from below the seabed to roughly 15–20 m

above the water level. However, for a floating wind foundation, the water depth primarily influences the mooring and anchor costs (which form less than one-third of the total foundation cost), as the foundation structure is tethered to the seabed. Refer to Fig. 1 (b) for a comparison of foundation cost breakdown. 4) floating wind installation does not require expensive heavy-lift vessels (typical for FBOW), as primary lifting and assembly operations for the wind turbine structure can be made onshore (or deep nearshore waters, specifically for spar foundations [67]) and towed to the wind farm site using less expensive anchor handling vessels and tug boats. 5) floating wind has higher construction insurance and contingency costs due to the limited track record, resulting in increased “Other CAPEX” costs.

Compared to FBOW [10], potential cost drivers behind long-term CAPEX developments of floating wind have not been assessed in the literature previously. Therefore, technical and economical design variables of floating wind were varied to determine factors with the highest impacts,<sup>11</sup> see Fig. 2. The changes in DEVEX and the day rates of installation vessels/equipment have a minor impact, as these cost components form a smaller portion of the total CAPEX. Nevertheless, the influence of weather conditions (e.g., delays) can increase wind farm's installation cost. Sharing an anchor system between multiple wind turbines or increasing the number of mooring lines to ensure an acceptable risk profile for the turbine's station-keeping (mooring configuration can vary across foundation designs [17]) also has a minor impact. Water depth variation has a minor but counterintuitive effect on CAPEX because the mooring line's vertical suspended length is shorter in shallow waters (roughly 60–100 m deep). Therefore, heavier steel chains are needed to develop the necessary restoring forces for station-keeping. However, in deeper waters where longer mooring lengths are necessary, lighter steel chains are sufficient to develop necessary restoring forces for station-keeping, thus reducing the material costs [18,68].

Moreover, three other factors, unit-scale economies, turbine, and floater supply cost, have been observed to have the highest impacts on CAPEX, i.e., major cost drivers. The installation of turbines with higher rated power reduces the number of turbine positions in the wind farm (thereby, reduced installation operations, mooring and anchoring systems) and specific material consumption in the Balance of Plant (e.g., foundation mass and cables), which decreases the specific CAPEX of the wind farm (unit-scale economies effect) [10,71]. However, the unit-scale economies effect will diminish when the cost of developing and installing turbines with higher rated power exceeds the benefits it brings to the final cost of energy. Studies have already noted that turbine upscaling is outpacing the supporting technologies (cranes, vessels with increased height, reach, and lifting requirements) required to install them [12,19], indicating potential bottlenecks for future deployments. The higher impacts observed for turbine and floater supply costs show that notable cost reduction can be achieved by converging the technological design faster and initiating mass production of the technology components (i.e., learning-by-doing). Equally, diverged focus on foundation designs and market concentration in the supply chain can hamper potential cost reduction for floating wind.

As a final step, CAPEX development for FBOW and floating wind was projected until 100 GW of cumulative capacity from its assumed initial deployment level (current status) using experience curve approach. The Learning Rate (LR) applied to FBOW was based on historic project prices and cumulative capacity. For floating wind, empirical LR could not be estimated, as there were no large-scale commercial deployments in the market. Therefore, LR was assumed based on the theoretical understanding outlined for large-scale energy technologies' developments and

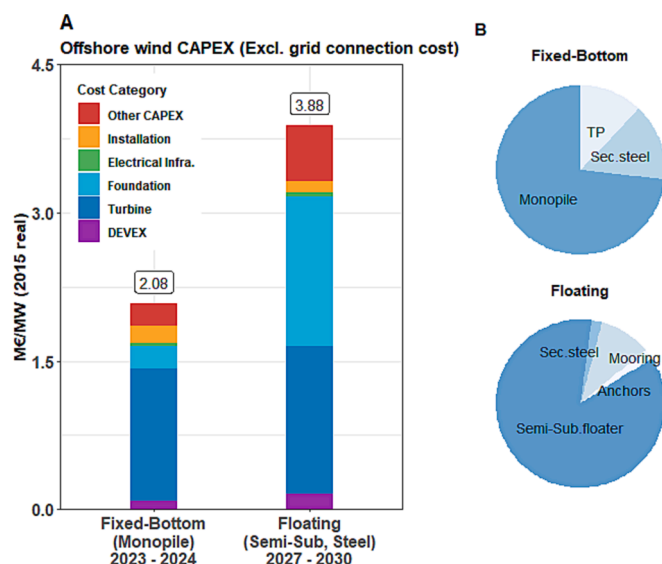


Fig. 1. Offshore wind technology CAPEX breakdown. a) CAPEX breakdown for FBOW and floating wind estimated using bottom-up engineering cost modelling (see Appendix D for wind farm characteristics). b) Comparison of cost breakdown for foundation systems.

<sup>11</sup> It is to be reminded here that the factors mentioned here are subset of techno-economic variables that majorly impacts wind farms costs, and the combination of these factors will influence the cost developments of floating wind.

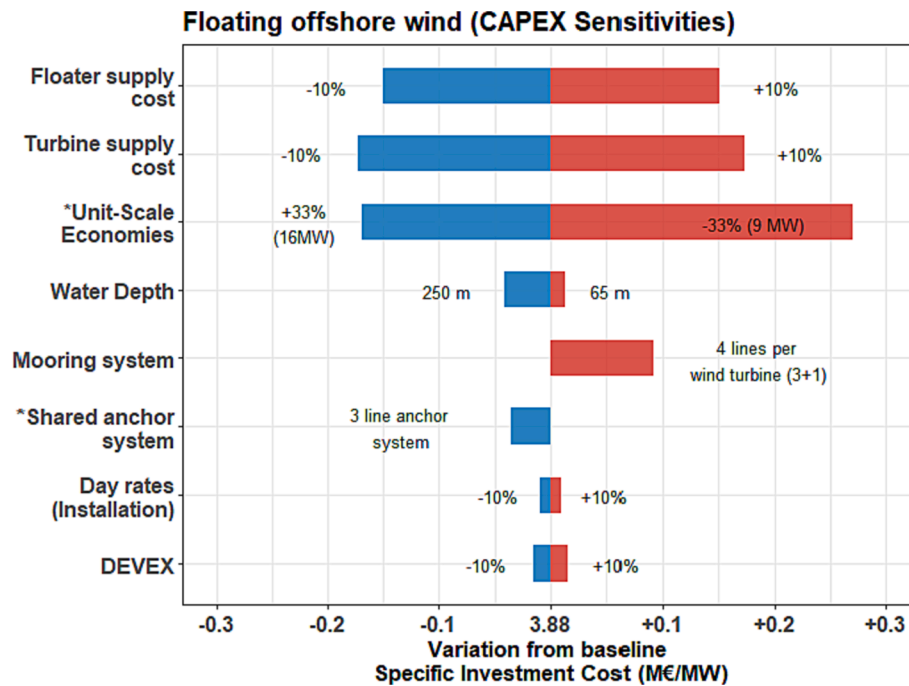


Fig. 2. Tornado chart describing the CAPEX sensitivities of several technical and economical design variables of floating wind. \*Unit-scale economies: Turbine supply cost variations are excluded here. \*Shared anchor system: Driven pile anchor is assumed for shared anchor system configuration (instead of drag embedded anchor) because of the requirement to withstand cyclic loads from mooring systems in different directions [69,70].

estimates applied in past studies (see Section 2.3.1). The LR depicting technology developments are also subject to uncertainty due to several factors. These factors include the limitations of the underlying data, market shifts, commodity price changes, cost overruns, and potential step-change developments through Research & Development (R&D) [72]. These uncertainties were considered by estimating 95 % standard error-based confidence interval (FBOW) or by including a potential range (floating wind) for LR. The initial specific CAPEX applied in the experience curve projection is from the bottom-up engineering cost modeling discussed above. Fig. 3 illustrates potential CAPEX developments, which reduces to 1.87 M€/MW for FBOW and 2.23 M€/MW for floating wind by 100 GW.

#### LCOE outlook of offshore wind and the drivers of technological learning

The LCOE of offshore wind technology was estimated as described in Section 2.4. Fig. 4 shows the detailed component-level LCOE developments expected for FBOW and floating wind. LCOE reduces to 28.4 €/MWh for FBOW (30 %) and 32.0 €/MWh (74 %) for floating wind by 100 GW from its assumed initial deployment level. The reference LCOE of 40 €/MWh, reflecting the wholesale electricity price developments in European electricity markets between 2017 and 2020 [65], is used to benchmark offshore wind development; refer to Section 2.6. FBOW breakeven at 31 GW of cumulative capacity and is expected to be reached between 2023 and 2024. floating wind could achieve breakeven by deploying roughly 21 GW of cumulative capacity, requiring 44 billion € of learning investment. When the LR uncertainties of floating wind are considered, the breakeven capacity ranges between 14 and 64 GW, requiring 34–70 billion € of learning investment.

Furthermore, the impacts of identified factors behind potential LCOE reduction of offshore wind variants are estimated (Fig. 5) and detailed below. 1) *Technology Costs (CAPEX, OPEX, and DECOM)*: The reduction in technology costs contribute to 5.2 €/MWh reduction (43 %) for FBOW and 35.6 €/MWh reduction (39 %) for floating wind in the overall LCOE development towards 100 GW from its initial assumed cumulative capacity. Besides learning through deployments (learning-by-doing), the

rapid unit-upscaling of offshore wind turbines that occurred after 2010 has reduced the specific CAPEX, OPEX [73], (expected) decommissioning expenditures, and also increased the Annual Energy Production (AEP) for FBOW [10]. The further upscaling of turbines<sup>12</sup> (15 + MW) is expected to advance the technology costs for FBOW and floating wind. However, learning-by-doing is expected to play a more prominent role in further years as the unit-scale economies effects are diminishing ([10] and see Fig. 2) and potential bottlenecks in terms of installation are arising.<sup>13</sup> Also, for floating wind, the technological barriers mentioned earlier need to be addressed first to benefit from continuous cost decline. O&M strategy varies depending on distance to shore, scale of the project, FBOW or floating wind, resulting in OPEX differences between wind farm projects [73,74]. Nevertheless, developments in unit-upscaling, project size, vessel improvements, improved marine practices and learning has decreased the OPEX over time (in € per MW per year) [75,76]. 2) *AEP (a function of CF)*: Future turbine platforms with larger rotors result in reduced specific power rating for the wind turbines<sup>14</sup>; see Fig. 6 (a). Reduced specific power rating, increased hub heights of turbines, and deploying projects far-offshore with better wind

<sup>12</sup> The average turbine rated power between 2016 and 2020 was roughly 9.5 MW [10]. GE Renewable Energy introduced 12 MW turbine platforms in 2020, with planned deployments in 2023–2025 [95]. Siemens Gamesa announced 14 MW turbine platform in 2020, with commercial use expected by 2024 [96]. Vestas announced 15 MW offshore platform and serial production is expected for 2024 [97].

<sup>13</sup> The learning-by-doing effect is expected to specifically crucial for floating wind as multiple foundation designs exist currently in the prototype stage and a design convergence is essential to initiate mass production of components and standardize necessary technological modifications (e.g., turbine control systems, O&M strategy, installation techniques).

<sup>14</sup> Specific power rating of wind turbine: Specific power rating of wind turbine relates its capacity to the swept area of its rotor in terms of Watt per square meter. Refer to [98] for more details.

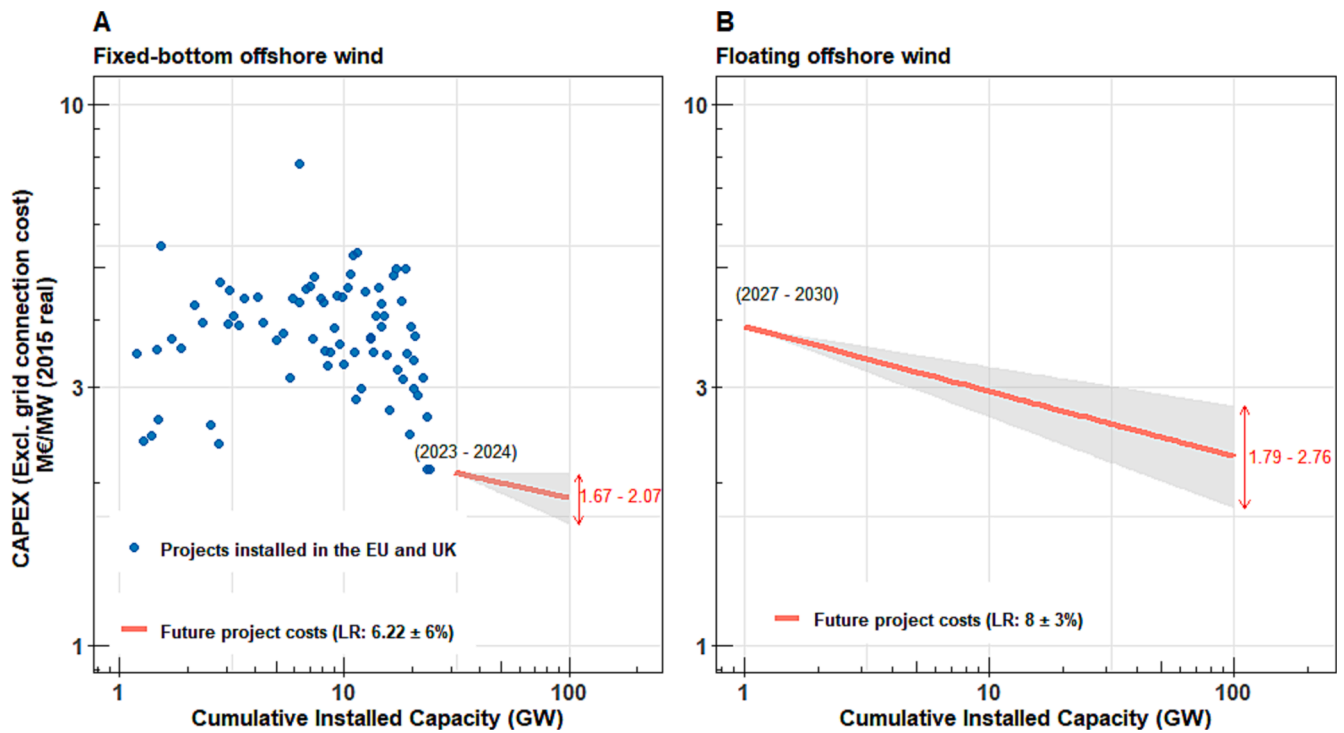


Fig. 3. CAPEX outlook of offshore wind. a) FBOW CAPEX developments projected from 31 to 100 GW cumulative capacity. b) Floating wind CAPEX developments projected from 1 to 100 GW cumulative capacity.

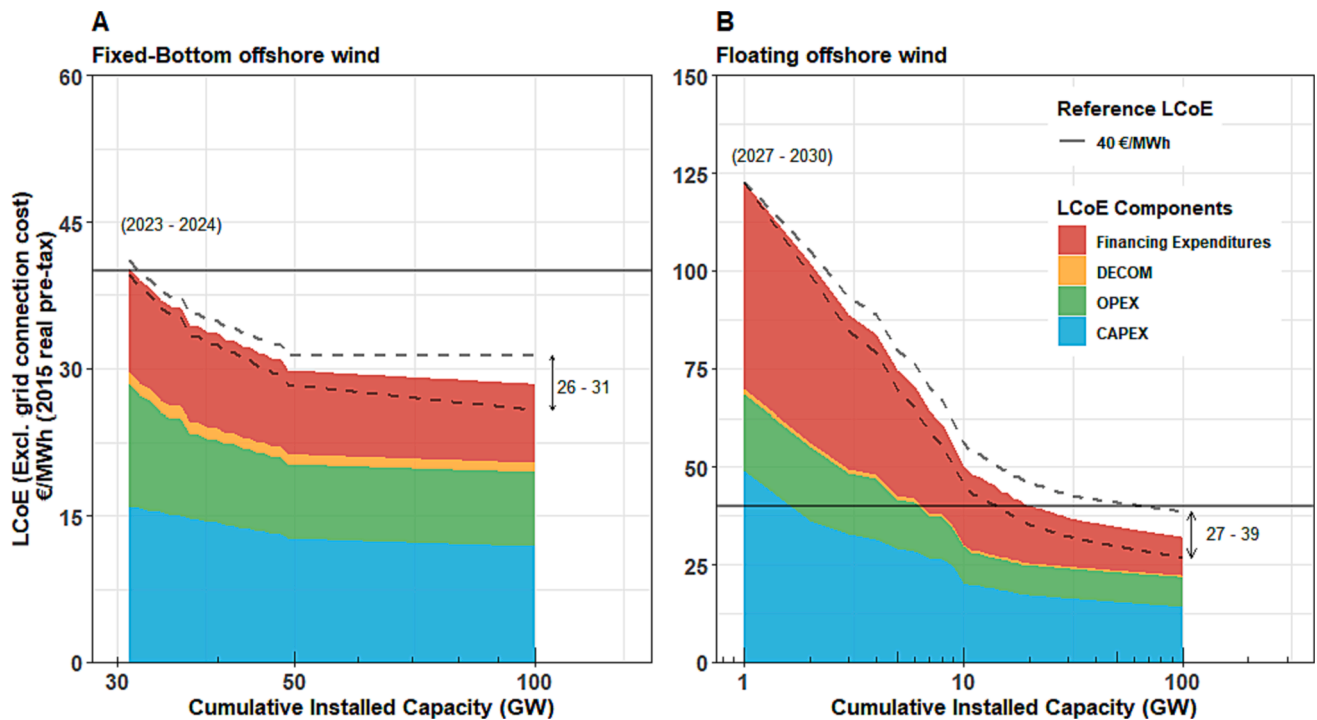


Fig. 4. LCOE outlook for offshore wind. a) FBOW LCOE developments projected from 31 to 100 GW of cumulative capacity. b) floating wind LCOE developments projected from 1 to 100 GW of cumulative capacity. The dotted lines in the figure indicate the uncertainty range of the LCOE development trajectory (upon considering CAPEX LR interval estimates, 95% confidence interval).



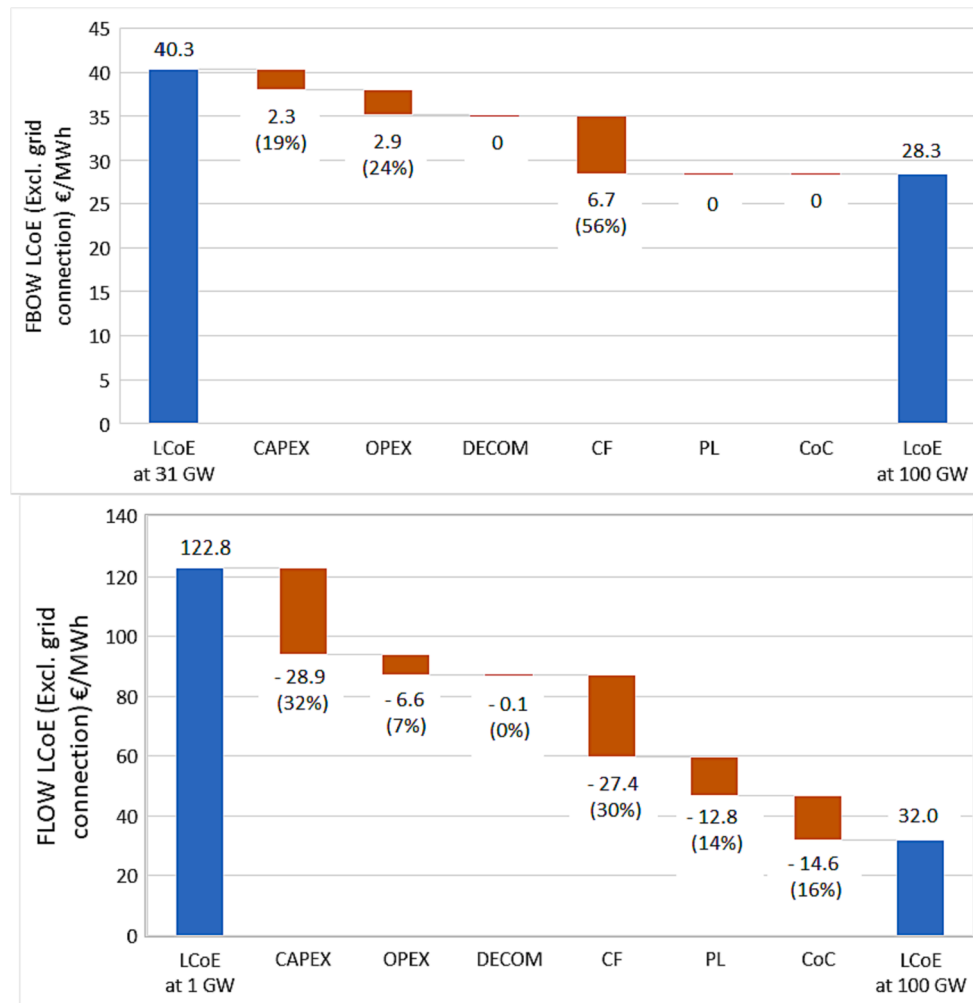


Fig. 5. Impact of individual factors contributing to the LCOE reduction. The figure presents the base case cost reduction (i.e., excluding uncertainty range) considered for FBOW and floating wind in Fig. 4.

resources will further improve the wind farm's capacity factor<sup>15</sup> (see Appendix H). The turbine availability for floating wind will be lower in its early commercial deployments due to its excitations at higher wind speeds and wave conditions [77]. However, with experience, improved operation controls will be implemented to diminish these effects for future deployments and existing projects. In overall LCOE development, the capacity factor improvements contribute to 6.7 €/MWh reduction (56 %) for FBOW and 27.4 €/MWh reduction (30 %) for floating wind. As floating wind is expected to be deployed in far-offshore regions with better wind resources, where FBOW is unsuitable, the increased capacity factor resulting from turbines with higher rated power plays a more vital role in offsetting floating wind's higher CAPEX (Fig. 5). **3) Project lifetime:** Extending the wind farm projects' economic lifetime increases the long-term profitability for the developers [78]. For FBOW, a project lifetime of 30 years is assumed due to its existing experience and improved understanding of its operation and performance. Hence, there is no further contribution from the project lifetime factor. For floating wind, a project lifetime of 20 years was assumed for the first GW, 25 years from 1 to 10 GW, and 30 years after 10 + GW cumulative capacity (see Appendix K). This increased project economic lifetime resulting

from operational experience gain will result in a 12.8 €/MWh reduction (14 %) in the overall LCOE development of floating wind. **4) Cost of Capital (Cost of Capital):** For capital-intensive technologies such as offshore wind, the discount rate (cost of capital) plays a major role in LCOE [79]. The pricing of FBOW is already competitive in its mature markets due to its experience, market competition, availability of low interest rates, and prevailing regulatory settings [80,81]. Hence, there is no LCOE reduction expected from this factor. It is to be reminded here that exogenous market conditions like general interest rates, which are considered to be not changing in this study, can alter the influence of Cost of Capital for FBOW (refer to Appendix G). For floating wind, on the other hand, a higher cost of capital is expected for early commercial deployments because of its limited track record, see Fig. 6 (b). However, with experience from the deployments and availability of favourable market conditions (e.g., subsidies and long-term market visibility), the financing expenditures are expected to decline to similar levels observed for FBOW, as shown in Fig. 4. In overall LCOE development, the Cost of Capital factor contribute to 14.6 €/MWh reduction (16 %) for floating wind.

Lastly, to map the LCOE developments through time, deployment projections from the literature and market diffusion process modelled with S-curve are applied, see Appendix M for more details on deployment projections. For FBOW,  $96 \pm 9$  GW of cumulative capacity could be deployed by 2030 in the EU and UK, with LCOE reaching  $28 \pm 3$  €/MWh; see Fig. 7 (a). For floating wind, considerable uncertainties exist on future deployments. 26–130 GW of cumulative capacity is

<sup>15</sup> Technological improvements do improve the energy capture and increases the capacity factor. Nevertheless, the better wind resources resulting from the site-characteristics is observed to be a major driver for higher capacity factors (as shown in Appendix H).

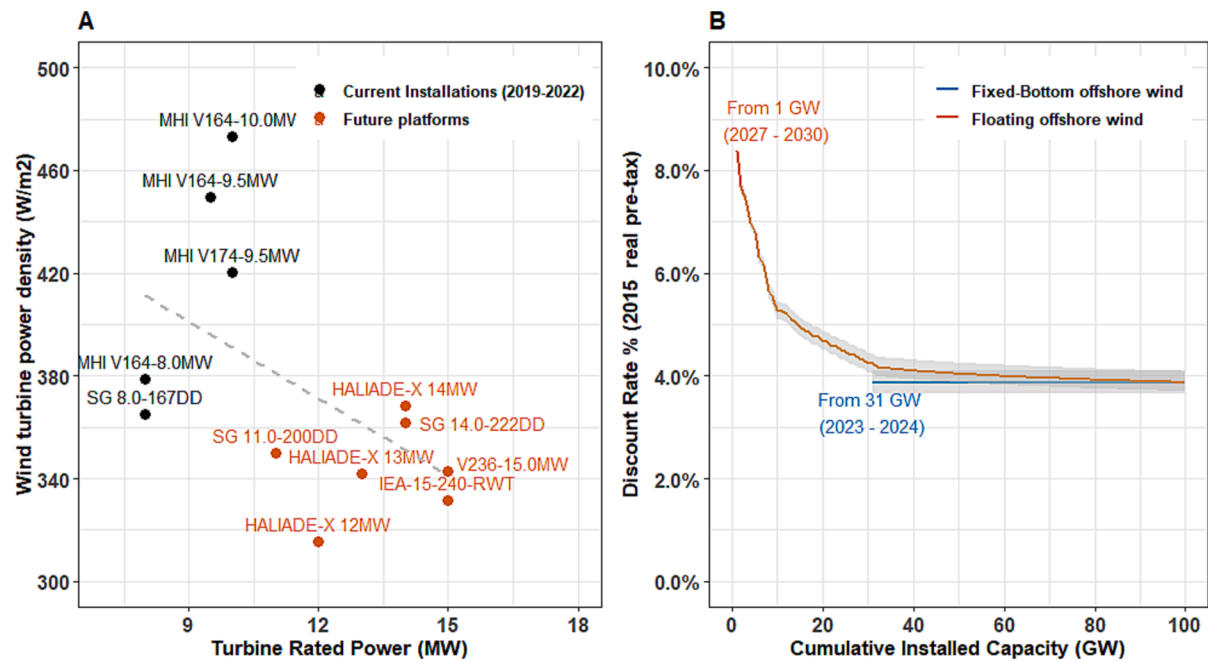


Fig. 6. Drivers of technological learning of offshore wind. a) Power density developments for offshore wind turbines. The dotted line indicates the trend in the reduction of wind turbine power density. b) Expected discount rate developments for FBOW and floating wind, based on increasing cumulative capacity (not time). The shaded region in the figure indicates the uncertainty range of the discount rate developments; see Experimental Procedures and Table S6 for further details.

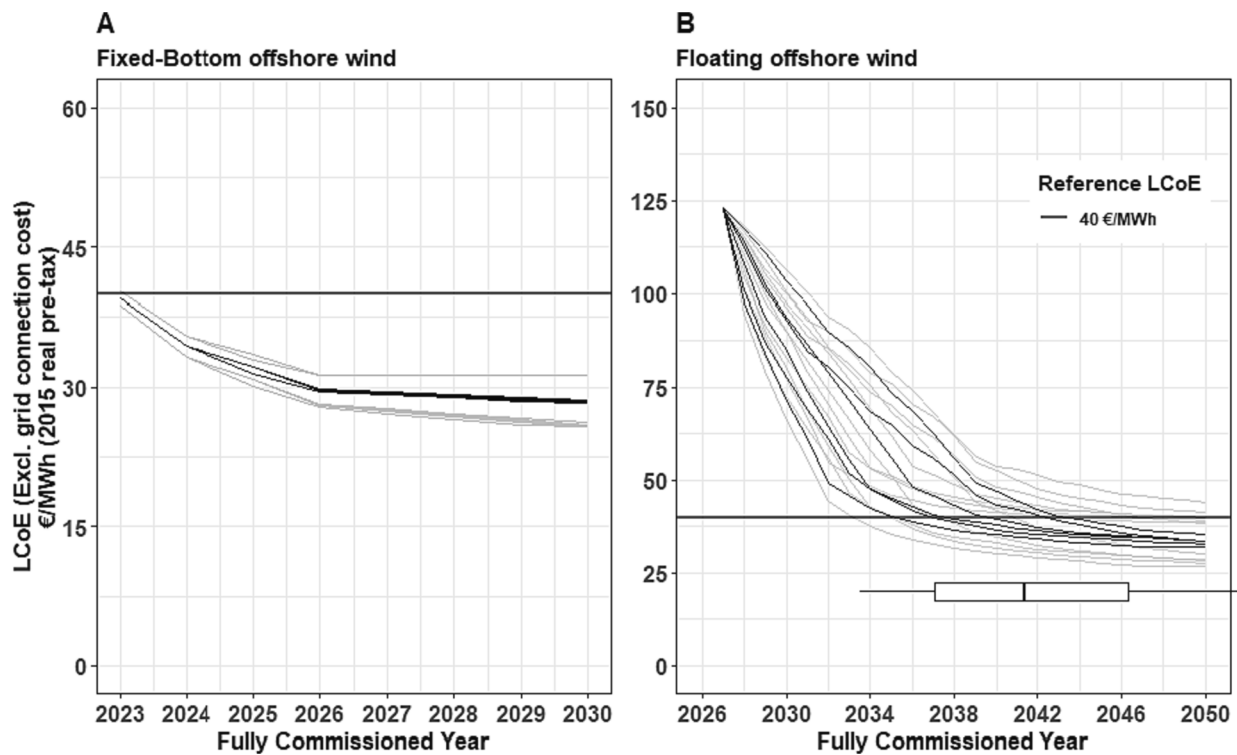
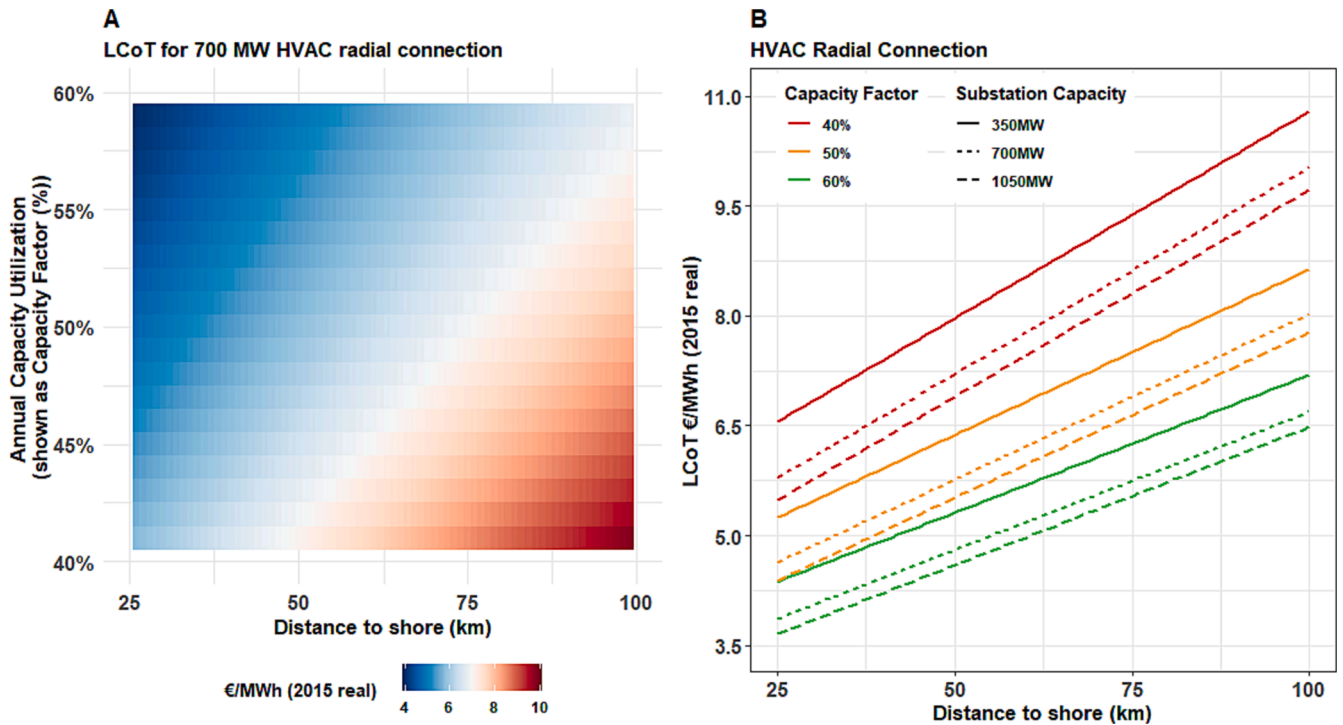


Fig. 7. Mapping LCOE developments for offshore wind technology over time. A) Fixed-Bottom offshore wind LCOE developments projected from 2023 to 2030. B) Floating offshore wind LCOE developments are projected from 2026 to 2050. Breakeven periods, where floating wind achieves 40 €/MWh, observed from the deployment scenarios are summarized using a box plot.

foreseen by 2050 in the EU and UK, with LCOE reaching 27–44 €/MWh; see Fig. 7 (b).

Moreover, we have also compared our long-term cost assessments of offshore wind with existing literature; see Appendix N. For floating wind, the initial costs illustrating the near-term developments towards

2030 are observed to have been over optimistic in literature. However, in long-term, the floating wind costs estimated in this study are in line with values from existing literature. The differences in the near-term LCOE are mainly arising from the lack of component-level cost and performance assessment, in existing literature e.g., limited



**Fig. 8.** Grid connection cost for offshore wind. a) LCoT cost matrix estimated for 700 MW HVAC radial connection, as a function of distance to shore and capacity factor. b) Outlining the impacts of distance to shore and upscaled transmission capacity on LCoT.

understanding of the impact of bigger turbines on cost and performance (Appendix H). For FBOW, it is observed that LCOE developments in the literature are underestimated. This case is possibly due to assuming a static financing conditions for long-term cost assessments in existing literature, which does not reflect the realistic development in the markets as the cost of financing decline with technology maturity.

#### Grid connection cost for offshore wind

The grid connection costs were estimated separately as Levelized Cost of Transmission (LCOT) to illustrate the influence of site characteristics on offshore wind technology costs (see Experimental Procedures). Fig. 8 (a) shows the LCOT for 700 MW High Voltage Alternating Current (HVAC) radial connection as a function of capacity factor and distance to shore. Fig. 8 (b) then outlines the increasing LCOT for HVAC radial connections with a distance to shore up to 100 km and the impact of scale effects. Beyond 100 km, and with increased project capacities (>1 GW), the HVAC systems require additional components like reactive power compensators to reduce the power losses in the export cables [82,83], thereby increasing LCOT for longer distances steeper than the trend shown in Fig. 8 (b). High Voltage Direct Current (HVDC) technology is expected to become competitive in such cases, as it is efficient in long-distance bulk power transfers (expensive converter station, but lighter cables, lower losses, and no reactive energy) [84]. Ruijgrok et al. estimated LCOT for radial connections and described the competitiveness of HVDC for long distances. However, the upscaling effects were not considered in their analysis. The study showed the LCOT for HVDC radial connection with a 325 kV DC cable (at 30 m water depth, assuming fixed-bottom foundation) for distance to shore between 100 and 300 km in the range of 13–19 €/MWh, compared to 11–24 €/MWh in the case of HVAC with a 220 kV AC cable [28].

Besides increasing LCOT with distance to shore, increased deployment targets and rapid installation rates of offshore wind add complexity to integrating them efficiently onto the onshore grid. The complexities include rising spatial constraints for offshore energy infrastructures (subsea cable routes [85]) and the need for long-duration

flexibility to manage a high share of renewables [86]. Studies have shown that an integrated offshore grid, with transmission assets serving as grid connection for wind farms and as interconnector, provides more cost advantages through economies of scale, reduces overall environmental impacts, and increases energy security compared to separate radial connections [28,87]. e-Highway2050, a project funded by the European Commission (EC) to analyze the expansion of the pan-European electricity grid, forecasted 336 GW of net transfer capacity (cross-border interconnectors) by 2050 in its 100 % Renewable Energy System scenario. This estimate is roughly a four-fold increase from the capacity in 2020 (90 GW), and the EC has already pointed out the stalling of interconnector expansion due to existing regulatory barriers. In the event of continued delays, CO<sub>2</sub> emissions, variable electricity generation costs, and renewable energy curtailment are expected to increase in the energy system [88]. Moreover, Power-to-Gas and Gas-to-Power conversion routes (e.g., hydrogen) that can re-use existing onshore and offshore gas infrastructures and provide long-duration time-shifting flexibility are regarded as promising solutions to reduce offshore wind power curtailments and increase the utilization of transmission systems [87,89]. These challenges and proposed solutions indicate that the integration routes for future large-scale wind farms will be more complex and integrated, especially if the ambitious deployment targets set for offshore wind are to be achieved efficiently. The development of such an integrated grid infrastructure would require coordinated long-term system-level planning, which is currently absent [90].

#### Conclusions

Based on the long-term cost assessment presented in this study, five major conclusions for the offshore wind industry, policymakers, and researchers are discussed below.

First, FBOW is well-established in its mature markets and has reached 40 €/MWh (excl. grid connection cost) by 31 GW of cumulative capacity (2023–2024). floating wind, on the other hand, is an emerging variant but shows significant development potential. floating wind could achieve the same progress (40 €/MWh, excl. grid connection cost)

by deploying roughly 21 GW of cumulative capacity, requiring €44 billion of learning investment. When the LR uncertainties of floating wind are considered, the breakeven capacity in reaching 40 €/MWh (excl. grid connection cost) ranges from 14 to 64 GW, requiring 34–70 billion € of learning investment. For comparison, in 2017 alone, the EU-27 countries and the UK provided €65 billion of subsidies for renewable power generation, including tax expenditures and direct and indirect transfers to compensate price-gap (1 US\$ = 0.83 €) [66]. This result suggests that providing the learning investments for floating wind in the form of subsidies (e.g., Contracts for Difference, Feed-in-Tariff) through strategic allocation among several countries (preferably in a global context) could fasten the technological progress of floating wind.

Second, our assessment shows that several factors influence offshore wind technology's cost developments. These factors are categorized into three levels to highlight the multi-dimensional policy effort required to continue the growth of FBOW and successfully commercialize floating wind; see Appendix O. 1) Technology-specific factors need to be advanced through dedicated R&D, such as for lighter turbine blades and towers, testing facilities, and O&M automation. As capacity factor improvements are expected to play a significant role in both FBOW and floating wind developments (see Fig. 5), R&D efforts towards unit-upscaling, wind farm availability improvements are crucial. 2) Exogenous factors need to be influenced through policy measures that can create a favourable marketplace for the technology deployments, e.g., innovative funding mechanisms that de-risk emerging innovations and increases deployments [91], streamlining permitting procedures [7]. 3) Learning in the technology value chain is also crucial to avoid bottlenecks in realizing the ambitious deployment targets set by the governments. This effect can be influenced by encouraging the development of joint projects (e.g., OEM taking a minority share in projects [7]), passing on the know-how knowledge, and clear communication of technology roadmaps to inform the supply chain about market expectations.

Third, as offshore wind technology costs are expected to decline through learning, grid connection will become a significant cost component. We determined that a complex integrated offshore grid would be needed to overcome the increasing spatial constraints and effectively integrate large-scale offshore wind farms onto the onshore grid. The development of such a network demand coordinated long-term system-level planning. However, several barriers, including cross-border regulatory differences, uncertainty in stakeholder responsibilities, and the absence of a multi-actor governance structure, hinder the realization of such a network [90]. For example, the average duration of an electricity transmission PCI (Projects of Common Interest, e.g., inter-connectors) in the EU from planning approval until commissioning is about 10 years [92]. Nevertheless, those barriers can be overcome if stakeholders make a timely and concerted effort, as seen in Kriegers Flak – Combined Grid Solution project, a grid network in the Baltic Sea connecting Denmark and Germany via two offshore wind farms [93]. Several grid solutions similar to Kriegers Flak are needed to effectively realize the ambitious deployment targets, demanding policymakers to focus on long-term system-level planning.

Fourth, emerging technologies spatially diffuse into new markets as they mature with experience and observe cost reductions in their core markets. Several new countries have already shown increased interest in utility-scale deployments of FBOW. This effect is also expected for floating wind. Our results and insights on offshore wind cost developments have global implications. Nevertheless, future studies extrapolating developments in a new market should be cautious about the technology- and market-level differences. For example, the availability of technology (turbines and installation vessels) and local learning (sourcing of electrical components, manufacturing capabilities, and installation practices) can introduce differences in technology's CAPEX, similar to solar PV. Similarly, market differences, including competition, commodity prices, interest rates, site characteristics, and regulatory settings, can affect the final energy cost in a particular country [7,94]. Realizing these differences and their impacts will benefit

the policymakers in designing targeted policy actions to overcome the barriers and effectively stimulate offshore wind's technological progress.

Lastly, by leveraging the merits of bottom-up engineering cost modelling, we overcame the limitations of the experience curve approach in describing the cost drivers and impacts of site characteristics on offshore wind technology costs. However, long-term cost assessment accuracy depends on the LR uncertainties and assumptions applied in bottom-up cost modelling, affected by factors including data limitations, commodity price variations, market shifts [72]. Future studies should incorporate any further growth of offshore wind deployments and price developments in their mature and new markets, floor cost estimation (minimum technology cost estimated using material and production costs alone [72]) in their analysis to account for these changes, and update the cost assessment. It is also suggested that studies apply the cost outlook provided here and perform system-level modelling with increased spatial granularity to assess potential integration pathways, bottlenecks, and infrastructure and investment needs for offshore wind deployments in future energy systems.

### CRedit authorship contribution statement

**Srinivasan Santhakumar:** Conceptualization, Methodology, Software, Formal analysis, Investigation, Visualization, Writing – original draft, Writing – review & editing. **Clara Heuberger-Austin:** Conceptualization, Methodology, Writing – review & editing, Supervision. **Hans Meerman:** Conceptualization, Methodology, Writing – review & editing, Supervision, Project administration. **André Faaij:** Conceptualization, Methodology, Writing – review & editing, Funding acquisition, Supervision, Project administration.

### Declaration of competing interest

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

### Data availability

The dataset can be found in <https://zenodo.org/records/4706023>.

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### Appendix A. Supplementary data

Supplementary data to this article can be found online at <https://doi.org/10.1016/j.seta.2023.103545>.



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