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An analytical cost model for co-located floating wind-wave energy arrays

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ABSTRACT

Offshore wind and wave energy are co-located resources, and both industries are driven to reduce cost of energy. Due to the maturity of offshore wind technology and continued growth of both offshore floating wind and wave energy converter (WEC) technology, there is new opportunity to combine wind and wave technologies in the same leased ocean space through co-located array development. Co-location is projected to have synergistic effects that reduce direct and indirect costs for developments, but few of these synergistic effects have been quantified, and many have not been related to cost. Moreover, there is currently no cost model that incorporates these effects. In this study, we address this need by developing a cost model that represents co-located array developments, particularly for floating offshore wind and WEC technologies. We exemplify the use of this cost model through a case study. Results suggest floating wind-wave co-located arrays are advantageous to WEC-only or floating wind-only. These results are contingent on our assumptions regarding cost categories and values included in the model and also the power production and reliability of the devices. We conclude by identifying research gaps and uncertainties to be minimized in future improvements of the model.

1. Introduction

In the offshore renewable energy industry, offshore wind is the only technology that has reached global commercial installation. In 2017, global offshore wind capacity reached 18,814 MW, with 3.9 GW of combined capacity for projects expected to achieve financial investment decision (FID) in 2018 [1]. Although Europe began installation two decades ago and still contributes half the global capacity, emerging markets in Asia and North America are indicative of increasing global adoption. Further cost reduction remains critical for offshore wind energy to remain competitive and continue to grow in global implementation.

In areas where fixed-bottom offshore wind structures are infeasible, floating offshore wind platforms could provide access to plentiful resource further offshore in deeper waters. Moreover, floating offshore wind turbines are potentially economically competitive with (and in some cases, even advantageous to) fixed-bottom offshore wind turbines in deep waters [2]. With the first grid-connected floating offshore wind array recently installed [3], there is renewed motivation to rapidly reduce floating offshore wind array costs and improve power production.

Although wave resource is plentiful, wave energy technology is still at an early stage of development in comparison with offshore wind technologies. However, offshore wind and wave resources often coexist in the same locations, and the technologies share similarities that could provide opportunities for mutual benefits.

Co-location of offshore wind turbines and wave energy converters (WECs) in the same leased ocean space exploits these similarities to improve power development and lower costs of the array. However, not enough is known about the costs of co-location to provide a quantitative conclusion to developers and investors about its potential economic advantages. Accurate levelized cost of energy (LCOE) estimations for co-located arrays could enable commercial installation for these novel technologies as they try to prove credibility, gain industrial experience, and compete with cheaper forms of renewable energy.

The objective of this research is to provide a means of quantifying the economic benefits of co-location. To achieve this, we aim to identify opportunities for mutual benefit and incorporate them into an analytical cost model. We propose an analytical cost model for the purposes of applying optimization techniques in the future, such as those used in fixed-bottom [4–7] and floating [8] offshore

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wind technology, as well as with WEC technology [9,10] applications. Building an analytical cost model that can be used as an objective function for these optimization schemes will allow for further increases in cost competitiveness of these technologies through optimization of system parameters.

This study is divided into six sections. First, we review existing literature on co-located arrays to highlight opportunities for shared costs, as well as future areas of research that are needed to address shared-cost uncertainties. Then, we discuss the cost model structure, along with the methodology for developing each cost component. Lastly, we apply the cost model to a theoretical co-located floating wind-wave array to compare it to current offshore renewable energy developments.

2. Previous research

Although co-located wind-wave arrays are subjects of more recent study, the body of literature that encompasses co-located arrays (wind-wave and otherwise), hybrid platforms, and cost information for offshore wind and wave energy is extensive. Therefore, this literature review will focus on literature that influences our understanding of potential shared costs of co-located floating wind-wave systems, and cost-models available for analogous systems. Those wanting a broader review of co-located array technology can find one here: [11].

2.1. Opportunities for shared costs

Co-located wind-wave arrays have been studied since the mid-2000s (the earliest paper cited here is 2006), but has recently become more popular in published literature, encouraged by a group of EU-funded projects [12–15]. Shared cost opportunities based on this technical literature can be categorized by their influence in phases of a co-located array project, defined as pre-installation, implementation, operation, and decommissioning phases [16]. The following section describes shared costs considered in the development of the present cost model.

Pre-installation costs include development and consenting costs, or costs incurred from developing a concept to the point of financial close or commitment to build. During this phase of the project, environmental implications (such as site characterization or permitting) and social implications (such as stakeholder engagement processes, infrastructure planning, or site selection) are necessary to the project, and can be achieved through coordinated efforts between offshore wind and wave energy developers. Although not all costs can be shared (for example, different permitting might exist for a bottom-mounted WEC than a fixed-bottom offshore wind turbine), many of the most expensive components [17] can be shared. Similarly, social factors that can halt a project [18,19] (for instance, due to unsuccessful stakeholder engagement, or inability to finalize a Power Purchase Agreement) are often common between offshore wind and wave energy projects. The cost of stakeholder engagement is highly situational, thus it follows that the incremental costs between developing a co-located array versus a wind-only or wave-only array is also highly variable. Consequently, savings from co-location may be negligible, as we assume in this cost model. Therefore, costs from wind- and wave-only arrays are used as a proxy for co-located arrays. An area of needed future work is investigating the social and political differences between co-located wind-wave installations, and wind- or wave-only installations.

Implementation costs include costs incurred while designing, building, transporting, storing, installing, and commissioning the devices, foundations, mooring, anchoring, and electrical infrastructure. Depending on the device design, WECs and wind turbines can share many of these costs. Grid infrastructure, for instance, remains one the highest costs in both offshore wind and wave energy developments. Sharing cabling and other electrical infrastructure costs can lower cost per unit energy. Likewise, common structural components such as foundations or mooring can be shared in some cases. In this paper, turbines and WECs are assumed not to share these structural components. However, it is important to note that each structure will have its own effect on the hydrodynamics and sediment of the site, which can affect devices downstream or downwind. Engineering analysis is required in this area to understand what structural costs can be shared in these co-located systems, and how that sharing may lead to hydrodynamic or sediment differences in the site. Lastly, shared logistics resources and personnel are not only high cost, but can delay progress in installation (and O&M processes and decommissioning) due to availability or proximity to the project. By sharing the same logistical resources, costs for these services can be shared, and downtime of devices waiting servicing can be minimized.

Once in operation, a co-located array has two means to exploit shared opportunities: through operational expenditure (OPEX) reduction, and through power production enhancement. OPEX includes costs that start after the point of issue of a take over certificate, and are continued until decommissioning of the devices. As mentioned, sharing logistics provides an opportunity to share costs during O&M. Specific to O&M, the longer a device is out of service or performing sub-optimally, the longer it is temporarily not producing power. Moreover, when WECs are placed peripherally along the offshore wind farm facing the dominant wave directions, the WECs will decrease the wave height in their lee [11,20–23]. This effect was originally termed the Shadow Effect [24], and if layouts are arranged to capitalize on this effect, wave heights can be decreased within the offshore wind farm. Decreased wave heights thereby increase the accessibility of the wind farm so that O&M personnel can have more and longer weather windows, as well as decrease downtime of the devices.

In a co-located array more energy is being captured because more devices are added to the same ocean space, which results in greater power production per unit area [25–27]. Additionally, different resources are being converted, so while adding a wind turbine to the back row of a wind turbine site might result in sub-optimal performance of that added turbine due to wake effects, adding a wave energy converter should not affect the wake interactions of the wind turbines significantly. System-balancing costs can be decreased due to wave energy resources being more predictable and less variant than wind [28–30]. In addition, because of variations in wind and wave resource characteristics (such as wave peaks lagging behind wind peaks [22] power quality is enhanced by smoothing effects. In fact, grid integration can be optimized in co-located systems by layout of the array, varying ratios of devices, and site selection [29–36].

Finally, decommissioning costs include the removal of equipment and materials after the useful life of the devices. Decommissioning costs mirror implementation costs for many components, and have opportunity for shared costs in permitting for removal processes and logistics cost.

2.2. Economic models

Four cost analyses have been used to inform how floating offshore wind and wave technologies can be combined from an economic perspective, through analyses of co-located arrays [37], hybrid wind-wave platforms [38], and floating offshore wind platforms [39–41]. We used these cost models to inform which cost categories to include, particularly concerning shared costs, lifecycle costs, and costs specific to floating offshore wind platforms and

wave energy converters. The resulting cost model uses the structure of previous lifecycle cost models, but amends the cost categories to represent those shared costs of a co-located floating offshore wind and wave energy array.

The first cost model that informed our incorporation of shared costs for co-located arrays is that by Astariz et al. [37]. They calculate levelized cost of a co-located array at the Alpha Ventus wind farm and a theoretical, peripherally distributed WaveCat [42] array with a 20-year lifespan. A discounting method was used to calculate LCOE, which was a function of layout (number of devices, configuration, orientation, and space between devices), and varied given an applied learning rate (a decrease in cost given increased global installed capacity) of 0.85%, 0.87%, and 0.90%. This study showed that the LCOE of co-located arrays is strongly influenced by learning rate and WEC array layout. Costs included preliminary costs, capital costs, O&M costs, and decommissioning costs. Engineering tasks and licenses comprised preliminary costs and capital costs included those incurred by the WEC system, as well as the electrical system. WEC system costs were broken down by component; WEC materials based on a 1.2 MW WaveCat [42], the power-takeoff (PTO) system, mooring, and installation. The electrical system included the medium voltage inter-array cable, the high voltage export cable, and the offshore substation. Both scheduled and unscheduled maintenance was accounted for in O&M costs, as well as insurance and 'other costs', which include leasing, administration, and miscellaneous fees. Decommissioning costs were assumed to be 0.75% of the initial costs.

Astariz et al. [37] use cost sharing opportunities throughout the cost model, particularly in O&M costs. In preliminary costs, the authors assumed a site characterization and licensing cost based on existing WEC cost literature, and assumed all site characterization and permitting from the offshore wind farm had already been completed. In addition, the authors assumed common design elements, such as the offshore station and the export cable could be the same for both Alpha Ventus and the WEC array. These cost sharing opportunities resulted in 12–14% reductions in capital costs. O&M costs were reduced by 12% from sharing of personnel, repair vessels, and access. Cost sharing associated with installation and decommissioning resources and services was not included because the Alpha Ventus was assumed to already exist, with later installation of WECs. If the WECs and wind turbines in a co-located array were to be installed at the same time and have the same lifespan, they would also share these costs. Enhanced power production was also calculated, resulting in a LCOE of 288–302 €/MWh, a 55% reduction compared to a wave-only array, and a 200% increase compared to a wind-only array.

Although Astariz et al. [37] use a bulk learning rate and have proven its impact on LCOE, we do not incorporate learning rate into the present cost model. Learning curves require assumptions to be made about starting costs, learning rates, and capacity at which sustained cost reductions occur, and are also sensitive to small variations in these values [43]. While some factors influencing learning curves can be calculated for co-located systems (such as influence of economies of scale effects), others have associated uncertainty that has not yet been quantified (such as those effects associated with co-design of these systems). As co-located arrays become more studied, exploring the relationship between learning curves and co-location will become an area of necessary work.

A cost model methodology was also developed by Castro-Santos et al. for a hybrid wind-wave platform, rather than a co-located wind-wave array [38]. Using a life cycle cost approach, they include seven cost categories: concept definition, design, development, manufacturing, installation, O&M, and decommissioning. Concept definition includes the costs of feasibility studies, taxes and other legislative costs, and environmental measurements to be used in farm design. Design, development, manufacturing, and installation costs are noted for each device subsystem: the device, the floating platform, moorings, anchors, and electrical system. O&M costs include insurance, business, administrative, and legal fees, as well as preventative and corrective maintenance. These maintenance types include costs associated with the transport, material, and labor costs of each subsystem. Lastly, decommissioning costs included vessel and personnel costs for removal and cleaning of the energy site, and included costs for dumping components and negative costs (income) for scrapping components when appropriate, as indicated in their analysis per subsystem.

Two papers, first by Castro-Santos and Diaz-Casas and later by Myhr et al., use a similar life cycle cost approach to calculate costs for floating offshore wind platforms [40,41] resulting in similar cost categories to that used in Castro-Santos et al.'s cost analysis of a hybrid wind-wave platform. The costs that are specific to floating offshore wind technology have been used to develop the cost model in this study. Moreover, the structure of the cost model is relevant and is adapted for this paper.

3. Cost model development

The methodology proposed relies on generic WEC structure breakdown and project phases to define cost components [16]. This methodology uses a life cycle cost approach and covers the full device life cycle costs of co-located floating wind-wave arrays [38,40,41]. We use cost of energy (LCOE) in this study as it is a prevalent measure by which many renewable energy technologies are compared [44,45]. Here, LCOE is measured in $USD/MWh in real terms, and is representative of the break-even cost of electricity (no revenue to the utility). Although the presented cost methodology can be applied to any location, the LCOE measure is context-specific, as reflected in the case study shown in this paper.

The LCOE is equal to the costs (C_t) incurred throughout the lifespan (t) of the co-located array, divided by the power produced (O_t) in that lifespan (n).

$$LCOE = \frac{PV(Costs)}{PV(Output)} = \frac{\sum_{t=0}^{n} C_t \Big/ (1 + r_{discount})^t}{\sum_{t=0}^{n} O_t \Big/ (1 + r_{discount})^t} \tag{1}$$

PV is present value, obtained by a discounting method with a given discount rate ($r_{discount}$). The discount rate incorporates inflation from a Nominal Discount Rate to convert it to a Real Discount Rate (meaning all costs are constant $USD) [44]:

$$r_{discount} = \frac{r_{borrowing} + r_{inflation}}{1 - r_{inflation}} \tag{2}$$

Here, $r_{borrowing}$ is the borrowing rate for a loan and $r_{inflation}$ is the inflation rate. In previous literature, a 12% discount rate was used [46], while others calculated discount rate given a 10% borrowing rate [40,44], 5% [44], or 2.5% [40] inflation rate. In this study, we will use a 10% borrowing rate and a 2% inflation rate.

The costs incurred over the lifecycle of the co-located array include the cost of pre-installation ($C_{Pre-installation}$), implementation ($C_{Implementation}$), OPEX (C_{OPEX}), and decommissioning($C_{Decommissioning}$) phases of the project:

$$C_t = C_{Pre-installation} + C_{Implementation} + C_{OPEX} + C_{Decommissioning} \tag{3}$$

These costs, along with the methodology for determining power

produced by the co-located array, will be further described in the following sections.

3.1. Pre-installation

Pre-installation costs include costs associated with feasibility studies; site selection, characterization, and monitoring; permitting; stakeholder engagement; and array design.

$$C_{Pre-installation} = C_{Feasibility} + C_{Site} + C_{Permit} + C_{Engagement} + C_{Design} \quad (4)$$

Information about pre-installation costs is context-specific and is one of the costs to which the overall project cost is most sensitive [44]. Most economic analyses either do not include pre-installation costs [47–51], or include a conservative estimate for other costs with capital expenditure (CAPEX), but do not fully describe how these other costs are being calculated. For instance, pre-installation costs have been estimated to be 12% of CAPEX [44,50] or 2.45–2.65 m€ total [37]. Pre-installation costs were sub-categorized for a hybrid platform and were estimated at 100,000 € for market studies, 144,262 € for legislative costs, and 3–5 m€ for farm design, dependent on the size of the farm [38]. A current construction project, Pacific Marine Energy Center's South Energy Test Site (PMEC SETS) is investing $5 million in design and permitting in the second phase of the project, which does not include money spent on pre-installation costs during the first phase of the project [52]. This cost is inflated due to the mission of the research facility (non-regulatory research is being conducted, which incurs higher prices), but the project is also smaller than most commercial installations. Costs due to viewshed alteration were found to be, on average, 3% of the project cost [38]. During early phases of development in the US, these pre-installation costs are significant to total project cost, but will most likely be highly influenced by learning rates and public perception. Table 1 highlights preliminary cost categories and values used in the literature.

In this study, we use pre-installation costs based on a 500 MW floating wind site [40]. Although we recognize that the rated capacity of the co-located floating wind-wave array is lower than 500 MW, most of the costs included are not dependent on site capacity. We did not include permitting, public engagement, and viewshed cost explicitly, due to lack of data, and site-specific variation. For example, more stakeholder engagement funds might be required in a community unfamiliar with offshore renewable energy. Likewise, permitting can pose a barrier to implementation in some communities, but the permits required and their costs are uncertain for newer technologies in this industry.

Table 1
Pre-installation costs.

Ref.	Description	Cost
[37]	"Engineering tasks and licenses" in a co-located wind-wave array	570,000 €
[38] [a]	Feasibility study	100,000 €
	Legislative factors	474,951 €
	Design for a hybrid wind-wave platform	5,141,382 €
[41]	Feasibility study, legislative factors, and farm design for a floating wind turbine	6.79 m€
[40]	Environmental, met station, and sea bed surveys, front-end engineering and design, project management and development services of 500 MW floating wind turbine	104,106 k€ ±10%
[53]	Viewshed costs	3%
[54]	Siting and Permits	2% of IC
	GHG Investigation	0.5% of IC

[a] In this paper, costs in Ref. [38] refer to the costs of the 105.40 MW Poseidon array in the Aguaç adoura case study.

3.2. Implementation

The cost of implementation includes the cost of designing, building, transporting, storing, installing, and commissioning all subsystems of the site. For our purposes, this will include WEC and wind turbine structures, mooring, anchors, and a shared electrical system.

$$C_{Implementation} = C_{Design} + C_{Build} + C_{Transport} + C_{Storage} + C_{Install} + C_{Commissioning} \quad (5)$$

Design, build, and transport costs are considered here to be separate for WECs and turbines, although realistically, there could be coordinated efforts that share costs. Therefore, the cost of designing, building, and transporting the co-located devices is the sum of these costs for WECs and turbines.

$$C_{Design} = C_{Design_{WEC}} + C_{Design_{Turbine}} \quad (6)$$

$$C_{Build} = C_{Build_{WEC}} + C_{Build_{Turbine}} \quad (7)$$

$$C_{Transport} = C_{Transport_{WEC}} + C_{Transport_{Turbine}} \quad (8)$$

Shared cost opportunities are considered for storage costs, installation costs, and commissioning costs.

The costs per subsystem and cost component that are used in

Table 2
Capital costs.

Reference	Description	Cost
[37]	Device	9.18 m€/WEC
	PTO	6 m€/WEC
	Mooring	10,370 €/WEC
	Installation	0.3 m€/WEC
	Inter-array cable	380 €/m
	Offshore station	2.95 m€/WEC
	Export Cable	750 €/m
[38]	Design/Development	245,371 €
	Manufacturing	
	Device	94,078,680 €
	Platform	64,728,921 €
	Mooring	6,137,841 €
	Anchors	6,728,996 €
	Electrical System	10,582,566 €
	Installation	94,078,680 €
	Device	510,000 €
	Platform	59,165,502 €
	Mooring/Anchors	708,708 €
	Electrical System	12,986,037 €
	Start-Up	600,000 €
[41]	Design	0.24 m€
	PTO	215.38 m€
	Mooring	18.73 €
[40]	500 MW CAPEX	4.6 m€
[56]	Device	$112,312,800
	Mooring	$21,104,460
	Anchors	$44,064,000
	Facilities	$12,000,000
	Electrical System	$4,350,000
	Construction Financing	$9,691,340
	Construction Management	$16,940,702
	Commissioning	$17,647,000 (5% of cost)

literature are listed in Table 2.

For offshore wind in the US, capital costs vary based on depth of installation and discount rate. At 3% discount, capital cost is given as 71.80 to 81.77 $USD/MWh. At 5%, it is between 106.04 and 120.76, and for 7%, it is 135.72 and 154.47 $USD/MWh [55]. Installation costs for a commercial Pelamis P1 wave power plant in California are estimated at $2.79 million, composed of cost components summarized in Table 2 [56]. In a co-located fixed-bottom wind-wave array, the capital costs included "all costs incurred by" the WEC device, PTO, mooring, installation, and electrical system (further described in 2), and was estimated as 513–607 m€ [37].

In this study, we estimated each subsystem's design to be 0.24 m€ converted to $USD, based on [41]. The value for $C_{Build_{WEC}}$ includes the cost components for the device, mooring, and PTO on a per WEC (i_{WEC}) basis [37].

$$C_{Build_{WEC}} = 1,519,037 * i_{WEC} \tag{9}$$

The value for $C_{Build_{Turbine}}$ is based on the rated capacity of the turbines ($P_{Rated_{Turbine}}$) (MW) [39], and is derived from the cost of the turbine and the floating platform material cost.

$$C_{Build_{Turbine}} = P_{Rated_{Turbine}} * 1,480,000 \tag{10}$$

This cost to build the turbine does not include mooring for the turbine. Anchoring and mooring is calculated by summing the cost of the anchoring and mooring components, the length of the anchoring and mooring lines (h) (m), and the number of turbines ($i_{Turbine}$).

$$C_{Mooring_{Turbine}} = (39772 + 520820 + (1096h)) * i_{Turbine} \tag{11}$$

The substation cost equation is dependent on rated power (MW) and assumes the substation is onshore [39].

$$C_{Substation} = 20,000 * P_{Rated} + 2,000,000 \tag{12}$$

Cabling cost is the sum of the inter-array and export cables, and is based on the length of the inter-array ($l_{Inter-array}$) (m) and export cables (l_{Export}) (m) [39].

$$C_{Cable_{Inter-array}} = 307 * l_{Inter-array} \tag{13}$$

$$C_{Cable_{Export}} = 492 * l_{Export} \tag{14}$$

Cost of installation [39] is determined on a per device basis:

$$C_{Installation} = 977620 * (i_{Turbine} + i_{WEC}) \tag{15}$$

3.3. Operation

Operational costs include O&M, but also insurance costs, and costs associated with ongoing business, administration, and legal services and resources.

$$C_{Operation} = C_{O\&M} + tC_{Insurance} + tC_{Administration} \tag{16}$$

Administrative costs are calculated by multiplying the sum of yearly administration, business, and legal fees ($C_{Administration}$) by the lifespan (t) of the co-located array. O&M costs are calculated by multiplying the sum of the yearly cost of maintenance by the lifetime of the farm. A factor of 0.82 was applied to account for the 12% reduction in O&M costs [37].

$$C_{O\&M} = 0.82t\left(C_{O\&M_{Turbine}} + C_{O\&M_{WEC}}\right) \tag{17}$$

The cost of turbine O&M is dependent on the rated power of the turbines (MW) [57], and the cost of WEC O&M is based on the rated power of WECs (MW) [37].

$$C_{O\&M_{Turbine}} = P_{Rated_{Turbine}} * 133,000 * t \tag{18}$$

$$C_{O\&M_{WEC}} = P_{Rated_{WEC}} * 228,564 * t \tag{19}$$

Operations costs from existing literature are included in Table 3.

Although insurance costs vary by development phase, the costs of insurance have been summed over all development stages and included in this operational phase for simplicity. Insurance cost is calculated by an insurance rate ($r_{Insurance}$) applied to the project cost.

$$C_{Insurance} = r_{Insurance}\left(C_{Pre-installation} + C_{Implementation} + C_{Operation} + C_{Decommission}\right) \tag{20}$$

Table 4 cites insurance costs used in previous literature. In this study, we use an insurance rate of 2% of O&M costs [54].

Administration costs are calculated by multiplying the yearly support service, business, and legal fees by the lifespan (t) of the co-located array.

$$C_{Administration} = t\left(C_{SupportServices} + C_{Business} + C_{Legal}\right) \tag{21}$$

Administrative cost values used in existing literature are described in Table 3. In this study, we used $3 million in administrative fees [40].

3.4. Decommissioning

Decommissioning costs include the cost of removal of the devices, mooring, anchors, and the electrical system on the energy

Table 3
O&M costs.

Reference	Description	Cost
[37]	*Wind (Alpha Ventus)*	
	Maintenance	8.8 €/MWh
	Administration and misc.	5.5 €/MWh
	Insurance	3.3 €/MWh
	Rent	3.3 €/MWh
	Electricity	1.1 €/MWh
	Wave only (30 WECs)	
	Maintenance	3,150,900 €/yr
	Other	133,200 €/yr
	Insurance	4,020,843 €/yr
	Rent	243,945 €/yr
	Co-located	−12%*O&M
[38]	Insurance	8,622,250 €
	Business, administration	3,000,000 €
	O&M	302,730,039 €
	Maintenance	64,728,921 €
	Insurance	6,137,841 €
	Insurance, business, Anchors	6,728,996 €
	administration, and O&M costs	10,582,566 €
	for a 5 MW Windfloat site	
[40]	Maintenance	4.766 m€/yr
	Insurance	17,500 €/MW
[41]	Insurance, business,	107.93 m€
	administration, and O&M costs	
	for 5 MW Windfloat site	
[56]	Maintenance	$6,618,177/yr
	10-year Refit	$23,534,601
	Insurance (2% IC)	$4,295,752/yr

Table 4
Insurance rates.

Reference	Description	Cost
[37]	Carbon Trust	2%
[38]	Carbon Trust/EWEA	13–14% OPEX
[40]	EPRI	37 €/MWh
[41]	IWEA	15,000 €/MW
[37]	Astariz (average of those above)	3.3 €/MWh
[56]	EPRI Oregon (about $4,296,000, and is for mature offshore tech)	2% Total O&M Cost

site after the project lifespan of 20 years. Each of these subsystems includes dismantling, transport, and processing between the site and the port. After processing, the site is cleaned, followed by removal from the port of materials to be dumped or sold as scrap.

$$C_{Decommissioning} = C_{Dismantling} + C_{Transport} + C_{Processing} + C_{Cleaning} + C_{Removal} \tag{22}$$

Decommissioning costs in existing literature are in Table 5. For this study, we based decommissioning costs on percentage of total project costs. This cost category was the most variant of the cost categories. Thus, to account for this uncertainty and variation, we use a range of values (from $C_{Decommissioning_{low}}$ to $C_{Decommissioning_{high}}$) of the co-located array [38,40].

$$C_{Decommissioning_{low}} = 0.000017 * C_t \tag{23}$$

$$C_{Decommissioning_{high}} = 0.03 * C_t \tag{24}$$

3.5. Power production

The energy produced by the co-located array is dependent on the devices chosen for the site, their layout (which determines their interactive effects on power production), and site-specific resource availability. The energy production of the co-located array (in MWh/year) is the sum of the wave energy produced by the WECs ($O_{t_{WEC}}$) and the wind energy produced by the floating offshore wind turbines ($O_{t_{Turbine}}$), and is dependent on the efficiency of transmission equipment ($\eta_{transmission}$).

$$O_t = \eta_{transmission}(O_{t_{WEC}} + O_{t_{Turbine}}) \tag{25}$$

3.5.1. Wave power production

The wave energy produced by the WECs is dependent on the number of hours a year (t) the WEC is available ($\eta_{availability_{WEC}}$) to produce power, the efficiency of the device ($\eta_{efficiency_{WEC}}$), the number of WECs in the space (n_{WEC}), and the power produced by each device ($O_{t_{Device,WEC}}$):

$$O_{t_{WEC}} = \eta_{availability_{WEC}} * \eta_{efficiency_{WEC}} * n_{WEC} O_{t_{Device,WEC}} * t \tag{26}$$

The wave energy produced by a single WEC ($O_{t_{Device,WEC}}$) can be calculated either by use of the WECs empirically determined power matrix and the local sea state matrix, or by the calculation of raw wave energy available based on wave period (T_e) and significant wave height (H_{m0}). In this study, we use the latter method, paired with a wave modeling software that provides local environmental context to the input variables wave height and period.

$$O_{t_{Device,WEC}} = \frac{\rho_{water} * g^2}{64\pi} T_e * H_{m0}^2 \tag{27}$$

The density of seawater (ρ_{water}) is in kg/m^3, g represents the gravitational acceleration in m/s^2, T_e is measured in s, and H_{m0} is measured in m. Using SWAN, this study is able to account for local environmental factors when determining wave height, wave period, and power. WECs, as described in the case study, are represented using empirically-determined transmission and reflection coefficients published in previous research [42] to calculate energy produced.

3.5.2. Wind power production

The wind energy of the co-located array is dependent on the availability of the wind turbines ($\eta_{availability_{Turbine}}$), the efficiency of the wind turbines, the energy produced in a year (t), the number of turbines ($n_{Turbine}$), and the energy produced by each turbine ($O_t Device, Turbine$):

$$O_{t_{Turbine}} = \eta_{availability_{Turbine}} * \eta_{efficiency_{WEC}} * n_{Turbine} * O_t Device, Turbine * t \tag{28}$$

The power produced by each turbine is calculated using a model-specific power curve, a generic power production equation, and a model that accounts for wake effects. The power produced by each turbine over a given range of wind speeds is represented by the turbine's power curve. This power curve is empirically derived, thus each model and size of turbine has its own power curve. As an example, the power curve for the turbine we use in this case study is shown in Fig. 1.

Each turbine model has a cut-in wind speed, rated wind speed, and cut-out wind speed. At wind speeds below the cut-in wind speed (in Fig. 1, this is about 4 m/s), the turbine does not produce power. At wind speeds between the cut-in wind speed and rated wind speed (in Fig. 1, this is about 15 m/s), power prediction is calculated using Eq. (29).

$$O_{t_{Turbine}} = \frac{1}{2}\rho_{air} A U^3 C_p \tag{29}$$

where ρ_{air} is the air density in kg/m^3, A is the swept area of the turbine blades (m^2), U is the wind speed in m/s, and C_p is the power coefficient. In this study, we use 0.34 for the power coefficient. Wind energy produced is only calculated for wind speeds above the turbine's rated cut-in wind speed.

We account for wake effects through a three-dimensional extrapolation of the Park Wake Model, where the wind speed downstream of the wind turbine is calculated by Eq. (30) [59].

Table 5
Decommissioning costs.

Reference	Description	Cost
[37]	0.75% IC	4,080,690 €
[38]	Device	59,092,054 €
	Platform	255,000 €
	Mooring, Anchors	496,096 €
	Electrical System	2,747,353 €
	Cleaning	1,730,914 €
	Processing (dump/scrap)	−42,426,742 €
[40]	Dismantling and eliminating of material, cleaning of site	3% of total costs
[41]	Removal, transport, and recycle	0.0017% of IC

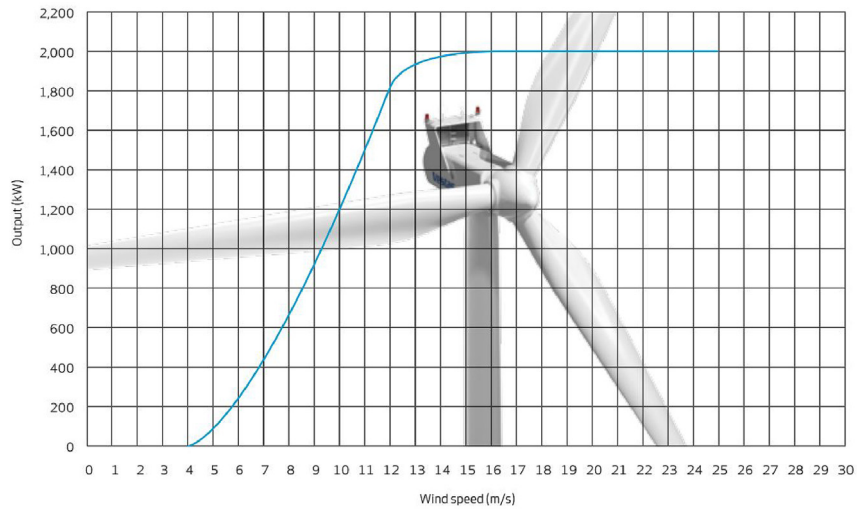

Fig. 1. Power curve for V80-2.0 MW turbine [58].

$$U = U_0\left(1 - \frac{2}{3}\left(r_r/r_r + \alpha_y\right)^2\right. \tag{30}$$

where (U_0) is the ambient wind speed in m/s, (r_r) is the rotor radius of the upstream turbine, and (α_y) describes the air entrainment and is represented by the following equation:

$$\alpha = 0.5 \Big/ \left(ln\frac{z}{z_0}\right) \tag{31}$$

where (z) is the hub height and (z_0) is the surface roughness.

4. Assumptions and uncertainties

Assumptions we made to develop this cost model and the uncertainty that accompanies it can be sectioned into those pertaining to 1) cost categories and 2) cost values. An assumption about a cost category might include, for instance, assuming we should include insurance costs in the model. By the same example, the assumption about the cost value would then be that insurance costs total $100.

4.1. Cost categories

Pertaining to cost categories, we included lifecycle cost categories, which comprehensively cover those costs from project definition to dismantling as outlined by Castro-Santos [38]. However, we understand that cost categories for a given development are project-specific and may vary. For instance, we assume in this paper that there are design costs for the devices. In reality, there may be a design cost, or the design costs may have already been funded through a research or industry grant, so that it is not a part of the developers project budget. Conversely, it is possible that there are additional costs associated with a project that we have not included. We will be able to better account for these cost categories as we gain commercial experience installing devices in various contexts around the world. In this study, we describe each cost category to avoid confusion over what costs we included and why.

4.2. Cost values

We relied on previous literature to provide values for the costs included in the model. Where they existed, we tried to find a range of values per cost category, which are summarized in tables in previous sections. When discerning between multiple values of a cost value, we determined which to use by comparing which was most applicable to the scale of the proposed array, the proposed location, and the purpose of this cost model. For instance, if there was a discrepancy in transmission cable costs, we chose the cost that most closely aligned with our application (a commercial-scale array with over 100 devices). Because we relied on previous literature to obtain cost values, there is uncertainty in our cost model relating to how those values were originally derived, and their relevancy for our model. Where possible, we investigated how each value was derived, and judged whether it would be appropriate to use for our model. Values with an explanation for how they were derived were used over values with no explanation.

5. Case study

In this case study we exemplify the use of our cost model by calculating the levelized cost of energy for a co-located floating wind-wave array.

5.1. Study area

In this case study, we use an area in the North Sea (Fig. 2), due to the availability of long-term descriptions of the metocean environment [60]. Site 15 of the European Union's MARINA Project (or Marine Renewable Integrated Application Platform) [61] is located in Denmark, North Sea Center (3.43° E, 55.13° N). The general characteristics of Site 15 are summarized in Table 6.

The MARINA Platform Project provides marginal and joint distributions of wind and wave data for the study location. The National and Kapodistrian University of Athens provided the 10 years (2001–2010) hourly raw data for the 5 selected offshore sites. Both marginal and joint distributions are obtained by fitting analytic solutions to raw data and are characterized by 1-h mean wind speed at 10 m above mean sea level (U_w), significant wave height (H_s) and spectral peak period (T_p) [60].

The joint probability density function (PDF) of U_w, H_s, and T_p is defined by the marginal PDF of U_w $(f_U w)$, a PDF of H_s conditional on U_w $(f_H s|U_w)$ and a PDF of T_p conditional on $H_s(f_T p|H_s)$. The parameters and equations that define these distributions can be found in the original description of site conditions [60]. The derived representative sea states are described in Table 7. Typical bin sizes for H_s

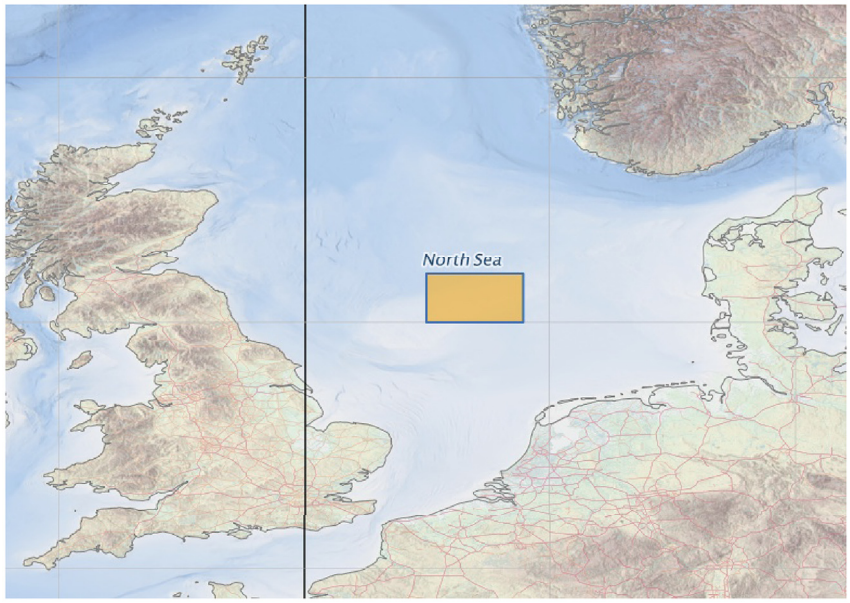

Fig. 2. Site location [62].

Table 6
Site characteristics.

Parameter	Value
Water Depth [m]	29
Distance to shore [km]	300
50-year U_w at 10 m [m/s]	27.2
50-year H_s	8.66
Mean value of T_p	6.93

Table 7
Representative long-term environmental conditions.

Sea State	U_w [m/s]	H_s [m]	T_p [s]	Prob. [%]	Occ./year [hrs]
1	2.2	0.49	5.93	4.8	420.48
2	5.0	0.64	6.06	12.3	1077.48
3	8.0	0.73	6.13	7.5	657.00
4	11.1	0.77	6.17	2.0	175.20
5	14.3	0.80	6.19	0.3	26.28
6	2.2	1.15	6.47	0.3	26.28
7	5.0	1.26	6.55	5.5	481.80
8	8.0	1.43	6.68	16.3	1427.88
9	11.1	1.56	6.78	12.4	1086.24
10	14.3	1.63	6.83	3.7	324.12
11	17.4	1.66	6.86	0.6	52.56
12	20.5	1.69	6.88	0.1	8.76
13	8.0	2.22	7.28	1.8	157.68
14	11.1	2.37	7.40	8.9	779.64
15	14.3	2.51	7.50	8.0	700.80
16	17.4	2.58	7.56	2.4	210.24
17	20.5	2.61	7.58	0.3	26.28
18	11.1	3.21	8.05	0.6	52.56
19	14.3	3.35	8.16	3.7	324.12
20	17.4	3.48	8.26	3.3	289.08
21	20.5	3.55	8.32	0.9	78.84
22	23.6	3.59	8.35	0.1	8.76
23	14.3	4.21	8.85	0.2	17.52
24	17.4	4.35	8.96	1.3	113.88
25	20.5	4.47	9.06	1.0	87.60
26	23.6	4.54	9.11	0.2	17.52
27	17.4	5.22	9.68	0.1	8.76
28	20.5	5.36	9.80	0.4	35.04
29	23.6	5.47	9.89	0.2	17.52

and T_p are 0.50 m and 2.0 s, respectively. Initial derivation of representative sea states using smaller bin sizes resulted to 120 environmental conditions, from which a number of conditions have a very low probabilities ($P < 0.001$). Assuming insignificant contributions from low-probability sea states ($P < 0.001$), and considering only sea states within the operational conditions ($Uw > 4$ m/s) the representative number of sea states was reduced to 29 conditions, which covers 99.2% of the total sea states occurrence. More details about the derivation of the sea states can be found in Ref. [33].

5.2. Wave modeling

To model wave propagation, we used Simulating Waves Nearshore (SWAN), a wave simulation tool, [63–65]. Using a nested grid approach, we defined the outer, coarse grid area from 2.45° to 3.45° E and 54.50° to 55.75° N, with a mesh size or grid resolution of 200 m by 200 m. We defined the nested grid area from 3.10° to

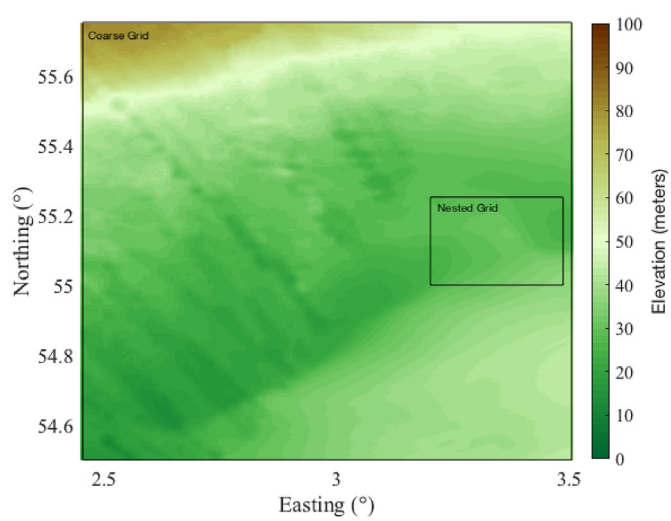

Fig. 3. Location of study area and definition of grid areas (nested grid is shown outlined in black).

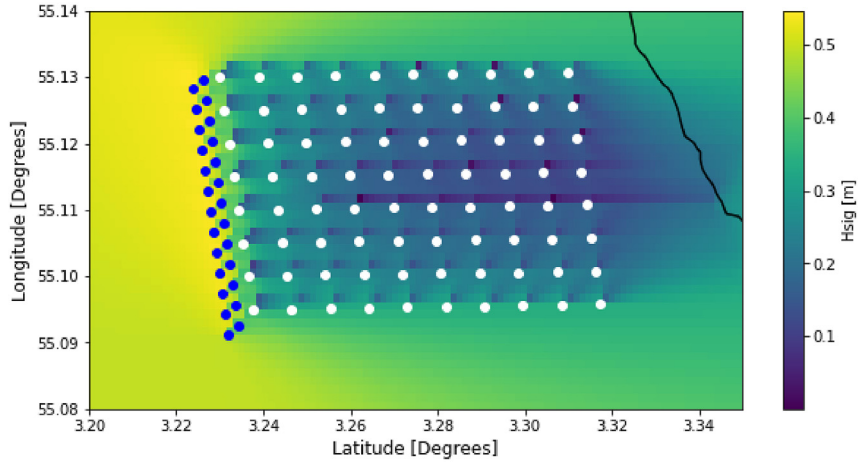

Fig. 4. Co-located array of 26 WECs staggered in two rows, and 80 turbines in an oblique rectangle layout.

3.45° E and 55.00° to 55.25° N with a mesh size of 80 m by 80 m. These grid areas can be seen in Fig. 3. Bathymetric data used in this study is from EMODnet's Bathymetric Tool [62]. A JONSWAP spectrum model was used because it is based off of observations of wave fields in the North Sea [66]. We represented WECs in SWAN to calculate power production by a transmission coefficient of 0.80 and a reflection coefficient of 0.45 [42].

The floating offshore wind turbines were represented similarly to how fixed-bottom wind turbine foundations are represented in existing literature [21], with a transmission coefficient of 0.0 (all incident wave energy absorbed). We also assume a 0.0 coefficient for reflection, so that the wave energy calculation is not affected by reflection from the floating offshore wind turbines. In reality, the transmission and reflection coefficients will depend on the type of platform and mooring chosen for the floating offshore wind turbine. Assuming total absorption and no reflection does not change the wave or wind energy converted by the devices, nor does it change the cost calculation in this study. However, it is worth noting that currently, there is little research documenting how to represent floating offshore wind turbines via these coefficients.

5.3. Array layout

The wind farm consists of 80 turbines laid out in an oblique rectangle that is 5 km by 3.8 km at depths of 6–14 m. Wind turbines were placed at a minimum distance of 560 m from each other. The WECs were placed at minimum distance of 280 m from the wind turbines, and 198 m (or 2.2D) from each other. We used the WindFloat 2.0 MW prototype platform, which uses Vestas V80-2.0 MW turbines. Although the Central North Sea location is in shallow waters where floating wind turbines are not necessary, this study provides a comparison in cost for these two technologies based on a well-studied environment.

The WEC array modeled in this study was comprised of 26 overtopping WaveCat [42] devices, which are each 90 m in diameter. These WECs were staggered in two rows west of the wind turbine array, facing the dominant wave direction. Fig. 4 depicts this layout.

Based on the power production of the co-located array and the cost methodology described, LCOE was calculated given parameters listed below in Table 8.

Fig. 5 shows a schematic of how cabling was assumed to be arranged in the co-located array for calculating cable lengths.

Table 8
LCOE input parameters.

Reference	Category	Value
	Lifespan	20 years
	Number of WECs	26
	Number of floating turbines	80
[42]	Rated Power of WEC	1.2 MW
[40]	Rated Power of Turbine	2.0 MW
	Borrowing Rate	293.70 €/MWh
	Inflation Rate	293.70 €/MWh
	Exchange Rate (€ to $USD)	1.09
	Mean water depth	29 m
	Length of inter-array cable	22400 m
[56]	Length of export cable	15000 m
	Cost per length inter-array cable	307/m
	Cost per length export cable	492/m

6. Results & discussion

6.1. Power production

Wind power production was calculated for 80 Vestas V-80 2.0 MW turbines using Eq. (29) given the constraints provided by the power curve in Fig. 1 and the wake effects in Eq. (30), as well as inputs site resource characteristics (Table 6). The wind turbines have a rotor diameter of 80 m, and a hub height of 70 m. The capacity factor is 0.4 [67]. The resulting wind power summed over 80 turbines, accounting for the probability of occurrence and annual hours of occurrence, is 652,453 MWh/year. The efficiency calculated for the wind site was approximately 90%, and represents the ratio of the actual power produced by the wind array over the total power potential given the wind conditions.

Wave power production was calculated using the characteristic sea states from Table 6 and SWAN. We then multiplied the converted power output from SWAN by the probability of occurrence, efficiency, and availability. We assumed 90% efficiency, and 95% availability. Availability represents the time a device produces power over a given period of time. The efficiency value for the WEC is adapted from previous literature [37] to be consistent with the wind array efficiency, and the availability value comes directly from previous literature [37]. Based on this data and SWAN simulations, the resulting wave power produced over 26 WaveCat devices in the described configuration was 465,278 MWh/year.

6.2. Levelized cost of energy

Based on the described methods for power and cost calculation,

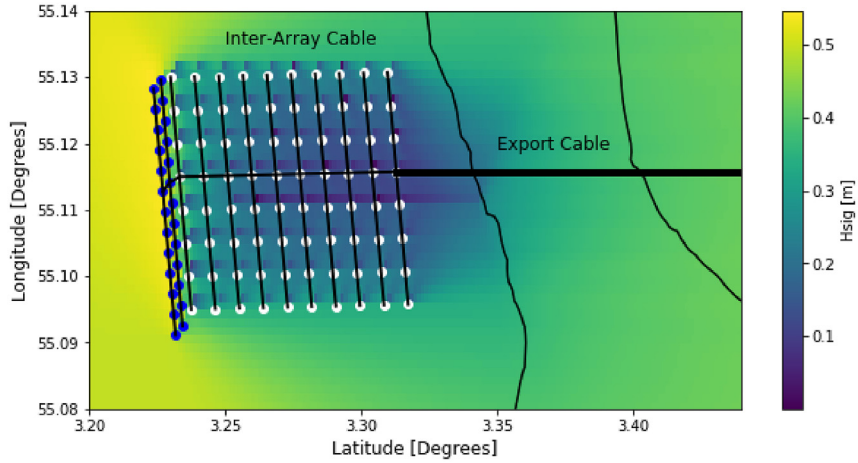

Fig. 5. Cable layout for co-located array: inter-array cabling is in thin line, with export cable in thick line (export cable continues to shore).

the LCOE for the co-located floating wind-wave array was calculated to be $75.02-$78.38/MWh, or 87.26–91.89 €/MWh. A cost breakdown for the different phases of cost model development is shown in Fig. 6.

Pre-installation and decommissioning phase costs account for 10% or less of project costs, with decommissioning costs being negligible in the low-estimate case, which assumes some materials of the devices can be sold for scrap. This assumption about the end-life phase of the devices is uncertain, and changes in the end-life of the devices could lead to significantly different costs. Even with this uncertainty and variability in decommissioning costs, the ratio of the decommissioning costs to the costs of implementation and operation costs is expected to remain low.

Implementation and operation cost categories are nearly equivalent and are the majority of the costs. This result stresses the importance of improving cost synergies in both phases; if costs can be shared in either the implementation or the O&M of the array, it could lead to a significant reduction in cost of the system. Further, this result also stresses the importance of accurately estimating implementation and O&M costs. Our methods for estimating O&M, as in many previous studies, use fixed values for availability, efficiency, and O&M annual costs. In reality, all three of these variables change in value from year to year, and also across the lifespan of the array. The effect of these fixed values on the results is that the OPEX costs and power production each year does not vary as it would in a real installation. The effect of failures and downtime on O&M costs and power production, for instance, can not be taken into account in our cost model, unless the fixed O&M values are replaced by an output from an O&M simulation-based method. Integration of simulation-based O&M estimates would allow for the inclusion of context-dependent variables, such as frequency and severity of a particular device's failures. Further, the differences in O&M between WECs and floating offshore wind turbines could be accounted for in a more comprehensive way. Because of different technology maturity levels, common failure modes, accessibility, and required O&M strategies, the frequency, duration, and cost of optimal O&M strategies may differ for WECs versus floating offshore wind turbines. These optimal strategies need to be compared and optimally combined to maximize power production and minimize cost. Simulation-based O&M methods would allow for inclusion of varying O&M requirements and strategies.

When considering how the presented cost model compares various array developments, Fig. 7 shows that co-located floating wind-wave arrays are the least expensive, compared to floating wind-only arrays, and wave-only arrays. This is thought to be mainly due to the increase in power production from co-location and the consideration of shared costs in the cost model. Therefore, the cost model is sensitive to variables that affect power production, such as the efficiency of the device, the transmission and absorption coefficients used to represent the WECs in SWAN, and the wind and wave resources at the array location. LCOE values shown in Fig. 7 also depend on layout of the array, the number of devices in the array, and the variability of the energy resource. In this study, the number of devices and their layout were not optimized, but in a commercial installation, they would be optimized under development constraints. The inter-annual variability of the energy source was represented by a joint distribution that was developed using 10 years of wave and wind data at the specified location. Although this is a great representation of environmental resource patterns at the site, there may be extreme events not accounted for by the joint distributions. Additionally, this study does not account for low-probability events ($P < 0.001$), but we

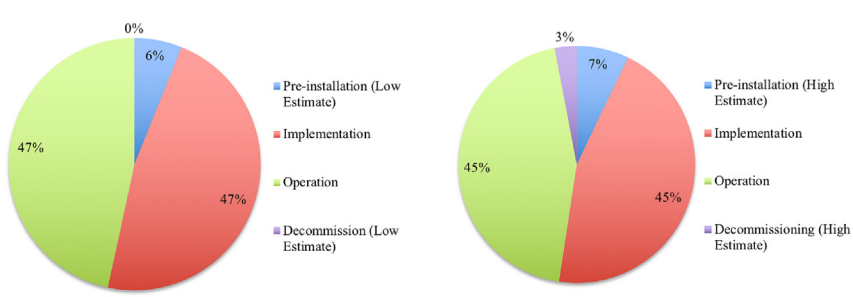

Fig. 6. Cost breakdown of a floating wind-wave co-located array.

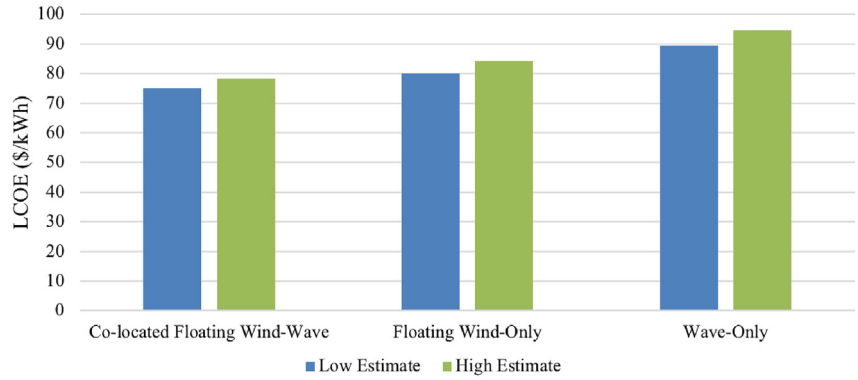

Fig. 7. The presented cost model's comparison of array types.

recognize that extreme events could affect O&M costs, as well as power production.

Compared to floating offshore wind alone [40], the floating wind-wave co-located array case is found to be comparably or less expensive. While the cost of WEC arrays are more expensive [37], the relative cost benefit from increased power production and the decrease of LCOE due to shared costs between the arrays decrease cost in a co-located array scenario. These findings indicate that co-location is advantageous for both the wave energy and floating offshore wind energy industry, but the wave energy industry experiences greater cost reductions in the co-located scenario.

When we compare the LCOE values from our cost model to those from previous literature, we see that our cost model produces lower LCOE values with less variability than results from recent lifecycle cost approaches for offshore wind and wave energy [38,40,51], and cost analyses for co-located arrays [37] (Fig. 8). It is important to consider that devices, location, and costs are not consistent across these studies, nor are the methods for calculating power production, cost of the arrays, or the type of cash analysis (whether the cash analysis is in real or nominal terms). Due to these differences in methods and contexts, the studies should not be directly compared. However, understanding how the presented cost model compares to previous literature can bring attention to the sensitivities of the model. For instance, our resulting LCOE is low. This could be due to low cost estimates (like those associated with uncertain costs like OPEX) or underestimates (like the mooring cable length, which is dependent on a 29 m depth, rather than deeper water in which floating offshore wind turbines would realistically be installed). This low LCOE could also be due to high levels of power production. In this study, we assume unidirectional wind and wave conditions, so that the WECs and floating offshore wind turbines are always facing the oncoming wind direction. In reality, multi-directional wind and wave conditions will reduce the time that the devices will be facing the incoming wind and wave direction, and therefore decrease the power produced by those devices. Further, we use average transmission and reflection coefficients based on experiments of a scaled WEC. While these coefficients represent the most accurate information available and are device-specific, a more accurate study would vary these coefficients with wave parameters. An opportunity for future work would be to empirically define transmission coefficients over a larger range of wave conditions for a specific WEC design, and integrate these wave-specific coefficients for each characteristic sea state.

6.3. Limitations & future work

While these results provide increased understanding about how the cost of a co-located floating wind-wave array is composed of different lifecycle costs and how it compares to other types of offshore renewable energy developments, there is variability and uncertainty inherent in these calculations.

First, these results are dependent on the specific devices chosen for this study, as well as the parameters used to model them. Costs of floating offshore wind turbines and (especially) WECs currently vary widely. The future costs of these devices as they move from custom-build, small-scale production to commercial-scale production is uncertain. The various costs associated with these devices are expected to decrease over time, as has been seen in the fixed-bottom offshore wind energy industry. Likewise, floating offshore wind turbines are expected to benefit from industry

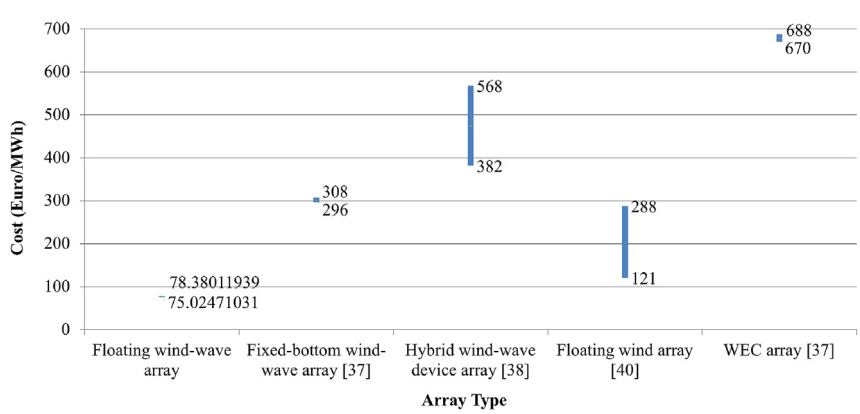

Fig. 8. Comparison of LCOE values from previous literature.

experience.

In addition to changes in cost, power production from these devices will change depending on the models chosen for the cost analysis and as the industry gains experience over time. For instance, the wind turbine used in this study is common amongst installed fixed-bottom offshore wind turbines, but will quickly be surpassed by larger wind turbines (DTU currently has a 10 MW reference model turbine, and the largest turbine in production currently is the General Electric Haliade-X 12 MW turbine). If we increased the size of the 2 MW turbines used in this study, the LCOE would decrease due to increased power production. However, the cost of leased space would either need to increase to accommodate these larger turbines, or fewer turbines would need to be installed. Either option to accommodate the size of the turbines would result in a cost change. These larger turbines might also require larger installation and operation equipment, which could contribute to higher costs. Thus, each cost analysis must be considered unique to the devices used.

How the device design is translated into a model also will change the resulting LCOE. For instance, the coefficients used to model the WEC used in this study are based on experimental results of a scaled system. These coefficients have been used in previous literature to model a full-scale system in varying wave conditions, but in reality, will slightly vary depending on both the WEC component sizes and the wave conditions. Changes in these coefficients will lead to changes in the instantaneous power production, and thus, LCOE. Based on how the chosen devices and the method of modeling them would affect the resulting LCOE, each cost analysis must be considered unique to the devices used and how they are being modeled.

Additionally, the power production is calculated via a site-specific joint distribution based on 10 years of hindcast data, but variability or uncertainty associated with these environmental conditions, or simplifications made in modeling these conditions, affect the resulting LCOE. Most interannual or seasonal variability should be accounted for by this data, given that the joint distributions capture the sea state probabilities across 10 years of hindcast data. As stated previously, however, low probability events are not represented in this study.

This study represents critical early research in identifying cost savings associated with co-located arrays, but future research should include specific improvements. For instance, this study does not consider the impact of co-location on technology-specific grants, tariff regimes, or reliability of these systems. Further research needs to be completed to completely understand the ramifications co-location could have for offshore wind energy developments.

7. Conclusions

This paper presents an analytical cost model for a floating offshore wind-wave co-located array. Cost methods are developed using a lifecycle cost analysis approach, while energy is calculated using an extended Park Wake Model for wind, and SWAN wave modeling for wave energy. The LCOE of a floating wind-wave array is \$75.02-\$78.38/MWh, or 87.26–91.89 €/MWh. This cost is less than floating offshore wind turbine arrays and less than WEC arrays, implying there is an economical argument for co-location. This first attempt at quantifying the LCOE of floating wind-wave co-located arrays presents a methodology that can be used in computational optimization techniques to further decrease costs in co-located systems through interactions between devices, as well as site layout.

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