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. When we applied this cost model in a case study, results suggested floating wind-wave co-located arrays are advantageous to WEC-only arrays and cost-competitive with floating wind arrays. 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.

Keywords: co-location, wave energy, cost model, floating offshore wind energy, offshore renewable energy

1. Introduction

In the offshore renewable energy industry, offshore wind is the only technology that has reached global commercial installation. In 2016, global offshore wind capacity reached 14.4 GW, with another projected 3 GW global installed capacity in 2017 [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

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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, 5, 6, 7] and floating [8] offshore 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 development types.

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, 13, 14, 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, 21, 22, 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, 26, 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, 29, 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, 30, 31, 32, 33, 34, 35, 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, 40, 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 choice in 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 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, this study does 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, 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).

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

(PV) is present value, obtained by a discounting method with a given discount rate ($r_{discount}$). The discount rate converts one-time costs to annual costs, and factors out inflation 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 [?], 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.

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

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 [46, 47, 48, 49, 50], 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, 49] 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 [51]. 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

Table 1: Pre-Installation Costs

Ref.	Description	Cost
[37]	"Engineering tasks and licenses" in a co-located wind-wave array	570,000 €
[38][1]	Feasibility study Legislative factors Design for a hybrid wind-wave platform	100,000 € 474,951 € 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 500MW floating wind turbine	104,106 k€ +/- 10%
[52]	Viewshed costs	3%
[53]	Siting and Permits GHG Investigation	2% of IC 0.5% of IC

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.

3.2. Implemention

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.

$$C_{Implementation} = C_{Design} + C_{Build} + C_{Transport} + C_{Storage} + C_{Install} + C_{Commissioning} \tag{5}$$

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.

$$C_{Design} = C_{Design_{WEC}} + C_{Design_{Turbine}} \tag{6}$$

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

$$C_{Build} = C_{Build_{WEC}} + C_{Build_{Turbine}} \tag{7}$$

$$C_{Transport} = C_{Transport_{WEC}} + C_{Transport_{Turbine}} \tag{8}$$

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

The costs per subsystem and cost component that are used in 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 [54]. 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 [55]. 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:

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

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€
[55]	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)

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].

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

The cost of turbine O&M is dependent on the rated power of the turbines (MW) [56], 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.

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

Table 4 cites insurance costs used in previous literature. In this study, we use an insurance rate of 2% of O&M costs [53].

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

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

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 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 [40, 38].

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

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

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 5MW Windfloat site	
[40]	Maintenance	4.766 m€/yr
	Insurance	17,500 €/MW
[41]	Insurance, business, administration, and O&M costs for 5MW Windfloat site	107.93 m€
[55]	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
[55]	EPRI Oregon (about $4,296,000, and is for mature offshore tech)	2% Total O&M Cost

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

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, but the formula to calculate energy production is the constant. First, the power 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 wind turbines ($O_{t_{Turbine}}$), and is dependent on the efficiency of transmission equipment ($\eta_{transmission}$).

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

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 number of WECs in the space (n_{WEC}), and the power produced by each device ($O_{t_{Device,WEC}}$):

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

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 in wave modeling software that provides local environmental context.

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

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 calculating wave height and power. WECs, as described in the case study, are represented using an empirically-determined transmission coefficient published in previous research [42] to calculate energy produced from raw energy. The wind energy of the co-located array is dependent on the availability of the wind turbines ($\eta_{availability_{Turbine}}$), the energy produced in a year (t), the number of turbines ($n_{Turbine}$), and the energy produced by each turbine ($O_{tDevice,Turbine}$):

$$O_{t_{Turbine}} = \eta_{availability_{Turbine}} * n_{Turbine} * O_{tDevice,Turbine} * t \tag{28}$$

The energy produced by a single wind turbine is given by:

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

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 effect [57] through a three-dimensional extrapolation of the Park Wake Model, where the wind speed downstream of the wind turbine is calculated by:

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

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:

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

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 test the proposed cost of energy model for a co-located wind-wave farm that compares fixed and floating offshore wind technologies.

5.1. Study Area

This case study uses the area around the Horns Rev 1 offshore wind farm, which is located 15km west of Blvands Huk (the westernmost point of Denmark) (Figure 1).

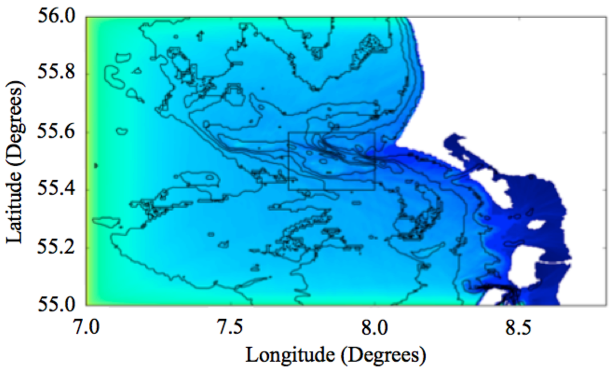

Figure 1: Location of study area and definition of grids (nested grid is shown outlined in black)

5.2. Wave Modeling

To model wave propagation, we used Simulating Waves Nearshore (SWAN), a wave simulation tool, [58, 59, 60]. Using a nested grid approach, we defined the outer, coarse grid from 7.0 to 8.8 degrees latitude, and 55.0 to 56.0 degree longitude with a grid resolution of 200 m by 200 m. We defined the nested, fine grid from 7.7 to 8.0 degrees latitude, and 55.4 to 55.6 degrees longitude, with a grid resolution of 17 m by 17 m (which was based on the smallest device diameter of 18 m). These grids can be seen in Figure 1. Bathymetric data used in this study is from EMODnets Bathymetric Tool. A JONSWAP spectrum model was used because it is based off of observations of wave fields in the North Sea [61].

Fixed-bottom wind turbine foundations were represented by a transmission coefficient of 0.0 (all energy absorbed), while WECs were represented by a coefficient of 0.42 [42]. Due to lack of existing literature, floating offshore wind turbines were represented similar to WECs.

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. This layout was maintained for both fixed-bottom offshore turbines (as exists at Horns Rev 1 currently) and floating offshore wind turbines. We use WindFloats 2.0MW prototype platform, which uses the same Vestas V80-2.0MW turbine as those turbines currently installed at Horns Rev 1. Although Horns Rev 1 is located 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 development. The WEC array modeled in this study was comprised of 26 overtopping WaveCat [42] devices, which are each 90m in diameter. These WECs were staggered in two rows west of the wind turbine array, facing the dominant wave direction. Figure 2 depicts this layout.

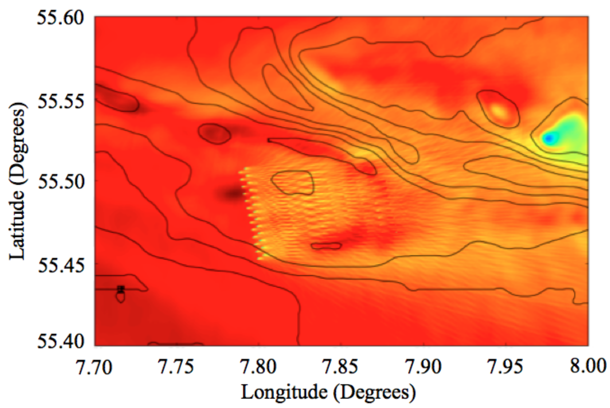

Figure 2: Co-located array of 26 WECs staggered in two rows, and 80 turbines in an oblique rectangle layout

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.

5.4. Power Production

Wind power production was calculated for 80 Vestas V-80 2.0MW turbines using a power curve [62] and Horns Rev 1 wind power characteristics (Figure 3) [63]. The wind turbines have a rotor diameter of 80 m, and a hub height of 70 m. The capacity factor is 0.4 [64]. The resulting instantaneous wind power summed over 80 turbines is 45.42 MW.

Wave power production was calculated with wave height, period, and direction data from [65] (Figure 4).

The mean significant wave height was 1.5 m, and the period was 4.5 s. The availability ($\eta_{availability_{WEC}}$) was assumed to be 0.95 (operating 95% of the year). Based on these assumptions, the resulting instantaneous wave power produced over 26 WaveCat devices in the described configuration was 26.406 MW.

5.5. Levelized Cost of Energy

Based on the power production of the co-located array and the cost methodology described, LCOE was calculated given parameters listed below in Table 6.

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

6. Results

LCOE was calculated to be \$133.15-\$139.11/MWh, or 122.16-127.62 €/MWh, for the described layout of a co-located floating wind-wave array. A cost breakdown for the different phases of cost

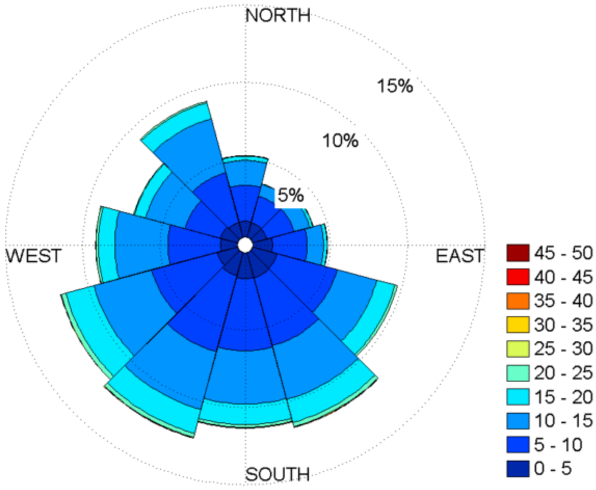

Figure 3: Wind rose for Horns Rev 1, from 1 June 1999 31 May 2002 [63]

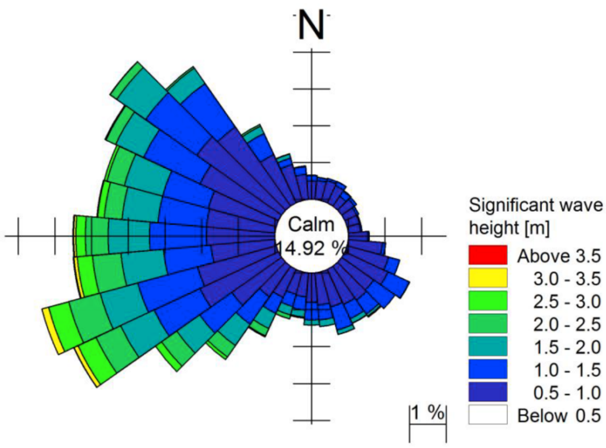

Figure 4: Wave rose of wave height, period, and direction [65]

model development is shown in Figure 6. Implementation and operation cost categories are nearly equivalent, stressing the importance of improving cost synergies in both phases. 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 LCOE value is less than those published in recent offshore wind and wave energy cost literature that also use lifecycle cost approaches [38], [40], [50], and those that analyze cost of co-located arrays [37] (Table 7). This is thought to be due the appropriate consideration of shared costs in the cost model. LCOE values shown in Table 7 all depend on layout of the array, the number of devices in the array, and the energy resource.

Table 6: 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	10 m
	Length of inter-array cable	22400 m
[55]	Length of export cable Cost per length inter-array cable	15000 m 307/m
	Cost per length export cable	492/m

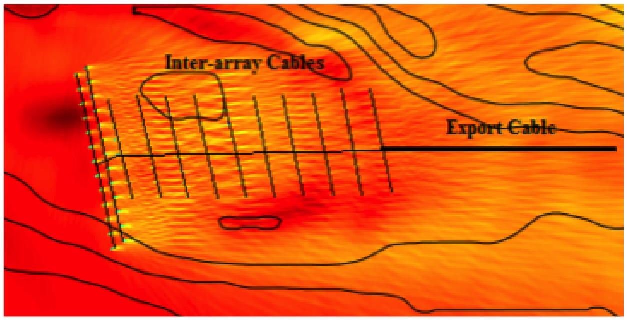

Figure 5: Cable layout for co-located array: inter-array cabling is in thin line, with export cable in thick line (export cable continues to shore)

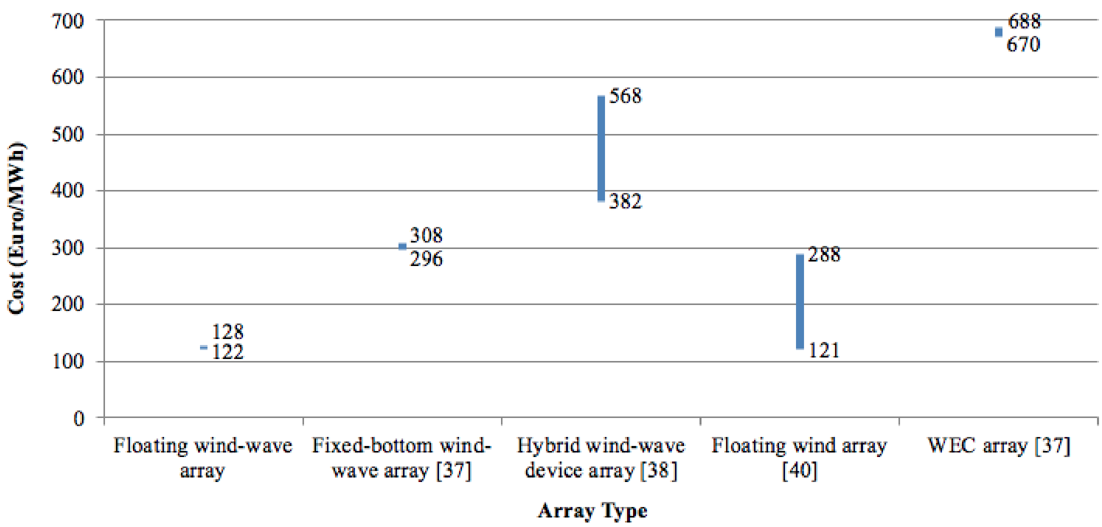

Figure 7: Cost breakdown of a floating wind-wave co-located array

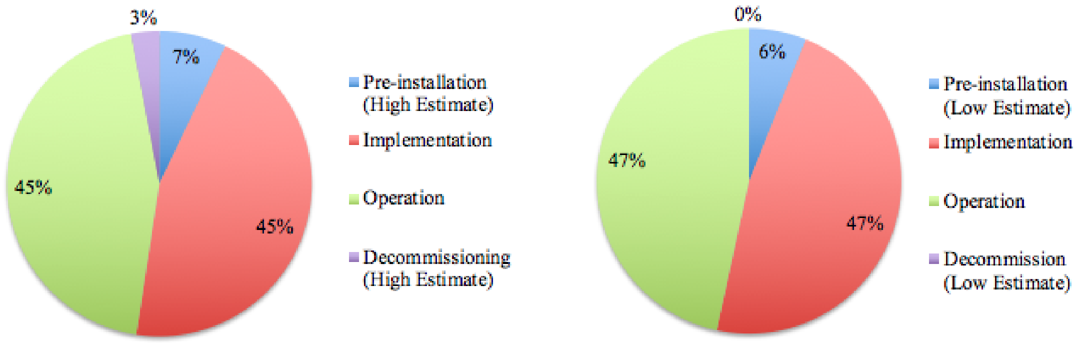

Figure 6: Cost breakdown of a floating wind-wave co-located array

Comparing our LCOE value to the LCOE reported for a (fixed-bottom) wind-wave array, a floating wind-wave co-located array is less expensive. This is reflective of how we accounted for shared costs in the cost model, rather than relative costs of floating wind turbine to fixed-bottom wind turbine structures. 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.

This study only begins to identify cost-savings associated with co-located arrays. 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 \$133-\$139/MWh, or 122-128 €/MWh. This cost is comparable or less than floating offshore wind turbine arrays, and significantly 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.

8. Acknowledgements

Thanks go to the Avangrid Foundation, a subsidiary of Iberdrola S.A, who funded this work.

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