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Impacts of turbine and plant upsizing on the levelized cost of energy for offshore wind

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ABSTRACT

Turbine and plant upsizing are major trends in offshore wind deployment, although the quantitative impact on project costs has not been well-characterized. The uncertain value of continued wind turbine and project growth limits the ability of the supply chain to prepare for future technology trends, leading to challenges in the realization of larger projects. This analysis explores the levelized cost of energy impacts of turbine ratings between 6 and 20 MW and plant capacities between 250 and 2,500 MW for fixed-bottom offshore wind using techno-economic cost models for foundation, electrical, installation, and operation and maintenance costs, along with annual energy production. We consider a nominal set of technology assumptions for all scenarios to isolate economies of size and scale without additional benefits from decreasing turbine capital costs, quantity discounts for larger projects, or optimized technology solutions. These results indicate that using a 20-MW wind turbine in a 2,500-MW power plant array can reduce the levelized cost of energy by over 23% relative to the global average turbine and plant size installed in 2019; primarily because of reductions in the balance-of-system and operation and maintenance costs. We also identify improved installation vessels, optimized export systems, and novel operation and maintenance strategies as additional cost reduction opportunities. These results suggest that upsizing represents a significant cost reduction opportunity for offshore wind energy and will continue to be a main factor in shaping the future of the sector.

1. Introduction

Wind turbine and power plant upsizing have been major trends in global offshore wind deployment. Between 2010 and 2019, the average turbine size installed at global offshore wind power plants increased from below 3 MW to more than 6 MW (Fig. 1). Over the same period, project size of newly installed offshore wind plants doubled from an average of 190 MW to nearly 400 MW globally. Both upsizing trends are widely expected to continue in future years. Today, the largest wind turbines available for commercial purchase in the offshore wind sector are rated at 10.0 MW [1]. A 12-MW wind turbine is currently in prototype testing [2], a 14-MW wind turbine has recently been announced for commercial use by 2024 [3], and a 15-MW wind turbine is expected to begin serial production in 2024 [4]. At the same time, offshore wind project size has also expanded; for example, developers have announced plans to install single wind power plants of up to 3600 MW by the mid-2020s [5],[1] which dwarfs the 2019 installed global average of 400 MW.

Commensurate with this increase in wind turbine and plant size, the levelized cost of energy (LCOE) has declined by more than 40% between 2014 and 2019, as shown in Fig. 1. The relationship between LCOE and upsizing of the turbine and plant capacity is widely acknowledged in the broader literature [10–12] and is characterized as the key driver of future LCOE reductions for offshore wind [13]. This trend is borne out by the common practice of project developers selecting the largest wind turbine rating that is commercially available at the time of financial close, which can be inferred to maximize their economic advantage. However, despite the clear indications of the offshore wind industry's preference to select higher turbine and project capacities, a quantitative assessment of their impact on LCOE is largely absent from the literature. In this study, we model the cost and performance benefits of turbine and plant upsizing for offshore wind and suggest that these trends will continue in the near future. This matters for supply chain contributors, such as component manufacturers, vessel operators and designers, and port infrastructure planners, who need to anticipate upcoming technology directions to develop sufficient infrastructure capabilities to support large-scale offshore wind energy deployment.

Conceptually, the advantages of wind turbine and plant upsizing are straightforward. Economies of size are realized when a wind power

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[1] Often installed in several phases.

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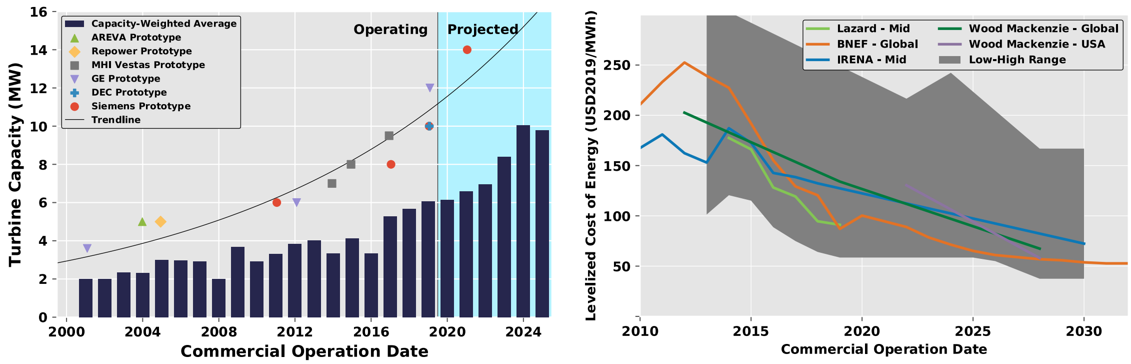

Fig. 1. Global trends in commercial and prototype turbine rating (left) and the levelized cost of energy (right). Wind turbine data collected from [1,2], and [3]; LCOE projections sourced from [6–8], and [9].
Source: Figures reprinted from [10].

plant of a given capacity requires fewer turbines because the rating of each turbine is higher. Fewer turbines implies a smaller number of substructures, reduced total array cable lengths, and shorter total installation times. Larger plant capacities realize economies of scale by distributing “fixed” costs, such as the export system, vessel mobilization, or operation and maintenance (O&M) expenditures over a larger number of generation assets. However, the existing literature on cost impacts from offshore wind turbine and plant upsizing is sparse and contradictory. Wiser et al. [13] surveyed over 160 of the world’s foremost wind energy experts and concluded that increased wind turbine rating had the highest cost reduction impact (economies of scale from increased project size ranked fourth). Conversely, Chen et al. [14] considered the influence of turbine rating on the LCOE of land-based projects and found that costs rise if turbine ratings increase past an optimal value, although costs were also driven by the assumed wind resource. They employed wind statistical data in combination with a turbine cost model. Using empirical models of the increase in weight, cost, and loads as a function of scale, Sieros et al. [15] also found a minimum cost of energy at a particular rotor diameter and concluded that technological innovations were required to counteract the mass scaling laws that drive wind turbine design. Others identify the point at which further increases in turbine rating is no longer economical, such as Ederer [16]. Ederer [16] adopts the decision rationales of a project developer focused on profitability and find that wind turbine ratings above 10 MW would not be viable because of the diminishing energy yield of larger turbines. Using parameterized equations from simulations in a cost model, Ioannou et al. [17] conclude that an increase in turbine size results in an inverse exponential reduction in capital costs, O&M costs, and LCOE. Kikuchi and Ishihara [18] explore the upscaling effects for a semisubmersible floating platform using 5- and 10-MW wind turbines. Using an engineering cost model, they found an LCOE reduction between 45% and 57% compared to a 2-MW turbine. The experts surveyed in [13] anticipated an average turbine rating of 11 MW by 2030, prior to the announcement of the 12-MW General Electric Haliade-X [2], the 14-MW Siemens Gamesa [3], or 15-MW Vestas turbines [4] expected for commercial deployment in 2022 and 2024. This deployment schedule (if achieved) outpaces a number of recent expert predictions and indicates the strong incentive wind turbine manufacturers and developers seems to have for higher turbine ratings.

Cost savings are expected to not only be derived from the capital costs of the project, but also from operational costs and economies of scale. Hofmann and Sperstad [19] compared the O&M costs of a representative project comprising 5- or 10-MW turbines using an O&M simulation tool. They found that reducing the number of wind turbines could reduce operational costs by nearly 25% if the failure rates of the larger turbines were assumed to be the same as their smaller predecessors. Economies of scale for larger projects seem to present particularly contradictory results in existing literature. Dismukes and Upton Jr. [20] found no significant cost savings arising from plant capacity in a statistical analysis of empirical project data. van der Zwaan et al. [21] identified relatively small cost decreases of 3% as capacity increases from a learning curve approach, Junginger et al. [22] suggested that quantity discounts are available for larger projects, and Maness et al. [23] reported cost reductions of up to 50% in the balance-of-system (BOS) costs as plant capacity grows from 50 to 250 MW, using a bottom-up engineering model.

A critical limitation in the existing literature is a lack of system-level modeling approaches that consider the multitude of impacts on the different cost components of an offshore wind project. Varying the size and number of turbines affects the capital costs of turbines, substructures, electrical infrastructure, and installation costs; O&M costs; and energy production, which all must be considered quantitatively when evaluating the net impact on LCOE. The existing literature reviewed earlier focuses either on bottom-up modeling of a specific component or cost category, top-down modeling of overall project costs, or statistical analysis of empirical project data. These studies do not consider how changes in the design of one parameter propagate to other parts of the system and therefore do not yield sufficient resolution to understand how individual cost categories scale with wind turbine rating or plant capacity. As a result, the academic literature cannot satisfactorily explain the clear industry trends toward larger turbine and plant capacities, and does not provide sufficient insight into how offshore wind energy costs may evolve with future technologies or how innovations that impact particular cost categories can drive future reductions in LCOE.

In this research, we conduct a detailed system-level analysis to provide a more comprehensive understanding of how wind turbine and plant upsizing impacts the costs of a representative fixed-bottom Atlantic Coast offshore wind energy project. We draw from separate bottom-up models for BOS costs, O&M costs, and annual energy production (AEP) to compute LCOE under a range of turbine and plant capacity scenarios, which is the primary originality of this study. We establish a baseline set of technological assumptions and quantitatively characterize the cost impacts that can be attributed to economies of size (resulting from increased turbine rating) and scale (resulting from larger plant capacity). Although a number of exogenous factors could further affect the cost reductions outlined in this article, such as supply-chain efficiencies [24] and the introduction of novel technologies [25], these results establish a baseline that can be achieved through wind turbine and plant upsizing only. We report these cost sensitivities at a component level, which identifies the underlying sources of the overall changes in LCOE and will facilitate future research to target innovations in key cost categories that can have the most significant impact on LCOE. This can support policymakers, project developers, and funding agencies in exploring critical cost–benefit trade-offs and evaluating the impact of novel technologies. Most importantly, through the novel, coupled, bottom-up modeling process implemented in this study, we demonstrate the system-level cost advantages of higher turbine ratings and larger plant sizes for offshore wind energy projects and use these results to provide insights into the challenges and opportunities presented by upsizing. Our results suggest that wind turbine and plant upsizing are important drivers of past and future cost reductions.

2. Methodology

2.1. Background and approach

LCOE represents the life cycle unit costs of a power plant and is the primary metric used to compare the value of different generation sources, as it balances costs with energy production [26]. The calculation of LCOE follows [27], as defined in Eq. (1), and captures the impact of project investment and finance, overnight capital costs, annual maintenance costs, and annual energy production:

$$LCOE = \frac{FCR\left(C_{\text{turbine}} + C_{\text{BOS}}\right) + C_{\text{O\&M}}}{NCF \times 8760}, \tag{1}$$

where $LCOE$ is the levelized cost of energy ($/MWh); FCR is the fixed charge rate that annualizes the upfront project capital cost, accounting for return on debt and equity, taxes, and the expected financial life of the project (%/year); C_{turbine} are the wind turbine capital expenditures ($/kW); C_{BOS} are the BOS capital expenditures ($/kW); $C_{\text{O\&M}}$ are the annualized O&M expenditures ($/kW-year); and NCF is the net capacity factor (scaled by the 8760 h in a year).

As wind turbines and plant sizes grow for future offshore wind energy deployments, developers will leverage a myriad of technological innovations and site-specific project designs to drive costs even lower than the basic upsizing impacts. The results presented in this article strive to control for these effects by maintaining consistent technological, logistical, and financial assumptions for every scenario; for instance, this article does not consider bulk discounts for larger volume orders, optimize power plant layouts for maximum energy production, or customize export systems for a particular plant capacity, and it assumes turbine capital costs remain constant for increasing ratings. In some cases, physical constraints dictate that the scenario definitions must be changed; for example, as the size of the wind turbine increases, a larger installation vessel is required to lift components to hub height. However, the majority of the input assumptions are retained throughout the scenarios. This approach provides a conservative baseline for the cost reduction impacts of turbine and plant upsizing that can potentially be enhanced by the introduction of technological, process, or financial improvements.

This analysis applies bottom-up modeling approaches to determine how increased wind turbine ratings and larger plant sizes drive design and cost changes in the capital expenditures (CapEx), operational expenditures (OpEx, or O&M costs), and AEP of a reference fixed-bottom offshore wind power plant that is broadly representative of the site conditions of a typical project on the U.S. Atlantic Coast. Although LCOE is also sensitive to the financial structure of a project [28], the scope of this analysis focuses on the direct impact of technological decisions on cost, and we therefore hold FCR constant. The following sections describe the modeling approaches, scenarios, assumptions, and limitations used to evaluate the individual terms of Eq. (1) and to quantify the overall effect on LCOE. It is important to note that, because the intermediate outputs of these design tools (such as monopile size, vessel utilization, number of component failures per year, and wake losses within the plant), scale with turbine and plant size, the cost and performance results presented in Section 3 implicitly contain the coupled effects of upsizing on LCOE.

2.2. Models

We use three models to evaluate different terms within Eq. (1). We compute BOS costs using the Offshore Renewables Balance-of-system Installation Tool (ORBIT), a process-based simulation model developed by NREL that assesses capital and installation costs for fixed-bottom or floating offshore wind energy projects [29]. ORBIT is a flexible analysis tool that allows users to define a range of project scenarios, vessels, weather conditions, and installation scenarios. The wind power plant construction is simulated on an hourly basis using an input wind and wave time series to model the accrual of weather delays when the current conditions exceed the prescribed operational limits of the vessels. Other models utilize time series simulation, such as Kikuchi and Ishihara [30], who compared different construction methods for a fixed-bottom wind plant to predict weather downtime using hindcast wind and wave data sets, or Paterson et al. [31], who compared performance and downtime of different vessel spreads to evaluate offshore wind installation risk. ORBIT provides additional flexibility to define novel strategies and technology choices. ORBIT contains simple sizing modules that determine how component sizes and costs scale with project parameters, such as wind turbine rating, water depth, and distance to shore. The assumptions, methodology, and baseline results of ORBIT have been reviewed by industry partners and compared against similar models to verify its accuracy. Unless otherwise noted, the underlying data for the model are taken from previous NREL analyses conducted by Beiter et al. [32] and Maness et al. [23] and updated through an industry review process to reflect cost and technology advancements. This limited validation of the input data is a result of its proprietary or project-specific nature, and introduces an element of uncertainty into the results; however, the review process confirms that the values are broadly realistic for offshore wind energy projects. As a result, the cost trends reported in this study are defensible, although the exact values may vary for projects with different characteristics. Nunemaker et al. [29] provide a detailed description of the underlying functionality and theory of ORBIT, and the open-source code base can be found at https://github.com/WISDEM/ORBIT/.

We evaluate OpEx costs using the Shoreline O&M Design model, an industry-standard tool used to estimate costs, availability, and resource utilization for the O&M phase of an offshore wind energy project [33]. Shoreline O&M Design is an agent-based model that allows a user to define project technical specifications, weather time series, vessel characteristics, component failure probabilities, and OpEx strategies. In agent-based models, system elements such as wind turbines or repair vessels are represented as agents whose actions are determined by behavioral rules [34]. The agents interact within the simulation environment, which includes wind and wave time series and geographic data. Agents implement predefined maintenance, repair, or replacement strategies for both scheduled and unscheduled maintenance throughout the simulated project lifetime. Shoreline aggregates the overall lifetime O&M costs and breaks them down into personnel, port, transportation, and scheduled/unscheduled maintenance costs; in addition, time-based and production-based availability are reported.

Finally, we compute the AEP of the various project scenarios using FLOw Redirection and Induction in Steady State (FLORIS), a computationally inexpensive steady-state engineering wake modeling toolbox [35]. Using FLORIS, a particular plant layout can be defined and populated with wind turbines defined by power and thrust curves, hub heights, rotor diameters, and other simple parameters. The flow through the wind power plant is represented by choices from commonly used velocity deficit, wake combination, and wake deflection models. Annual energy production and wake losses can be computed for a given wind resource and plant configuration.

A flowchart depicting the models used in this analysis, along with the key inputs provided to each model and the assumed turbine and soft costs, is shown in Fig. 2.

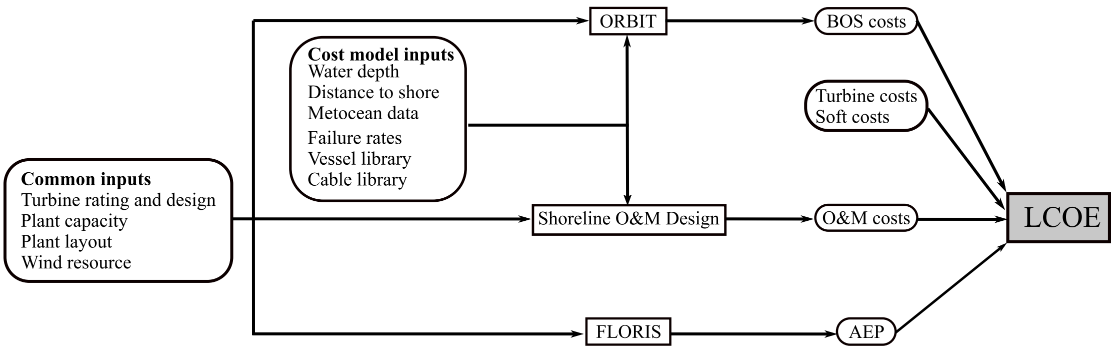

Fig. 2. Flowchart showing the inputs to the ORBIT, Shoreline O&M Design, and FLORIS models and the LCOE computation process.

Table 1
Major technological and geospatial parameters for the baseline fixed-bottom offshore wind project. Values for the capacity-weighted global average project installed in 2019 are also reported [36].

	Stehly et al. [36]	Current study
Region	North Atlantic	North Atlantic
Turbine rating, MW	6.1	6
Wind plant capacity, MW	600	500
Water depth, m	34	34
Substructure type	Monopile	Monopile
Export cable route distance, km	50	50
Distance to operations port, km	Not reported	116
Average 100-m wind speed, m/s	Not reported	9.0
Average significant wave height, m	Not reported	1.4
Turbine-scaling scenarios, MW	N/A	6, 8, 10, 12, 15, 18, 20
Plant-scaling scenarios, MW	N/A	250, 500, 750, 1000, 1250, 1500, 1750, 2000, 2250, 2500

Table 2
Cost and sizing parameters for increasing wind turbine ratings.

	Windturbine rating, MW						
	6	8	10	12	15	18	20
Capital cost, \$/kW				1300			
Rotor diameter, m	151	175	196	215	240	263	277
Hub height, m	106	118	128	138	150	161	169
Blade mass, t	22	32	43	54	72	91	103
Blade footprint, m^2	192	258	320	381	480	581	634
Nacelle mass, t	262	369	483	604	797	1003	1147
Nacelle footprint, m^2	125	151	177	203	242	281	307
Tower section mass, t	230	288	344	399	480	560	613
Tower section diameter, m	8	8	8	8	10	10	10

Blades are assumed to be transported in 3-by-3 stacks on a vessel.

2.3. Scenario and reference plant definitions

We evaluate the impacts of upsizing for a wind turbine size between 6 and 20 MW and a project size between 250 and 2500 MW. We chose the lower end of these ranges because they correspond roughly to the average wind turbine and plant size globally in 2019 (Section 1).[2] The upper end represents turbine and plant sizes that we consider attainable for new installations by the early- to mid-2030s, as surveyed in a recent elicitation of global experts [37]. We chose monopiles as the representative substructure in our model because they are used in more than 75% of all operating offshore wind energy projects globally at the end of 2019 [10].

The cost reductions are defined relative to a baseline project representative of the capacity-weighted average project installed in 2019, the most recent year for which data are available [36]. We have made several minor variations to define the baseline project used in this study; specifically, the baseline wind turbine rating and plant capacity have been adjusted to fit into the chosen sequence of upsizing scenarios. The modeling tools required for this analysis also require several additional parameters to be defined that are not specified in [36], including a 34-year wind and wave time series with hourly resolution taken at a representative point in the North Atlantic (41°N, 71°W) pulled from the ERA5 reanalysis data set at a 100-m measurement height [38]. Table 1 defines the baseline project parameters, along with the original values used by Stehly et al. [36]. In this study, we only evaluate the wind turbine and plant upsizing results at this reference site; although the sensitivity of LCOE to these parameters will likely change at different sites [28], the trends reported should be consistent for different projects. As a result, although the baseline project used in this study is drawn from site conditions in the United States, the resulting cost trends are broadly applicable to the global offshore wind industry as the cost, technology, and process assumptions are representative of the entire industry.

2.4. Wind turbine cost and sizing

The wind turbine represents around 30% of the overall CapEx costs for a typical fixed-bottom offshore wind project [36]; however, these costs are negotiated on an individual project basis and are typically kept confidential by the supplier and developer [10]. As a result, publicly available data sources for wind turbine pricing report a broad spread of CapEx estimates, with some sources predicting a 15% decrease between 2019 and 2025 [25], whereas others expect to see a slight increase in costs over the same time period [39]. Furthermore, many of these reports do not explicitly align turbine CapEx with nameplate capacity. As a result, this analysis considers a constant capital cost of \$1300/kW [36], meaning that the reported cost reductions are achievable without any reductions in wind turbine CapEx. Technological innovations, such as improved materials or manufacturing processes that reduce turbine costs, will provide an additional benefit to LCOE.

[2] While the global average power plant size is 400 MW as of 2019 (Section 1), we decided to use a lower threshold of 250 MW because the average is skewed by a few very large projects.

Table 3
Monopile and transition piece sizing parameters for increasing wind turbine ratings.Costs are ORBIT default values, and the mass and geometry values are ORBIT outputs.

	Turbine rating, MW						
	6	8	10	12	15	18	20
Monopile capital cost, $/t				2250			
Transition piece capital cost, $/t				3230			
Monopile diameter, m	7.3	8.3	9.0	9.7	10.6	11.5	12.0
Monopile length, m	72.6	75.4	77.7	79.8	82.3	84.6	86.1
Monopile mass, t	576.2	750.5	920.0	1093.3	1338.7	1587.0	1758.1
Transition piece length, m				15			
Transition piece mass, t	241.9	303.4	360.9	417.8	495.5	571.6	622.6

Although wind turbine costs are maintained as constant in this analysis, the increasing size of higher-nameplate turbines constrains the type of vessel that can load or lift the turbine components during installation or maintenance. This constraint may result in fewer turbine sets being loaded on a vessel during loadout at port, or may require a larger vessel with the lifting capacity to install components weighing hundreds of tonnes at hub heights above 150 m. In order to consider these effects, we estimate the masses and footprints on deck of critical wind turbine components (e.g., blades, nacelle, and tower) based on publicly available data on commercial turbines [40] and reference turbines with power ratings of 10 MW [41], 15 MW [42], and 20 MW [43]. We draw blade masses from a linear fit to the data, and compute a rectangular footprint as the product of the blade length and chord. We estimate nacelle masses using the NREL Cost and Scaling Model [44] and extrapolate footprints from publicly available data for commercial machines. Towers are assumed to have two sections and diameters of 8 m for wind turbines up to 12 MW, and 10 m for larger turbines; we compute the corresponding section footprints as the area of the circular cross section, which assumes the tower sections will be transported in a vertical configuration. The hub height is defined to maintain a 30-m clearance between the mean water line and the lowest point of the blade-tip passage. Finally, we directly scale power and thrust curves for each machine from the International Energy Agency 15-MW reference wind turbine [42]. Table 2 defines the resulting generic wind turbine parameters.

2.5. Balance-of-system costs

As described in Section 2.2, we use the ORBIT model to evaluate BOS capital and installation costs. The following sections describe key assumptions and design choices for the various cost components used for the different scenarios. We derive individual component specifications such as cost rates from publicly available literature and calibrate them with feedback from industry collaborators; the values presented here are aggregated from different available sources to protect any confidential data.

2.5.1. Monopile design

ORBIT implements a monopile design process based on work by Arany et al. [45], which scales the monopile length, diameter, and mass based on water depth, turbine rating, and wind speed. The simplified representation in ORBIT is predicated on conservative engineering safety factors instead of design optimization, and therefore skews toward larger designs for higher turbine wind ratings than would be achieved in practice. ORBIT also produces a transition piece design based on relationships taken from [45]. Table 3 provides the monopile designs produced by ORBIT for increasing turbine ratings.

2.5.2. Electrical infrastructure

ORBIT allows users to define multiple types of interarray cables used to make up individual strings of wind turbines; the model adds turbines to each cable type within the string until the overall power capacity cannot support any additional turbines. The strings are then connected to the offshore substation in a radial pattern. Table 4 provides the specifications for the two types of 66-kV array cables used in this study; the same two types of cable are used for all wind-turbine and plant-scaling scenarios.

Table 4
Array and export cable specifications. Costs, current ratings, and burial depths are ORBIT default values for the specified cable ratings.

	Conductor size, mm^2		
	185	630	1000
Application	Array	Array	Export
Rated voltage, kV	66	66	220
Current rating at 2-m burial depth, A	445	775	900
Linear density, t/km	26.1	42.5	90
Unit cost, $/km	200,000	350,000	850,000

All project scenarios use a single design for the export cable; Table 4 also lists these specifications. This assumption differs from current industry practice, in which export cables are custom designed for a specific project based on plant capacity, distance from shore, and seafloor conditions; in actuality, planned project sizes can be dictated by the availability of export cable capacities. Using the same cable for all projects is a simplifying assumption resulting in underoptimized export system designs across the scenarios; Section 3.2 discusses the impact of this assumption on project costs.

The final components of the electrical infrastructure modeled in ORBIT are the offshore and onshore substations. ORBIT parameterizes the costs of these components in terms of plant capacity, grid interconnection voltage, and the unit costs of power transformers, switchgear, and power compensation devices [29]. We define the number of substations to align with empirical data from projects installed in the last 5 years [46]. Table 5 lists the number of identical substations specified for each plant capacity along with the number of export cables that ORBIT calculates are required to offtake the maximum power produced by the wind plant.

2.5.3. Vessel characteristics

The installation and O&M phase simulations consider seven vessel types: jack-up wind turbine installation vessel (WTIV), heavy lift vessel (HLV), cable lay vessel (CLV), scour protection installation vessel (SPIV), crew transfer vessel (CTV), and feeder barge (FB). Each of these vessels has specific project tasks, loading capacities, and transit and installation weather constraints. Table 6 provides the defined characteristics of each vessel. Nunemaker et al. [29] provide detailed installation procedures for each phase. The simulation start date is set at May 1 to avoid pile-driving restrictions during the migration season of the North Atlantic right whale [47]. The simulation is conducted for a single weather time series beginning in the year 2000, which has wind and wave statistics similar to the entire 34-year data set.

An exception to the assumption of constant technologies throughout all scenarios is required for wind turbine ratings above 10 MW, as modern WTIVs typically do not have the crane capabilities to lift components to the hub height of 138 m used in this study. As a result, turbines with ratings at or above 12 MW require a hypothetical future WTIV with a higher lifting capacity and hook height; the transit, cargo,

Table 5
Export system design for increasing plant capacities. The number of offshore substations is an input assumption and the number of export cables are computed by ORBIT to support the plant capacity for each scenario.

	Plant capacity, MW									
	250	500	750	1000	1250	1500	1750	2000	2250	2500
Offshore substations	1	2	2	2	3	3	4	4	4	5
Export cables	1	2	3	3	4	5	6	6	7	8

and weather-limit specifications are assumed to be the same as the generic WTIV listed in Table 6, although a 25% premium is added to the charter rate to account for the exclusive capabilities of the new vessel.

2.6. Operations and maintenance costs

Inputs to the Shoreline O&M Design model were derived from the baseline fixed-bottom O&M project outlined in [48]. Table 7 provides input assumptions for each maintenance type. The modeled offshore substation O&M costs depend on the number of transformers; one transformer is added for every 250 MW of plant capacity, which is also used in the ORBIT model. Annual service and inspections are preventive maintenance tasks and all other tasks are corrective. Repair costs include spare parts and consumables. We increased the number of remote resets and decreased manual resets relative to Smart et al. [48] to reflect increasing adoption of remote maintenance capabilities.

The model requires specified failure rates and repair strategies for major plant components; modeling of cable failures had not been implemented in the Shoreline O&M Design model when this study was conducted. The time between failures is calculated using an exponential distribution based on a Weibull function with a constant scale parameter that is the inverse of the failure rate in Table 7. This analysis assumes a fixed operations cost of $32/kW/yr, which includes project management, insurance, monitoring and forecasting, and environmental health and safety compliance. The number of technicians in each scenario is determined based on one technician for every four turbines in the wind plant, with 12-hour workshifts between 7 a.m. and 7 p.m. CTVs are used for most maintenance tasks and each scenario has as many CTVs as are required to provide seats for all technicians. Major replacements require a jack-up WTIV to be chartered, which contributes significantly to overall costs. As the number of wind turbines (and therefore the number of major replacements) increases, additional WTIVs are assumed to be available to perform repairs to maintain the availability of the plant at above 95%. An additional WTIV is mobilized for every 150 wind turbines in the project. The resulting scenarios are simulated for a period of 25 years using the same ERA5 weather time series from the ORBIT model runs.

2.7. Annual energy production

The final sensitivity to LCOE considered in this analysis is the impact of AEP, which is computed for a range of scenarios using FLORIS. The wake loss and energy production of a given power plant are highly dependent on the wind resource and the layout of the individual wind turbines, leading to challenges in the model setup, as most scenarios in this analysis have different numbers of turbines. We addressed this by running FLORIS for a baseline set of 49 scenarios within the design space where the combination of plant capacity and turbine rating corresponded to a perfect square number of turbines; in other words, we used FLORIS to compute the AEP for scenarios that formed a square grid. Row and wind turbine spacing were set at 7 rotor diameters (7D), and the plant boundaries were allowed to grow to accommodate larger plants. We used a Gaussian velocity deficit model and sum of squares wake combination model to evaluate the flow through the wind plants. Results for the actual scenarios specified in Table 1 were then interpolated from the computed data, resulting in a maximum relative error of around 5%, but satisfactorily smoothed the AEP variations over the design space. The data points in the design space corresponding to the square grids are plotted in Fig. 3. The same wind resource data used for the ORBIT and Shoreline model runs are used to create wind roses at the respective hub heights of each turbine in the analysis; a wind rose at 100 m above sea level from this data set is also provided in Fig. 3.

2.8. Key assumptions and study limitations

Previous sections describe the major assumptions and caveats of this analysis, which are summarized here for convenience. Section 4 discusses the impact of these constraints and the opportunities they present for realizing additional cost reductions.

1. Turbine capital costs per kilowatt are held constant for all scenarios.
2. A hypothetical WTIV is assumed to exist that can install 12–20-MW wind turbines.
3. Export cable characteristics are not customized for a given plant capacity; instead, more (identical) cables are added to support larger projects.
4. Economies of scale attributed to quantity discounts, supply chain improvements, or amortizing of management costs for larger projects are not considered.
5. The same number of installation vessels are used for all project sizes.
6. Wind turbine failure rates are assumed to remain constant for all nameplate capacities.
7. Cable failures are not modeled in the Shoreline O&M Design tool.
8. Deterministic values of the input data are used to demonstrate cost trends, but the uncertainty surrounding these assumptions are not quantified.

3. Results and discussion

The methodology described in Section 2 was used to generate results over the design space of wind turbine ratings and plant capacities. This section presents a detailed analysis of component-level CapEx reductions along with a summary of OpEx cost reductions for the turbine upsizing scenarios (as the OpEx costs described in Section 2.6 scale with the number of wind turbines, the costs do not change significantly on a $/kW basis for the plant upsizing scenarios and are not presented here). We also present a summary of changes in AEP and wake losses for both turbine and plant upsizing scenarios. The section concludes with top-level cost reduction results over the entire design space. A number of key assumptions and constraints are examined to provide additional insight into how technological or logistic enablers can overcome these challenges and allow the offshore wind industry to achieve, or exceed, the reported cost reductions.

3.1. Impact of turbine upsizing

3.1.1. Balance-of-system cost reductions

This section focuses on the cost impacts of turbine upsizing while holding the plant capacity constant at 1000 MW; the trends in these results are similar for all plant capacities considered in this analysis. Fig. 1 shows results for the scaling effects of the overall BOS costs as breakdowns of the individual cost categories. The BOS costs decrease monotonically from $1103.4/kW to $873.6/kW as wind turbine rating

Table 6
Vessel characteristics used for the simulated installation and O&M phases of each project. All parameters are ORBIT default values.

	Vessel type					
	WTIV	HLV	CLV	SPIV	CTV	FB
Project phases	Monopile, turbine, O&M	Offshore substation	Array and export cables	Scour protection	O&M	Monopile, turbine, substation
Number per phase	1	1	1	1	Varies	2
Transit speed, km/hr	10	7	6	6	40	6
Transit wind speed limit, m/s	3	20	15	20	25	15
Transit wave height limit, m	20	2.5	2.5	2	3	2.5
Install wind speed limit, m/s	15	15	N/A	N/A	16	N/A
Install wave height limit, m	2	2	2.5	N/A	1.8	N/A
Cable lay speed, km/hr	N/A	N/A	0.2	N/A	N/A	N/A
Cargo, t	8000	8000	4000	10,000	N/A	3500
Deck space, m^2	4000	4000	N/A	600	N/A	4200
Number of O&M technicians	N/A	N/A	N/A	N/A	12	N/A
Mobilization time, days	7	7	7	7	0	7
Charter rate, $1000/day	225	500	140	120	4	100

Table 7
Operations and maintenance input assumptions derived from [48].

	Failure rate, #/year/asset	Vessel	Repair time, h	Technicians	Parts cost
Turbines					
Annual service	1	CTV	50	3	0.08%
Remote reset	10	n/a	2	n/a	
Manual reset	2	CTV	3	2	
Minor repair	3	CTV	7.5	3	0.09%
Major repair	0.3	CTV	22	4	0.50%
Major replacement	0.11	WTIV	34	n/a	7.55%
Offshore substation					
Annual inspection	1	CTV	30	3	
Small transformer repair	0.45	CTV	8	3	$5000
Large transformer repair	0.05	CTV	48	4	$250,000

Wind turbine repair costs are reported as a percent of turbine CapEx, whereas substation repairs are reported in absolute values.

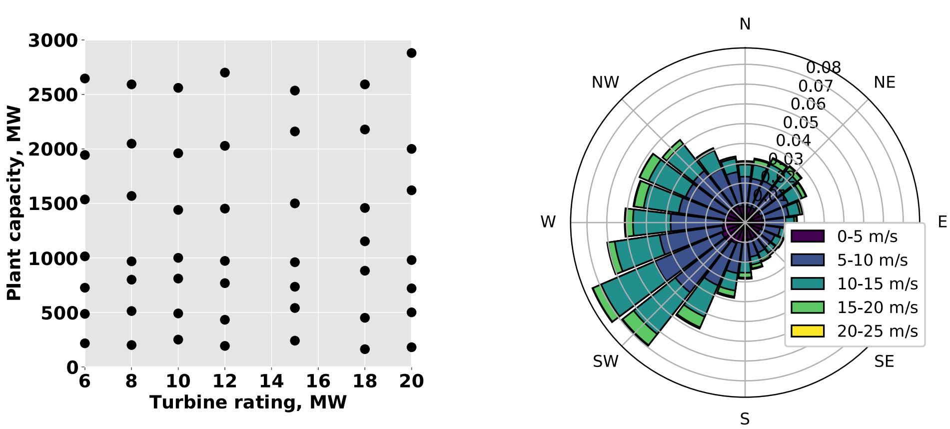

Fig. 3. Square-grid plant and wind turbine scenarios (left) and a wind rose at a 100-m hub height for the reference project (right) used for FLORIS runs. Energy production values for project scenarios listed in Table 1 are interpolated between the square-grid scenarios.

increases from 6 MW to 20 MW. The curve does not converge to a minimum cost within this design space, suggesting that further cost reductions could be realized for larger turbines as the number of required components, such as substructures and cables, continues to decrease.

Fig. 5 shows the percent reduction in individual categories that comprise the balance-of-system costs; categories, such as export cable costs, which do not scale with turbine rating, are not shown. The capital cost of the monopile decreases by 13.7% between turbine ratings of 6 MW and 20 MW, as the substructure system size and cost (which includes the transition piece and scour protection) grow more slowly than the increase in wind turbine rating. Because the monopile comprises a high percentage of the BOS costs [36], the reduction contributes significantly to the overall cost decrease. Optimized designs for larger turbine ratings that improve on the simple sizing tools in ORBIT may be able to realize additional benefits. The capital cost of the array cables decreases by more than 50%, as fewer turbines require less connecting cabling. This percent reduction does begin to level off at higher turbine ratings, as the 7D spacing between turbines mandated to reduce wake effects increases the cable length between individual machines.

Installation costs for wind turbine, monopile, and array cable installation all decrease for larger wind turbines. Some localized increases in costs are noticeable, such as for installing 18-MW turbines and monopiles for 15-MW turbines. These occur as a result of step changes in the number of component sets that can fit on a feeder barge; for example, the feeder barge defined in Table 6 can fit two sets of

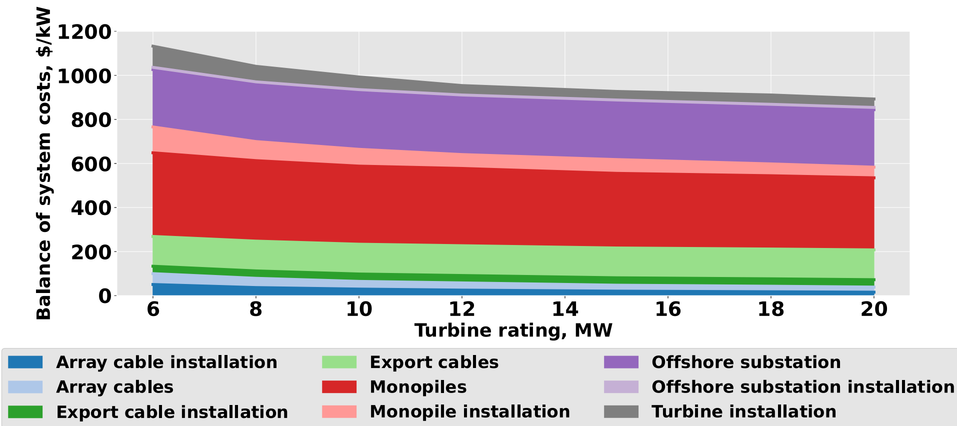

Fig. 4. Effects of turbine upsizing on balance-of-system costs for a constant plant capacity of 1000 MW. Results are shown as a breakdown of cost magnitudes in each cost category.

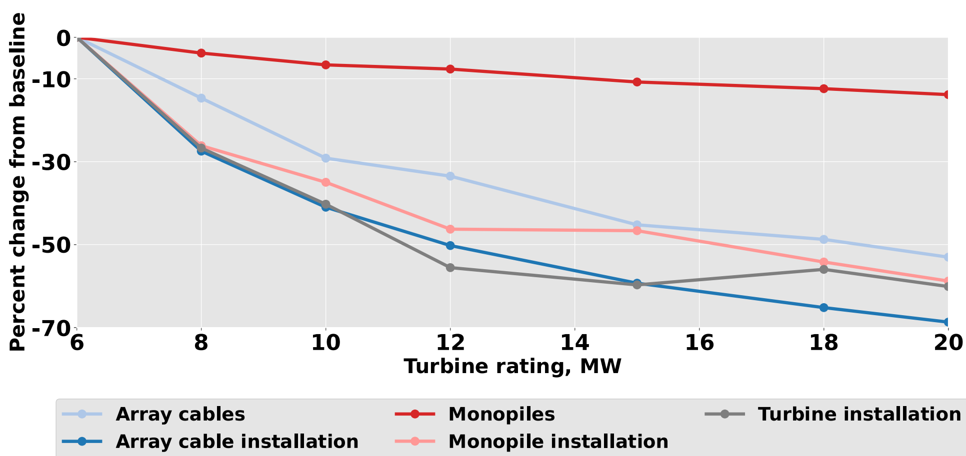

Fig. 5. Effects of turbine upsizing on BOS costs for a constant plant capacity of 1000 MW. Results are shown as a percentage of the baseline project costs from Table 1. Cost categories such as export cables that do not scale with turbine rating are not shown.

monopiles and transition pieces for the 12-MW scenario but only one set in the 15-MW scenario. This capacity constraint results in additional delays for the latter case, as the WTIV spends more time waiting for components to arrive on-site. Although these specific increases highly depend on the vessel characteristics used in this study, they identify some of the additional logistical constraints associated with turbine upsizing and suggest an opportunity for developers to optimize costs for these type of scenarios by contracting additional feeder barges or investing in vessels with greater loadout capacities.

The natural interpretation of the results in Figs. 4–5 is that project CapEx should continue its recent decreasing trend as wind turbine sizes continue to grow [10]. An alternative viewpoint is that this conclusion provides a safety net for developers planning projects around larger turbines currently under development with uncertain procurement costs. Provided that these costs do not increase more than the BOS savings resulting from turbine upsizing, a developer can expect to at least break even on capital costs. Either way, the results in this article suggest that the current trend of increasing wind turbine nameplate capacities can continue beyond the 20-MW horizon.

The trend in decreasing BOS costs for higher turbine ratings is based on the assumption that a vessel exists that can install these larger machines. For the industry to achieve these BOS cost reductions, it is therefore critical to support the development of next-generation installation vessels that will enable deployment of large wind turbines. Investment in these vessels has historically been challenging, as the 2- to 3-year lag between conceptual design and commissioning makes it difficult to predict the size of turbine the vessel should be built for [49]; however, the results of this study suggest that vessel manufacturers should anticipate continued increases in turbine ratings and design or retrofit vessels accordingly.

3.1.2. Operations and maintenance cost reductions

Fig. 6 plots the decreasing operational expenditures attributed to increased wind turbine rating, along with the component of overall O&M costs spent on service vessels. Because the number of failures per year defined in Table 7 scales with the number of assets in the wind power plant, increasing the turbine rating reduces the number of repairs required, as fewer turbines results in fewer failures. The subsequent decrease in vessel costs drives the reduction in total costs, as shown in Fig. 6. Because the number of failures is inversely proportional to the number of turbines, the cost reduction curve shows diminishing returns as the turbine rating continues to increase. This result differs from the BOS costs reported in Fig. 4, which indicates that balance-of-system costs do not run into a lower bound for wind turbines up to 20 MW.

A potential high-impact area for technological innovation is apparent from the asymptotic behavior of O&M vessel costs reported in Fig. 6, as the convergence of vessel costs prevents further decreases in overall O&M costs as turbine sizes increase. Introduction of digitalization strategies such as predictive analytics, condition monitoring, digital twins, risk-based decision making, or remote inspections could reduce the need for expensive trips to the site. These innovations could also

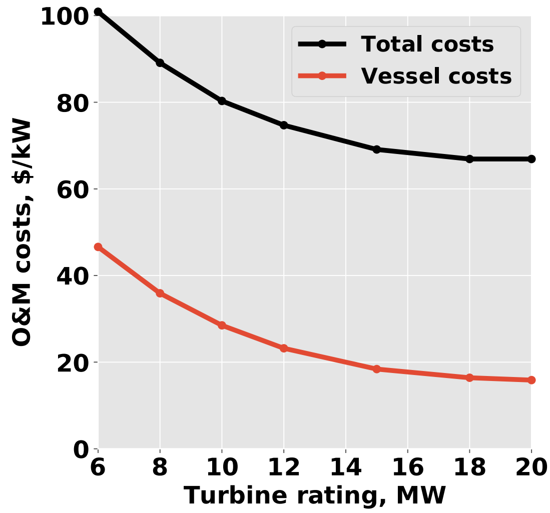

Fig. 6. Effects of turbine upsizing on operations and maintenance costs of a 1000-MW plant. Total cost reductions are primarily driven by the decreased vessel demand to service fewer turbines with higher rated power.

contribute to lowering nonvessel O&M costs by reducing labor requirements and avoiding some unscheduled maintenance events, with the result of driving down O&M costs beyond the curves shown in Fig. 6.

3.2. Impact of plant upsizing

Fig. 7 shows the effects of increasing the plant capacity on balance-of-system costs. Overall BOS costs decrease from $1153.8/kW for a 250-MW plant to $973.9/kW for a 2500-MW plant; the bulk of this cost reduction occurs between 250 MW and 1000 MW, with diminishing returns above 1000 MW. The assumptions that constrain the modeling approach described in Section 2 suggest that this is a conservative estimate; actual projects may be able to realize additional cost reductions by optimizing the export system design, obtaining bulk component pricing for larger orders, and amortizing project management costs over larger numbers of wind turbines. The results in Fig. 7 represent the achievable benefits if each scenario maintains a nominally constant set of technology assumptions.

Fig. 8 shows that the most significant reductions in capital costs are found for the export cables and offshore substation. The costs of the export cable bounce between 0% and 25% cost reductions from the baseline project. These nonmonotonic variations occur as a function of the number of export cables required to support the plant capacity, listed in Table 5. For most increases in plant capacity, an additional export cable is required to offtake the increased power; however, three of the export cables specified in Table 4 are sufficient to support both 750-MW and 1000-MW plants, so no new cable is required and the costs are better amortized over the larger project. This leads to the dip in the cable costs reported in Fig. 8. The same trend occurs between 1750 and 2000 MW plants. Although these particular breakpoints are specific to the cable technology defined in this study, it is an important indication that the export cable capacity should be optimized for a particular project.

The introduction of key innovations or optimized project designs can be expected to enhance the baseline cost reductions reported in this study. Several areas that would benefit from increased investment or research and development can be identified. High-voltage direct current (HVDC) export systems for larger projects could offtake 2 GW of power with fewer cables than the high-voltage alternating current (HVAC) cables used in this study [50]. Furthermore, some studies indicate that HVDC cable costs may not be substantially higher than HVAC cables, although substation costs may be roughly double that of an HVAC substation [51]. Although HVDC systems have been proposed for far-offshore projects, as they reduce reactive power losses relative to HVAC transmission, the cost trends presented in Fig. 8 suggest that implementing them for nearshore, high-capacity projects could achieve additional cost reductions relative to the baseline results presented in this study.

The installation costs for different project phases also show decreasing trends as plant size increases. Export cable and offshore substation installation costs decrease consistently, although they do not represent a significant portion of the overall project costs. The variation of monopile, wind turbine, and array cable installation costs reflects the impact of weather delays on each phase. All costs initially decrease as they are amortized over larger projects, but then monopile (including transition piece and scour protection) and array cable installation costs begin to increase as the overall phase duration moves into the winter season and weather delays become more prevalent. The wind turbine installation, which requires a shorter duration than the other phases, can be completed in the summer season even for the largest projects, and the associated costs therefore decrease monotonically. Although the cost increases of the monopile and array cable installations do not drastically increase the overall BOS costs, as shown in Fig. 7, these scenarios offer an opportunity for project developers to mitigate construction risk by contracting additional vessels or splitting the installation into multiple seasons.

3.3. Improvements in annual energy production

Fig. 9 shows the range of annual energy production values and corresponding wake losses for increasing turbine rating and plant capacity. For a given plant capacity, AEP increases with the turbine rating because fewer wind turbines result in lower wake losses. This results in AEP improvements of between 6.6% and 9.6%, as turbine rating increases from 6 MW to 20 MW for the range of plant sizes considered. In this study, we do not constrain the spatial boundaries of the wind power plant for the AEP model. In reality, using fewer, larger turbines in a fixed space may provide additional benefits as the higher number of low-rated-power machines would also have to fit within this same area and potentially increase wake losses. Increasing plant size while keeping wind turbine rating constant adversely affects the energy production as the higher number of turbines generates greater wake loss, effectively placing an upper bound on the relative increases in AEP.

3.4. Cost reduction summary

The cost reductions realized through plant and wind turbine upsizing are shown as contour plots in Fig. 10 for BOS costs, O&M costs, and LCOE. The results are presented as the percent variation from the baseline project defined in Table 1. Overall project CapEx, which includes the turbine CapEx, soft costs, and development costs that are held constant for all scenarios, is not plotted but follow the same trends as the BOS cost plot. While the AEP also varies over the design space, the deviation from the baseline is small relative to the variation observed in the BOS costs, O&M costs, and LCOE, and the results are not shown.

The components of the LCOE equation demonstrate different trends as plant and turbine size vary. Increasing both plant and turbine sizes produces complementary effects on the balance-of-system costs, resulting in a minimum cost for the combination of the largest projects and biggest turbines. O&M costs are less impacted by project size but decrease significantly as turbine rating increases for a given plant capacity, corresponding to fewer turbines and reduced servicing requirements. AEP also demonstrates beneficial effects as the wind turbine rating increases, but is penalized as the plant size increases, as increasing the number of turbines produces more wakes and additional losses; therefore, the most favorable AEP conditions exist for large

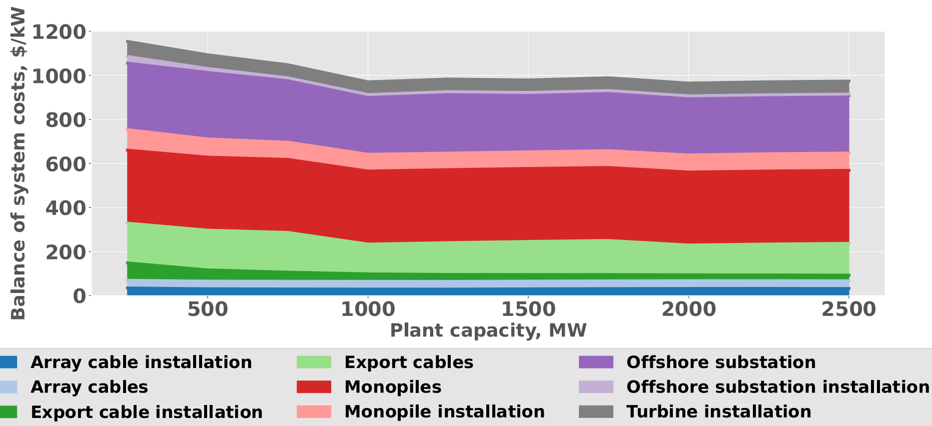

Fig. 7. Effects of plant upsizing on balance-of-system costs for a constant turbine rating of 10 MW. Results are shown as a breakdown of cost magnitudes in each cost category.

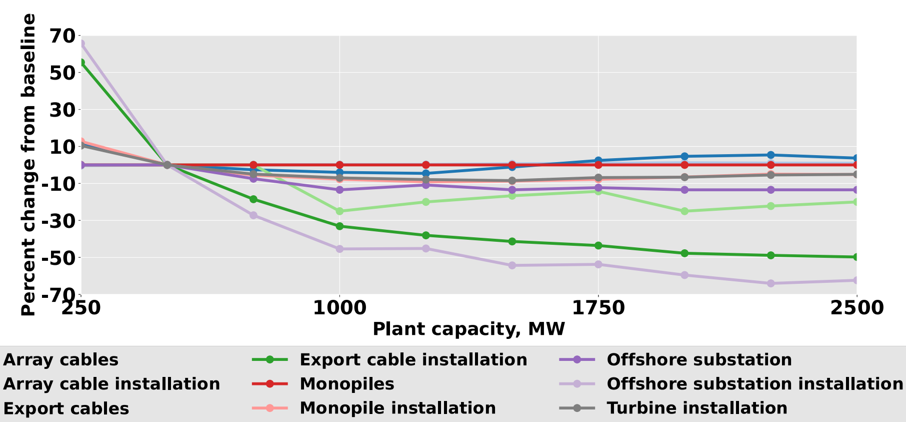

Fig. 8. Effects of plant upsizing on balance-of-system costs for a constant wind turbine rating of 10 MW. Results are shown as a percentage of the baseline project costs from Table 1.

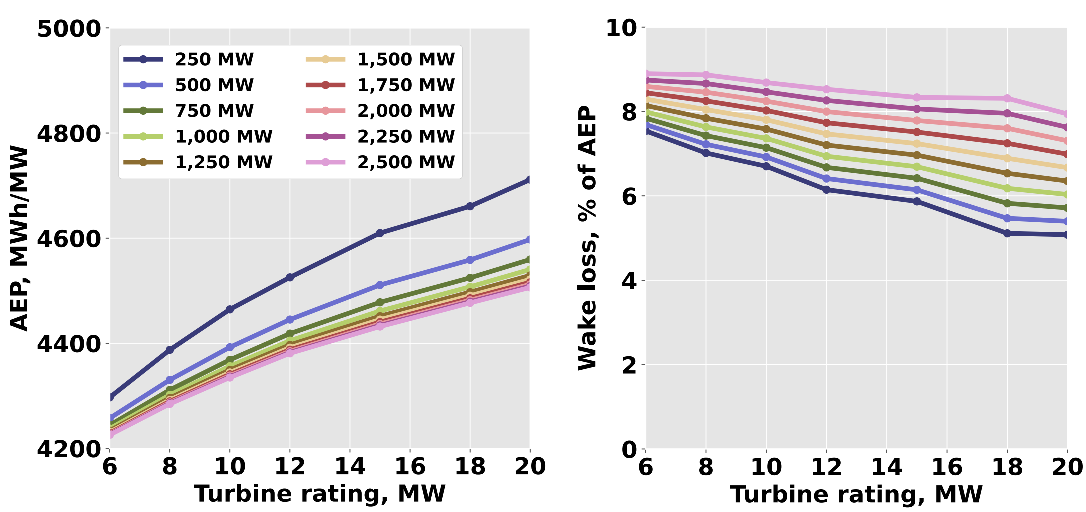

Fig. 9. Effects of wind turbine upsizing on annual energy performance (left) and wake losses (right) for plant sizes between 250 MW and 2500 MW.

turbines and small plant capacities. Combining these loosely correlated effects leads to the LCOE trends shown in Fig. 10, which show an approximately uniform decrease in cost with increasing turbine rating. Increasing plant capacity also contributes to reduced costs, although the effects are somewhat diminished as a result of competing effects of higher BOS costs and advantageous AEP at smaller plant capacities. The key conclusion to be drawn from Fig. 10 is that the highest turbine ratings and plant capacities lead to the lowest costs in the design space, with a reduction in LCOE of 23.6% from the baseline project. Although this trend is not surprising, the significant magnitude of the cost reduction is noteworthy, given that the suboptimal project designs assumed in this analysis can provide a significant opportunity to further decrease LCOE. Investment in higher-voltage or HVDC export cables, more efficiently designed monopiles (or different substructure topologies), and alternate installation strategies that eliminate the WTIV (such as self-erecting wind turbines) could allow the cost reductions reported

Table 8
Comparison of the baseline project and the lowest LCOE project. Turbine cost ($1300/kW) and (real) fixed charge rate (5.6%) are held constant for all scenarios.

	Baseline project	Minimum LCOE project	% Change
Turbine rating, MW	6	20	+233
Plant capacity, MW	500	2500	+500
BOS cost, $/kW	1224.3	866.9	−29.2
O&M cost, $/kW/yr	100.7	63.7	−36.7
AEP, MWh/MW/yr	4257.4	4506.2	+5.8
LCOE, $/MWh	69.8	53.3	−23.6

in Fig. 10 to continue their downward trend. For example, applying technologically driven cost reductions to monopiles (14.2%) or export cables (13%) anticipated by industry practitioners [25] results in approximately 5% and 2% reductions in the overall balance-of-system costs beyond those reported in Figs. 4 and 7, respectively. Additional discussion on the sensitivity of LCOE to constituent cost categories can be found in [28].

In order to provide some context for the percent cost reductions plotted in Fig. 10, Table 8 provides a direct comparison of the magnitudes of BOS and O&M costs, AEP, and LCOE with the values of the baseline project. The anticipated cost reduction to around $50/MWh is in reasonable agreement with projected offshore wind costs developed by various groups in the industry, which are aggregated and plotted in Fig. 1 [10]. Although a direct comparison between these results and those presented in Fig. 1 is difficult, as the exact costs of an offshore wind energy project are driven by project-specific conditions such as turbine and plant size, wind resource, water depth, and distance to shore, the general agreement in magnitude suggests that the 23.6% reduction in LCOE attributed to wind turbine and plant upsizing is a reasonable finding.

The primary conclusion of this analysis is that within our design space of 6–20 MW (turbine size) and 250–2500 MW (plant size) it is economically advantageous to select the largest available turbines and plant capacities. It is quite possible that an optimal configuration exists for fixed-bottom offshore wind. Previous efforts to identify such an optima based on physical or economic limits, such as mass scaling [15], cost of energy [14], or energy yield [16], have predicted maximum turbine ratings that have already been surpassed by today's turbine models [10]. These type of studies are useful to identify key cost and performance drivers; however, they also have two significant limitations. First, the identified configurations are specific to a particular system, whereas technological advancement may introduce new designs, materials, controllers, or logistics that supersede the constraints imposed on the optimized design. Second, a truly optimal design must extend beyond the wind turbine itself and consider balance-of system, operation and maintenance, supply chain, ports and vessels, interconnection, workforce, environmental, and stakeholder impacts. This study enhances the existing literature by modeling balance-of-system, operation and maintenance, and plant performance, yet we do not attempt to identify an optimal project design. Instead, we characterize the potential benefits to the costs of offshore wind energy if the technology and infrastructure conditions are available to support these projects, and lay the groundwork for future studies to explore the incremental impacts of additional system considerations on LCOE. Finally, these results can be used by supply chain contributors to anticipate future industry needs and develop appropriate capabilities to support broad offshore wind energy deployment.

4. Conclusions

We derived these cost results through a coupled modeling approach that assesses the impacts of plant and turbine upscaling on balance-of-system costs, operation and maintenance costs, annual energy production, and levelized cost of energy. Upsizing the wind turbine nameplate capacity from 6 MW to 20 MW while holding the plant capacity constant at 1000 MW resulted in a 20.8% decrease in balance-of-system costs and a 33.6% reduction in operational costs. These reductions were induced by a smaller number of required turbines and substructures and less frequent repair trips for a given plant capacity. Increasing the plant capacity from 250 MW to 2500 MW led to a 15.6% reduction in balance-of-system costs, as the export system costs were distributed more efficiently over a larger number of wind turbines. A number of investment opportunities were identified to enable or exceed these cost reductions, such as the development of next-generation installation vessels (or alternative installation methods) that can deploy large turbines, high-voltage direct-current export systems for large projects, and digitalization strategies for operation and maintenance that could reduce vessel requirements. Future work will involve more detailed analysis of these promising innovations, such as using the process-based modeling capabilities of ORBIT to conduct comparative analyses on the impacts of novel installation methods on project cost, weather downtime, and risk. Further enhancement of the ORBIT model to incorporate supply chain considerations such as manufacturing and port logistics will allow these studies to be more tightly coupled to the infrastructure requirements for commercial-scale offshore wind deployment, and will permit further insights into potential optimal offshore wind energy configurations.

The results of this study show that levelized cost of energy reductions of over 23% relative to a representative 2019 project are achievable through economies of size and scale associated with turbine and plant upsizing. This significant cost decrease is largely independent of any specific system-level technological innovation (although a myriad of small innovations and incremental advancements will be required to achieve higher turbine ratings). As such, these results provide a baseline cost reduction pathway for fixed-bottom offshore wind energy, and future work can build upon these results to evaluate the effects of specific novel technologies relative to these nominal results. Furthermore, the meaningful reduction in baseline LCOE indicates the clear advantages of larger projects comprising higher-nameplate wind turbines. This is relevant insight for policymakers, project developers, component manufacturers, and other stakeholders striving to reduce costs and to evaluate trade-offs in project development. This article suggests that the coupled impact of cost drivers associated with turbine and plant upsizing could have a transformative effect on the costs of offshore wind energy.

CRediT authorship contribution statement

Matt Shields: Conceptualization, Data curation, Formal analysis, Funding acquisition, Investigation, Methodology, Project administration, Software, Supervision, Validation, Visualization, Writing - original draft, Writing - review and editing. **Philipp Beiter:** Conceptualization, Formal analysis, Methodology, Validation, Writing - original draft, Writing - review and editing. **Jake Nunemaker:** Data curation, Formal analysis, Methodology, Software, Validation, Visualization, Writing - review and editing. **Aubryn Cooperman:** Formal analysis, Software, validation, Writing - review and editing. **Patrick Duffy:** Formal analysis, Software, Validation, Visualization, Writing - review and editing.

Declaration of competing interest

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

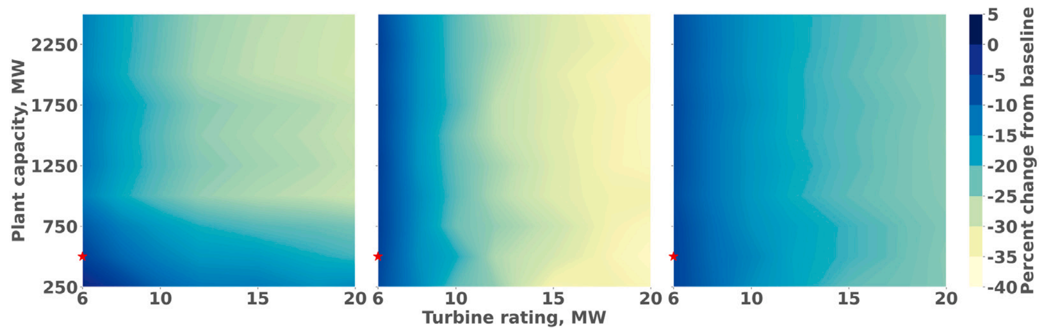

Fig. 10. Percent change from the baseline project in (from left to right) BOS costs, O&M costs, and LCOE for upsized turbine ratings and plant capacities. The red star identifies the baseline project of a 500-MW plant with 6-MW wind turbines.

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