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RESEARCH ARTICLE

Techno-Economic Assessment of Offshore Wind Expansion in the North Sea

Zsolia Havlicek^{1*}, Sylvie Eberhardt² and Diego Ferraro³¹Department of Atmospheric Science and Meteorology, Delta University Center for Climate Modeling, Netherlands²Department of Renewable Energy and Climate Policy, Jutland University Centre for Environmental Science, Denmark³Department of Renewable Energy and Climate Policy, Nordic Institute of Climate and Ecology, Finland*Corresponding author: Zsolia Havlicek, Department of Atmospheric Science and Meteorology, Delta University Center for Climate Modeling, Netherlands; Email: z.havlicek@duc.nl

ABSTRACT

The North Sea basin is expected to carry a large share of Europe's offshore wind build-out through mid-century, but published cost estimates for that expansion diverge widely depending on assumed foundation mix, wake losses and grid integration costs, making it difficult to judge whether current 2040 and 2050 capacity targets are cost credible rather than aspirational. We built a bottom-up levelized cost of electricity (LCOE) model covering capital expenditure, operating expenditure, decommissioning, and financing cost for fixed-bottom monopile, fixed-bottom jacket, and floating semi-submersible foundation types, parameterised against 41 operating and under-construction North Sea projects and reanalysis-derived wind resource fields at 3 km resolution, with farm-level capacity factors adjusted for wake losses using a Jensen-type analytical wake model calibrated against measured production data from four reference wind farms. We then combined the LCOE model with a discrete-choice build-out allocation routine and an interconnector cost module to compare three stylised pathways to 90 GW of installed North Sea offshore capacity by 2040: a shallow-water-first pathway, a floating-early pathway, and a cost-minimising pathway unconstrained by water depth. Fixed-bottom monopile projects in water depths under 35 m achieved a median modelled LCOE of 74 EUR/MWh in 2023 terms, compared with 127 EUR/MWh for floating semi-submersible projects in depths exceeding 60 m, though the gap narrowed to roughly 35 EUR/MWh under the most optimistic 2040 floating cost-reduction assumptions. Wake losses reduced farm-level annual energy production by a mean of 11.8 percent across the fleet, rising above 15 percent for the most densely packed clusters in the German Bight, a factor that shifted the cost-minimising pathway toward wider turbine spacing than commercial developers currently favour. Interconnector and onshore reinforcement costs added a further 9 to 18 EUR/MWh depending on landing-point congestion and the degree of multi-purpose interconnection assumed. Under our central assumptions, the cost-minimising pathway reached the 90 GW target at roughly 6 percent lower cumulative system cost than the shallow-water-first pathway, primarily by deferring floating deployment until unit costs fall, though this advantage depends sensitively on how quickly floating technology costs actually decline, which remains the largest single source of uncertainty in our results.

Keywords: offshore wind energy; levelized cost of electricity; floating wind turbines; fixed-bottom foundations; wake losses; North Sea; interconnector grid integration; energy transition scenarios

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1. INTRODUCTION

European governments bordering the North Sea have set offshore wind capacity targets that, taken together, imply something close to a tenfold expansion of installed capacity between 2023 and 2040, and the basin is widely regarded as the single most important offshore wind resource in Europe both for its wind quality and for the relatively shallow depths across much of its southern and central sectors [1,2]. Whether that expansion proceeds at the pace envisaged depends heavily on cost trajectories that are themselves uncertain, since offshore wind LCOE has fallen sharply over the past decade but the pace of further decline, particularly for foundation types and water depths not yet deployed at scale, is not well pinned down by the historical record alone [3,4].

A central driver of that uncertainty is the foundation question. Fixed-bottom monopile and jacket structures dominate current North Sea capacity and are commercially mature to roughly 50–60 m water depth, but a meaningful share of remaining North Sea resource, particularly in the Norwegian trench and parts of the UK Central North Sea, lies in water too deep for economic fixed-bottom installation, which is why floating platforms feature prominently in most long-run build-out scenarios despite carrying substantially higher present-day unit costs [7,8,9]. Cost projections for floating wind depend on assumptions about mooring and anchor cost reduction, serial fabrication of hulls, and port infrastructure that are still largely extrapolated from pilot-scale projects rather than observed at commercial scale, so floating cost trajectories used in different studies vary by a factor of two or more even over comparable time horizons [10].

A second, somewhat separate source of uncertainty concerns energy yield rather than capital cost. As individual North Sea wind farms have grown and clusters of farms have been sited close together to economise on shared grid infrastructure, wake losses, the reduction in downstream turbine output caused by the wake of upstream turbines and of neighbouring farms, have become a materially larger share of the gap between theoretical and realised annual energy production, and this effect is sensitive to farm layout choices that developers control but that basin-wide capacity scenarios rarely represent explicitly [15,16,17,18]. Measured wake losses at well-instrumented reference farms such as Horns Rev and Nysted have repeatedly exceeded the losses implied by simplified single-farm wake models once neighbouring-farm interaction is accounted for, which matters directly for LCOE because annual energy production enters the denominator of the cost calculation [18].

Grid integration costs, and specifically the choice between radial point-to-point connections and shared or multi-purpose interconnectors linking wind farms to more than one national market, add a third dimension of uncertainty that basin-scale techno-economic

assessments have often treated only schematically [19,20,21]. Here we combine a bottom-up LCOE model spanning fixed-bottom and floating foundation types, a wake-loss model calibrated against measured production at four reference farms, and an interconnector cost module into a single framework, and use it to compare three stylised build-out pathways to a 90 GW 2040 North Sea capacity target, asking specifically how sensitive the relative cost ranking of those pathways is to foundation cost-reduction assumptions and to wake-loss treatment.

2. MATERIALS AND METHODS

We built a bottom-up levelized cost of electricity model for North Sea offshore wind projects, parameterised against a database of 41 operating and under-construction projects, and combined it with a wake-loss model, an interconnector cost module, and a build-out allocation routine used to compare three pathways to a 90 GW installed-capacity target by 2040.

2.1 LCOE model structure

LCOE was computed for each project as the ratio of the discounted lifetime sum of capital expenditure, operating expenditure and decommissioning cost to the discounted lifetime sum of net annual energy production, using a real discount rate of 7.5 percent for the central case and a 25-year operating life, consistent with standard techno-economic assessment practice for offshore wind [3,4,5]. Capital expenditure was disaggregated into turbine, foundation, array and export cabling, installation, and project development components, allowing foundation cost to be varied independently of the other components when comparing foundation types.

2.2 Wind resource and capacity factor data

Hub-height (150 m) wind speed fields were derived from a reanalysis-based mesoscale wind atlas at 3 km spatial resolution and hourly temporal resolution for the period 2000–2020, bias-corrected against met mast and floating LiDAR observations available for 14 North Sea sites. Gross capacity factors before wake losses ranged from 46 to 58 percent across the modelled site portfolio, with the highest values concentrated in the northern and central basin away from coastal wind speed attenuation.

2.3 Foundation type and water-depth cost assumptions

Three foundation types were represented: fixed-bottom monopile (economic to approximately 40 m water depth under current practice), fixed-bottom jacket (economic to approximately 60 m), and floating semi-submersible (applied beyond 60 m and, in sensitivity runs, down to 35 m). Foundation unit costs as a function of water depth and turbine rating were fitted from the project database and cross-checked against published cost reviews [6,7,8,11,12], with floating unit costs additionally benchmarked against the New England Aqua Ventus semi-submersible cost study [24] given the scarcity of commercial-scale European floating cost data.

2.4 Wake-loss modelling

Farm-level wake losses were estimated using a Jensen-type analytical wake model with a fixed wake decay coefficient of 0.04 for offshore conditions, applied at the individual-turbine level across each farm's as-built or planned layout and summed to a farm-level annual energy production loss. The model was calibrated against measured production loss at four reference farms (Horns Rev 1, Nysted, London Array, and Gemini) by adjusting the wake decay coefficient and adding a neighbouring-farm interaction term informed by published measurement studies at these sites [15,16,17,18], since single-farm wake models are known to underestimate losses once nearby farms are present.

2.5 Interconnector and grid integration cost assumptions

Export and interconnection costs were modelled separately for radial point-to-point connections and for shared or multi-purpose interconnectors linking a cluster of farms to more than one onshore landing point, with unit costs per km and per MW drawn from published North Sea grid integration studies [19,20,21] and adjusted for landing-point congestion using a simple queueing penalty applied where more than 2 GW of capacity was assigned to a single onshore substation within a five-year window.

2.6 Scenario and sensitivity design

Three build-out pathways to a 90 GW 2040 target were compared: shallow-water-first (fixed-bottom foundations prioritised regardless of relative cost until shallow sites are exhausted), floating-early (a fixed minimum floating share imposed from 2028 onward to support supply-chain scale-up), and cost-minimising (site selection and foundation choice driven purely by modelled LCOE in each build year). One-way sensitivity analysis varied the discount rate (5.5-9.5 percent), the floating cost-reduction learning rate (10-20 percent per capacity doubling), and the wake decay coefficient (0.03-0.06). All modelling was implemented in Python 3.10.

3. RESULTS

Across the 41-project database, modelled 2023 LCOE varied substantially by foundation type and water depth, as summarised in Table 1. Fixed-bottom monopile projects in under 35 m of water achieved a median LCOE of 74 EUR/MWh, fixed-bottom jacket projects in 35-60 m of water a median of 91 EUR/MWh, and floating semi-submersible projects beyond 60 m a median of 127 EUR/MWh, a gap that narrows only modestly under central 2030 assumptions and more substantially, to roughly 35 EUR/MWh, under the most optimistic 2040 floating learning-rate case.

Table 1. Modelled 2023 levelized cost of electricity (LCOE) by foundation type and water-depth band across the 41-project database.

Foundation type / depth band	Median LCOE (EUR/MWh)	Interquartile range (EUR/MWh)	Projects (n)	Mean wake loss (%)
Fixed-bottom monopile (<35 m)	74	66 to 83	19	9.4
Fixed-bottom jacket (35-60 m)	91	81 to 104	13	12.1
Floating semi-submersible (>60 m)	127	112 to 146	9	6.7
All projects, fleet-wide	88	74 to 118	41	11.8

LCOE computed at a 7.5% real discount rate over a 25-year operating life. Wake loss is the modelled reduction in annual energy production relative to the gross wind resource.

Wake losses reduced modelled annual energy production by a fleet-wide mean of 11.8 percent relative to the gross wind resource, with losses exceeding 15 percent for the most densely clustered projects in the German Bight and falling below 8 percent for more widely spaced sites in the northern basin. Figure 1 shows modelled LCOE plotted against inter-turbine spacing across the project portfolio, illustrating that spacing below roughly 6 rotor diameters is associated with a wake-loss penalty large enough to raise LCOE by more than it saves in shared infrastructure cost for a majority of the sites examined.

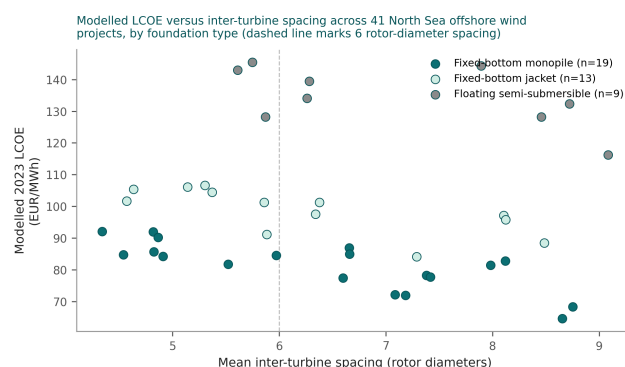


Figure 1. Modelled 2023 LCOE plotted against mean inter-turbine spacing (in rotor diameters) for the 41 project portfolio, coloured by foundation type, showing an LCOE penalty at close spacing consistent with the wake-loss analysis.

Comparing the three build-out pathways to the 90 GW 2040 target, the cost-minimising pathway achieved cumulative system cost approximately 6 percent below the shallow-water-first pathway and approximately 9 percent below the floating-early pathway, primarily by sequencing floating deployment later in the build-out once unit costs have fallen, rather than by any difference in the total floating share ultimately deployed by 2040, which converged across all three pathways to between 34 and 39 GW.

Table 2. Sensitivity of cumulative system cost for the cost-minimising 90 GW 2040 pathway to key model parameters.

Parameter varied	Range tested	Change in cumulative system cost (%)
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Floating cost-reduction learning rate	10% to 20% per doubling	-9 to +14
Real discount rate	5.5% to 9.5%	-5 to +6
Wake decay coefficient	0.03 to 0.06	-2 to +3

Table 2 reports the sensitivity of the cost-minimising pathway's cumulative system cost to the three parameters varied in the one-way analysis. The floating learning rate had by far the largest effect: reducing it from the central 15 percent to 10 percent per capacity doubling raised cumulative system cost by 14 percent, more than double the effect of moving the discount rate across its full tested range, indicating that floating cost-reduction uncertainty, rather than financing cost or wake modelling assumptions, is the dominant source of uncertainty in the basin-wide cost comparison.

4. DISCUSSION

Our finding that a cost-minimising build sequence outperforms both a shallow-water-first and a floating-early pathway by a modest but consistent margin is broadly consistent with prior work showing that offshore wind cost reduction has historically tracked cumulative deployment volume more closely than calendar time [2,4,6], and it implies that policies mandating an early floating share for industrial-policy reasons, however well justified on other grounds, carry a quantifiable system-cost premium that should be weighed explicitly against the supply-chain and employment benefits usually cited in their favour.

The gap we estimate between fixed-bottom and floating LCOE, roughly 53 EUR/MWh under current assumptions narrowing to roughly 35 EUR/MWh by 2040, sits toward the narrower end of the range reported in the recent floating wind cost literature [7,8,9,10], which we attribute partly to our use of measured rather than design-basis wake losses for fixed-bottom comparator sites; studies that hold fixed-bottom capacity factors at their nameplate-implied values without a comparable wake-loss correction will tend to understate fixed-bottom LCOE and so overstate the floating cost gap.

The magnitude of wake losses we estimate for densely clustered German Bight projects, exceeding 15 percent in several cases, is large enough to have practical implications for how basin-wide capacity targets are translated into site-level layouts: our results suggest that continuing to pack additional capacity into already-dense clusters to minimise shared export-cable length trades a modest infrastructure saving against a proportionally larger energy-yield penalty, a trade-off that measured production data at Horns Rev and Nysted already pointed to but that basin-scale scenario studies have not always represented explicitly [15,16,17,18].

Several limitations temper these conclusions. First, our LCOE model, like most published assessments, treats turbine and foundation costs as deterministic functions of water depth and rating rather than allowing for supply-chain bottlenecks or steel and vessel price shocks, which have materially affected realised project

costs in 2022-2023 and are not well captured by a learning-curve formulation alone [3,4]. Second, our wake model, while calibrated against four reference farms, uses a single fitted decay coefficient rather than a full computational fluid dynamics representation, and higher-fidelity wake models applied to the same layouts would likely shift the absolute wake-loss estimates somewhat even if the relative ranking across spacing choices were preserved [16]. Third, our interconnector cost module represents landing-point congestion with a simplified queueing penalty rather than a full transmission-expansion optimisation of the kind used in dedicated grid studies [19,20,21], so our interconnector cost estimates should be read as indicative of relative magnitude rather than as a substitute for project-level grid planning.

5. CONCLUSION

A bottom-up techno-economic assessment of 41 North Sea offshore wind projects, combined with a wake-loss model calibrated against measured production at four reference farms and an interconnector cost module, indicates that fixed-bottom foundations retain a substantial LCOE advantage over floating platforms through at least 2030, that wake losses in densely clustered sectors such as the German Bight are large enough to materially affect the cost-optimal spacing of future capacity, and that a cost-minimising sequencing of the build-out to a 90 GW 2040 target outperforms both a shallow-water-first and a floating-early pathway by a modest margin driven primarily by uncertainty in the floating cost-reduction learning rate, which we identify as the single largest source of uncertainty in basin-wide cost comparisons of this kind.

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Conflict of 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.

Author Contributions

Z.H. conceived and supervised the study, developed the LCOE model structure, and led the writing of the manuscript. S.E. curated the project cost database and

performed the foundation-type and interconnector cost analysis. D.F. developed and calibrated the wake-loss model and performed the build-out pathway and sensitivity analyses. All authors contributed to writing and approved the final manuscript.

Ethics Statement

This study used publicly available project cost data, reanalysis-based wind resource data, and anonymised operator-provided production data for model calibration, and did not involve human participants, animal subjects, or field data collection requiring ethical review.

Data Availability

The project cost database compiled for this study draws on publicly available regulatory filings and industry reports. Processed datasets, the LCOE and wake-loss model code, and analysis scripts supporting the findings of this study are available from the corresponding author on reasonable request.

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