MARINEWIND

Market Uptake Measures of Floating Offshore Wind Technology Systems (FOWTs)

1/11/2022 – 31/10/2025

Call: HORIZON-CL5-2021-D3-02

Project 101075572 — MARINEWIND

D3.5 Final financial and techno-economic analysis

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Section 1 - Final financial analysis

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EXECUTIVE SUMMARY

This deliverable presents the final financial and techno-economic analysis for floating offshore wind technology (FOWT) pilots examined within MARINEWIND. It consolidates a consistent, scenario-based Levelised Cost of Energy (LCOE) framework, a transparent data architecture, and country-specific applications for representative sites in the UK, Italy, Portugal, and Spain. The central contribution is a reproducible Monte-Carlo cash-flow workflow that integrates macro-financial dynamics (inflation, debt costs, taxation, and capital structure) with site-specific energy yield generated from Weibull wind-resource parameters and a reference turbine power curve. The outputs are decision-grade distributions for lifetime LCOE, Weighted Average Cost of Capital (WACC), Return on Equity (ROE), and capacity factor (CF), complemented by a simplified fixed-charge LCOE benchmark for comparison.

The methodology starts from two data layers: (i) asset-specific inputs—capacity, lifetime, CAPEX/MW, OPEX/MW-yr, and engineering losses—and (ii) environment inputs—country macro variables and Weibull parameters (shape/scale) at hub height. These feed a two-tier simulation: annual macro variables and OPEX are drawn from bounded distributions, while energy is computed each year from simulated Weibull realizations mapped through the IEA-15-240-RWT power curve with ageing and park-loss adjustments. The annual cash-flow loop discounts costs and energy using the path-specific WACC to produce lifetime indicators per scenario, from which medians and confidence bands are reported.

Applied to pilots, the framework shows tightly concentrated LCOE outcomes where financing conditions moderate the effect of CF ageing on lifetime unit costs. For example, in the Kincardine case (UK), the model LCOE centers near £195/MWh with WACC around 8.6% and median ROE ~13%, while in the planned 1 GW cases for Italy, Portugal, and Spain, central LCOE values lie in the €145–€187/MWh range with WACC medians between ~6.4% and ~10.3%, reflecting differences in macro settings, scale, and resource. Across sites, the dynamic model often diverges from the simplified metric, highlighting the value of path-wise discounting and endogenous leverage/interest evolution.

The tool's interface and data-entry design lower barriers for peer review and sensitivity analysis: all macro, cost, and wind parameters are captured on a single screen, with "fix" toggles to switch drivers between deterministic and stochastic modes. This streamlines early-stage studies while maintaining traceability for audit and replication. In sum, the deliverable provides (i) a coherent, documented simulation methodology; (ii) country applications with interpretable outputs; and (iii) a practical web implementation that links macro-finance and wind-resource variability in one consistent workflow.

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1. Introduction

1.1 Purpose of this document

Floating offshore wind is entering a scale-up phase in Europe. Investment decisions must therefore reconcile engineering performance with financing conditions that evolve through construction and operations. A single-point LCOE is inadequate for this purpose; it masks dispersion in both energy and costs and cannot represent the time profile of financing risk. The purpose of this deliverable is to provide a robust, scenario-based framework for LCOE evaluation and a standardised way to present WACC, ROE, and CF trajectories that are consistent across countries and sites. The work emphasises reproducibility, data parsimony, and auditability, enabling project teams to update inputs as new information arrives while preserving a common analytical backbone.

2.2 Analytical approach

Data model. Inputs are organised in two groups. Primary, project-specific data include plant size, lifetime, CAPEX/MW, OPEX/MW-yr, equity share, and loss/ageing parameters. Secondary, environment data include inflation, debt interest, corporate tax rate, and feed-in tariff; and wind-resource parameters (Weibull shape and scale at hub height). This structure allows a uniform treatment across pilots while keeping space for site-specific calibration.

Energy model. Annual energy is generated from Weibull draws using site-specific shape/scale pairs. These are mapped through the IEA-15-240-RWT power curve and adjusted for ageing (annual derating) and park-level losses (wake, electrical, availability). The result is a time-series of net MWh and CF for each scenario path. Because energy is computed rather than assumed, the model preserves physical interpretability and allows sensitivity to resource uncertainty.

Financial model. The discounted-cash-flow loop is evaluated annually. Revenues equal tariff × net MWh; operating costs are OPEX realizations scaled by capacity; financing costs derive from the evolving leverage and debt coupon. WACC is computed path-by-path using the after-tax cost of debt and contemporaneous equity return and is applied to discount both costs and energy to present values. Lifetime LCOE per path equals the ratio of discounted costs to discounted energy. The procedure produces full distributions (median, bounds) for LCOE, WACC, ROE, and CF.

Benchmarking. A simplified, fixed-charge LCOE (after NREL's ATB conventions) is calculated for reference, enabling comparison with the dynamic results. Differences between the two highlight the implications of path-dependent discounting, changing financing mix, and CF ageing.

2.3 Implementation

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The analysis is delivered through a browser-based interface (MARINEWIND LCOE Tool) that consolidates all inputs on one page with clearly labelled units and currency handling. A "fix" toggle per variable enables quick scenario design (e.g., hold inflation fixed to isolate wind-resource dispersion). The tool returns summary statistics and annual confidence envelopes and supports export for offline diagnostics. This design reduces transcription errors, accelerates peer review, and makes the workflow accessible to non-specialist users while retaining transparency for expert audit.

2.4 Country applications

Four pilots illustrate the method's portability:

- **UK (Kincardine, reference case):** LCOE concentrates near £195/MWh; WACC tends to decline through operations as leverage and coupons evolve; ROE is strongest in early years and converges as CF erodes with ageing.
- **Italy (planned Sicily site):** A 1 GW scale and 20-year life produce a concentrated LCOE around €187/MWh; WACC median is ~6.4%, and ROE medians are modest with sensitivity to downside combinations.
- **Portugal (Atlantic, planned 1 GW):** LCOE clusters just below €150/MWh; WACC centers near ~10.3%; ROE is attractive on average but benefits from OPEX discipline and timely financing optimization.
- **Spain (Mediterranean, planned 1 GW):** LCOE centers just under €145/MWh with WACC ~7.4% and serviceable ROE; differences relative to Portugal reflect macro-financing assumptions and resource/loss profiles.

These cases demonstrate that combining site-specific Weibull energy modelling with macro-finance uncertainty yields stable, interpretable distributions whose centers and spreads vary with tariff design, leverage, OPEX envelope, and wind regime.

2. Evaluation Methodology of Levelized cost of energy

The MARINEWIND probabilistic cash-flow model returns five key indicators for every floating-offshore-wind pilot: General Levelised Cost of Energy (LCOE), the National Renewable Energy Laboratory (NREL) simplified LCOE, Weighted-Average Cost of Capital (WACC), Return on Equity (ROE) and Capacity Factor (CF). Producing these metrics requires a carefully organised set of input variables.

2.1 Data collection

In this section we describe the input data required to perform the comprehensive LCOE analysis for each MARINEWIND lab. The data required is grouped into two datasets i) primary data about the specific Floating Offshore Wind Farm (FOWF) such as Farm capacity, Equity ratio, CAPEX components, OPEX and expected life time of the plant; and ii) secondary data about the macroeconomic variables (Interest rate on debt, inflation rate, corporate tax rate and Feed in tariff) and Capacity factor (Weibul distribution parameters Scale and Shape, wind speed, turbine power curve, and wind turbine losses due to degradation).

Macroeconomic variables:

- **Inflation rate.** Monthly consumer-price indices are downloaded from the London Stock Exchange Group (LSEG) Data & Analytics platform, which republishes Eurostat series in a harmonised format. After alignment to a common base year the index is converted to annual growth rates.
- **Nominal interest rate.** Policy and interbank reference rates are taken from the same LSEG database. Used to measure the cost of debt, and weighted average cost of capital.
- **Corporate income-tax rate.** Statutory rates are collected from official government websites. The tax parameter adjusts both after-tax cash flows and the debt-interest tax shield that appears in the WACC calculation.
- **Feed in Tariff (FiT).** Is the guaranteed purchase price per megawatt-hour (Mwh) for the electricity to be generated by the FOWT plant. The FiT feeds into the measurement of the Return On Equity (ROE).
- **Capital-structure share.** The share of CAPEX raised through debt to equity. Within the simulations it is allowed to vary slightly, reflecting the bandwidth observed in recent European offshore-wind financings. This share feeds directly into WACC and ROE.

Capacity-factor variables

The annual **Capacity Factor (CF)** expresses how efficiently a floating-offshore wind farm converts its installed capacity into electrical energy. To compute CF within the MARINEWIND financial model, the simulation engine draws on a concise but interconnected set of input variables. These variables originate either from public environmental databases for meteorology or from the engineering documentation for FOWT. The list below describes each variable, explains where it is obtained and clarifies the specific stage of the CF calculation, probability distribution, turbine power curve, or park-level adjustment in which it is used.

- The **shape factor (*k*)** defines how sharply wind speeds are clustered about the mean at a given site. Lower values denote a broad spread of calm and gusty hours, whereas higher values imply steadier winds. In the MARINEWIND model, *k* enters the probability distribution that governs hourly wind speeds; by doing so, it influences every subsequent step that converts wind to energy. Ten-year series of *k* are derived from hourly hub-height data downloaded from the **New European Wind Atlas (NEWA)**; if a pilot lacks the full record, an interim default is taken from the long-term mean of the closest offshore grid cell in the same national zone.

- The **scale factor (λ)** provides the second Weibull parameter required to anchor the distribution to the absolute wind-speed range observed at the site. While *k* controls the distribution's shape, *λ* fixes its horizontal stretch and therefore determines the expected frequency with which winds exceed the turbine's cut-in speed. Like *k*, *λ* is calculated from the same ten-year NEWA record and is stored solely for driving the statistical representation of the wind climate.
- The **average hub-height wind speed ($\bar{v}$)** offers a concise measure of the wind resource and acts as an independent check on the plausibility of the fitted Weibull parameters. MARINEWIND reads $\bar{v}$ directly from the interactive layers of the NEWA web map and stores it alongside *k* for each pilot site. Although $\bar{v}$ is not itself used in the probability draws, it helps validate that the chosen *k* and scale values reflect the observed wind climate.
- The **aging factor** represents the gradual reduction in aerodynamic and electrical efficiency that offshore turbines experience in service. Within the model this factor scales the manufacturer's power curve downward year after year, thereby lowering projected energy output and, by extension, capacity factor. The default rate is taken from multi-year performance studies that reported an annual decline of roughly two-thirds of one percent; those empirical findings are summarised in the MARINEWIND capacity-factor technical note.
- **Wind-farm losses** aggregate the effects of wake interactions between turbines, electrical conversion losses and scheduled maintenance down-time. After single-turbine production is summed across the array, the loss percentage converts gross megawatt-hours to net export at the grid connection. Each pilot team supplies its own loss allowance through the common engineering template; an illustrative figure of ten percent is shown in the capacity-factor calculation document.
- The **number of turbines** fixes the physical scale of the plant. It multiplies single-turbine generation to yield farm-wide output before that total is normalised by installed capacity to produce the capacity-factor series. Turbine counts come from the approved site layout included in the same engineering template that lists park losses; for example, the reference case in the documentation assumes sixty-seven machines.

Together, these five variables—*k*, $\bar{v}$, the aging factor, wind-farm losses and number of turbines form the essential data set for estimating annual capacity factors in MARINEWIND's financial analysis.

FOWT specific input data

The data specific to the FOWT is grouped into two parts, CAPEX components and OPEX. The CAPEX consists of the following cost inputs:

- **Development and consenting cost:** This entry covers site studies, environmental impact assessments, legal fees and all regulatory application charges required before construction may begin. The cash-outflow appears early in the schedule and therefore strongly influences the model's financing drawdown. Values are taken from partner project-management budgets and verified against third-party permitting consultants' quotations.

- **Turbine cost:** The procurement price of nacelles, blades, towers and spares is recorded under this line. It drives the largest single slice of upfront investment and sets the baseline for depreciation in the cost ledger. Prices are imported from turbine-supply agreements or, where contracts are not yet signed, from vendor term sheets collated by the engineering leads.
- **Platform cost:** Platform cost refers to the fabrication of steel or concrete floating substructures sized for the reference 15 MW turbine class. The figure feeds into construction-phase cash flows and is needed to calculate interest during construction. Estimates come from competitive tenders received by the marine-structures work package.
- **Anchoring and mooring cost:** This variable covers drag-embedment anchors, chain or synthetic lines, load shackles and associated installation consumables. Because mooring layout varies by bathymetry, the cost serves as a key sensitivity input for deep-water pilots. Data is supplied in the mooring-engineering template completed by each site partner.
- **Installation cost:** All vessel spreads, port fees, heavy-lift day rates and offshore commissioning services are aggregated here. Installation expenditure establishes the final milestone for capitalisation of interest and thus affects total financing cost. The numbers originate from logistics schedules prepared by the balance-of-plant contractor.
- **Intra-array cables cost:** Procurement and lay of inter-turbine medium-voltage cables appear under this heading. The cost influences both CAPEX and subsequent electrical-loss assumptions. Lengths and unit rates are provided by the electrical-systems package based on cable-routing studies.
- **Export cable cost:** This item records high-voltage export cable supply, seabed trenching and landfall works up to the grid substation. It is required to capture grid-connection CAPEX and any associated contingency funds. Figures come from grid-connection budgets and are cross-checked against transmission-system-operator benchmarks.

While the OPEX is the summation of the following variables[1]:

- **Fixed operations cost:** Fixed operations cover control-room staffing, marine coordination, insurance premiums and other costs that do not scale with output. They establish a baseline annual charge applied from the first full year of service. Data are pulled from operator business-plan spreadsheets submitted during the partner survey.
- **Fixed maintenance costs:** These are scheduled preventive tasks—annual inspections, gearbox oil exchange campaigns and statutory certification fees—that occur regardless of turbine availability. The costs influence long-term cash-flow stability and are gathered from original-equipment-manufacturer maintenance manuals and service-contract drafts.

[1] https://guidetoanoffshorewindfarm.com/wind-farm-costs/

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- **Variable operations and maintenance costs:** Unplanned corrective works—component replacements, vessel call-outs and unscheduled crane hire—are entered here. The item introduces stochastic spread to lifetime OPEX, as failure rates vary with turbine ageing. Baselines are taken from historical failure statistics provided by the operations partner and checked against offshore-wind reliability databases.

2.2 Levelised Cost of Energy (LCOE) - General model

The **Levelized Cost of Energy (LCOE)** is a metric that measures the average cost per unit of electricity generated over a project's lifetime. In essence, it is defined as the **ratio of the total discounted costs** of a power plant to the **total discounted energy output** over its lifetime. All relevant life-cycle costs are included from upfront **capital expenditures (CAPEX)** (e.g. development and construction) to ongoing **operating expenditures (OPEX)** (operations and maintenance). Both the costs and the electricity generation are expressed in net present value (NPV) terms by discounting future cash flows and outputs to today's value. This ensures that later-year costs or generation (which are less valuable due to the time value of money) are appropriately weighted in the calculation. The result is typically given in currency per energy unit (e.g. £/MWh or EUR/MWh), allowing a comparison of different generation technologies on a "cradle-to-grave" cost basis. The LCOE formula is given by:

$$LCOE = \frac{CAPEX_0 + \sum_{t=1}^{n} \frac{OPEX_t}{(1+WACC_t)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+WACC_t)^t}}$$

Where CAPEX is the capital expenditure, OPEX is the annual operating and maintenance costs of the plant during its operational years, E is the energy production of the FOWT and WACC is the weighted average cost of capital, a proxy for the discount rate.

However, note that when LCOE is used without taking into account future uncertainties such as changes in OPEX, Inflation rate, interest rates and wind turbine energy production degradation it becomes misleading (H. Amlashi and C. Baniotopoulos (2024)). For floating offshore wind farms, many key inputs (from capital cost to energy yield) are uncertain and can vary significantly over a project's lifecycle. To address this, we have developed probabilistic or stochastic LCOE methodologies that treat input parameters as random variables rather than fixed values. The general approach is to perform a **Monte Carlo simulation**:

- Instead of a single OPEX value, a probability distribution is assigned to reflect its uncertainty. For example, we might assume a ± 20% variability in OPEX around a mean estimate. Each simulation run draws a random value from these distributions.
- Likewise, **annual energy production** can be treated probabilistically. Wind speed variation is commonly modelled with a **Weibull distribution**, combined with turbine power curves to derive a distribution for the capacity factor or annual output. This accounts for inter-annual variability in wind resource, turbine performance, and array losses.

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- The model then calculates an LCOE for each simulation run (using the same formula as above but with that run's sampled inputs). After a thousand runs, we obtain 1000 paths for LCOE outcomes rather than a single value. This distribution is then summarized with statistics (median, 95% confidence interval bounds) to indicate the range of possible LCOE values and their likelihood.

Moreover, treating inputs as random variables allows analysts to identify which uncertainties drive the LCOE the most (via **sensitivity analysis**). Some key uncertain parameters in floating offshore wind LCOE analyses include:

- **Operational Expenditure (OPEX):** Yearly O&M and operational costs can fluctuate (e.g. unexpected maintenance, vessel costs, insurance). Because OPEX recurs every year, its uncertainty can compound. Studies have found that **variation in OPEX can significantly influence LCOE** in fact, one probabilistic analysis showed the LCOE distribution was more sensitive to OPEX assumptions than to CAPEX or decommissioning costs. This is intuitive, as higher-than-expected ongoing costs each year will directly increase the average cost per MWh.
- **Capacity Factor:** This is often the **single largest driver of LCOE uncertainty** for wind. The capacity factor depends on wind resource quality, turbine performance, and array effects. If actual winds are lower than predicted (or turbine downtime higher), the energy output drops, driving LCOE up (since costs are then spread over fewer MWh). **Probabilistic LCOE models treat capacity factor or annual energy as a distribution** – e.g. using wind speed probability distributions or a range of possible loss factors. A small absolute change in capacity factor (say 5% lower) has a direct proportional increase in LCOE, making this a critical uncertainty to capture.
- **Discount Rate:** The discount rate (often related to the project's financing or Weighted Average Cost of Capital) has a strong effect on LCOE because it alters the present value of future costs and generation. Higher discount rates give less weight to long-term outputs, effectively raising LCOE for capital-intensive projects. Different organizations use different discount rates for offshore wind, reflecting varying risk and financing assumptions. In a sensitivity analysis, applying a higher discount rate will increase LCOE, while a lower (or subsidized) rate lowers it, all else equal. Therefore, scenarios examining variation in the discount rate are important. Some researchers have even proposed alternative risk-adjusted discounting or **certainty-equivalent** methods to better account for project risk in LCOE calculations (Soojin et al. (2021), underscoring that how we handle the discount rate can noticeably change the outcome. In our analysis we proxy the discount rate using an annual WACC.

In practice, a **probabilistic LCOE evaluation** for a floating wind farm would proceed by assigning each of the above factors a reasonable range or distribution (based on empirical data or expert judgment), then running simulations. The outcome is often presented as a probability density or cumulative probability curve of LCOE. This provides valuable information to decision-makers: for example, the probability that LCOE will fall below a certain target, or the **confidence interval** for the expected LCOE. It also enables **tornado charts** or other sensitivity outputs to rank which uncertainties contribute most

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to LCOE variance. In summary, while the traditional (deterministic) LCOE formula gives a single-point estimate useful for baseline comparison, **incorporating stochastic methods and uncertainty analysis yields a more robust evaluation methodology** for floating offshore wind farms. This comprehensive approach aligns with recent academic recommendations to support better risk-informed investment decisions and policy planning in the offshore wind sector.

2.2.1 Weighted Average Cost of Capital (WACC)

The **Weighted Average Cost of Capital (WACC)** represents the average rate of return that a project must pay to its capital providers (debt and equity holders). It is a foundational input in project finance modelling, determining how future cash flows are discounted and thus influencing metrics like the levelized cost of energy (LCOE) and investor returns. In the context of floating offshore wind farms, which are capital-intensive and relatively new, accurately evaluating WACC is crucial. The U.S. National Renewable Energy Laboratory (NREL) provides widely respected guidance on WACC through its Annual Technology Baseline (ATB) and financing publications. These resources outline how to compute WACC and integrate it into renewable energy financial models. According to NREL's ATB, WACC is used as the discount rate in LCOE calculations, feeding into the capital recovery factor that annualizes capital costs. This section develops a detailed WACC evaluation methodology for floating offshore wind, explaining how WACC is computed, how it factors into LCOE and return on equity (ROE) calculations, and how debt and equity costs under a given capital structure are accounted for. We also discuss the limitations of using a static WACC in offshore wind models and explore methods to incorporate dynamic or annual WACC in probabilistic analyses. In financial terms, WACC is the blended cost of a project's financing, weighted by the proportion of debt and equity in the capital structure. The WACC is calculated as:

$$WACC_t = \frac{1 + [(1-DF) * \{(1 + ROE_t) * (1+\pi_t) - 1\}] + [DF * \{(1+r_t) * (1+\pi_t) - 1\} * (1-TR)]}{1+\pi_t} - 1$$

$$r_t = \frac{1+i_t}{1+\pi_t} - 1$$

Where:

- *i = nominal interest rate,*
- π = inflation rate,
- DF = debt factor,
- ROE = Return on Equity,
- r = real interest rate
- R = corporate tax rate

While WACC represents the discount rate, the return on equity (ROE) is a component of WACC that represents the equity investors target internal rate of return. Equity investors typically target a certain IRR (internal rate of return) on their invested capital, which we refer to as the cost of equity in the

WACC. In a project finance model, analysts often solve for the feed-in tariff that yields a target ROE for equity investors, given assumptions about debt terms. The ROE feeds into the WACC. It's important to clarify that WACC is not the same as ROE, but a composite. For a highly leveraged project, the WACC will be much lower than the equity's required return, because cheaper debt capital dominates the mix. Conversely, for a project financed mostly with equity, WACC approaches the equity return. For floating offshore wind projects, which might initially involve somewhat higher risk, equity investors could demand higher returns, but if substantial debt financing is available at moderate interest, the WACC could still remain in single digits. Financial models ensure consistency between WACC and ROE by linking them through capital structure.

Fixed WACC vs time-varying WACC:

A single, unchanging WACC is straightforward to apply in LCOE applications, yet it obscures fundamental realities that shape financing costs for floating-offshore wind. First, the risk profile of a project does not stay fixed. Capital is most expensive during construction, when technology and schedule uncertainties dominate; once turbines have been commissioned and power is flowing under a long-term contract, the same project can refinance on markedly better terms. Treating WACC as constant therefore overstates the cost of capital in later, de-risked operating years and understates it in the risk-laden build phase. Second, WACC moves with the macro-economy and is affected by Interest-rate cycles, inflation surprises, tax rates and ROE. Therefore, a static WACC cannot capture these dynamics. Also, a fixed discount rate is deterministic. It provides no way to express uncertainty in future operating costs, leaving analysts blind to how much levelized-energy cost (LCOE) might rise or decrease in the future. A more realistic modelling lets WACC vary. One option is a time-varying approach which apply a stochastic treatment representing the cost of debt, target return on equity and debt fraction as probability distributions and sample them in a Monte Carlo simulation, producing a distribution of WACC values and, by extension, a distribution of LCOE. Advanced studies may go further by linking these WACC draws to other variables such as higher inflation can raise nominal WACC yet also index tariff revenues so that each simulated future remains internally consistent. Any of these methods adds limited complexity but yields a far richer and more credible picture of financing risk for floating-offshore wind than a single, static discount rate.

2.2.2 Return on Equity

Return on Equity (ROE) measures the annual return that project shareholders earn on the capital they have invested. In the MARINEWIND financial model it is expressed as

$$ROE = \frac{Net\ income}{shareholder\ equity} * (1 - Tax\ rate)$$

$$Net\ income = Feed\ in\ tariff * Capacity\ factor * Hr - (CAPEX + \sum_{t=1}^{Life\ of\ plant} \frac{OPEX_t}{(1+WACC_t)^t})$$

$$Shareholder\ equity = Initial\ investment\ by\ owners\ = CAPEX\ *\ Equity\ fraction$$

Where Hr = number of hours per year, Capacity factor refers to the actual energy produced by a power plant over a specific period to the maximum possible output if the plant, CAPEX is the Capital expenditure, OPEX is the operating and maintenance expenditure during the operation years of the FOWT plant and WACC is the discount rate.

2.2.3 Capacity Factor

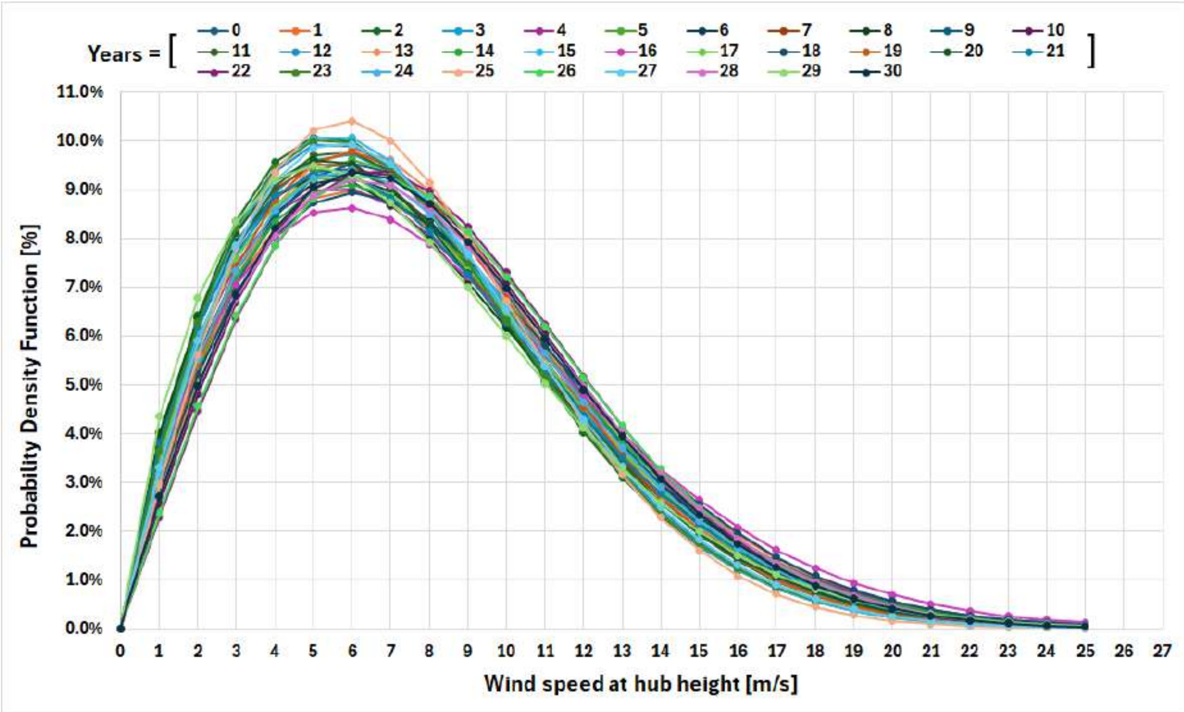
Annual wind power production

The capacity-factor workflow begins by describing the site wind climate with a Weibull probability-density function. The **shape parameter, *k*,** controls how sharply the annual wind-speed distribution peaks: larger values yield a narrower range of speeds and therefore a steadier resource. For each pilot, *k* is calculated year-by-year from ten years of hourly hub-height data downloaded from the **New European Wind Atlas (NEWA)**. Where a full decade of measurements is still being compiled, an interim default is assigned from the ten-year mean at an offshore grid cell that best matches the licence area; typical defaults span roughly 1.9 in the Sicily Strait to about 2.3 in the central North Sea and are replaced as soon as site-specific records become available. The **scale parameter, *C*,** is estimated alongside *k* from the same NEWA data set and anchors the distribution to the observed speed range, thereby dictating the absolute level of expected energy capture. A third meteorological input, the **average hub-height wind speed, $\bar{v}$,** is read directly from the interactive NEWA map. Although it plays no direct role in the Monte-Carlo draws, $\bar{v}$ provides an important cross-check on the plausibility of the fitted Weibull parameters and offers a fallback estimate of energy yield should the parameter fit prove unstable. Note that due to the complexity of modeling year-to-year variability in these parameters, the Box-Muller transformation [G. E. P. Box and Mervin E. Muller, *A Note on the Generation of Random Normal Deviates*, The Annals of Mathematical Statistics (1958), Vol. 29, No. 2, pp. 610–611] was used to generate a multi-year synthetic dataset of Weibull parameters. This method allows for the generation of pairs of normally distributed, independent random numbers with zero mean and unit variance. Each parameter was assumed to follow a normal distribution centered around its 10-year mean, with variability limited to within two standard deviations. Using the random sequences obtained through the Box-Muller method, multiple Weibull distributions were generated to represent interannual variations in wind resource at the site $(PDF_y(v))$ calculated by the following:

$$PDF_y(v) = \frac{\kappa_y}{\lambda_y}\left(\frac{v}{\lambda_y}\right)^{\kappa_y - 1} e^{-\left(\frac{v}{\lambda_y}\right)^{\kappa_y}}$$

Turbine power-curve parameters

Wind climate alone does not determine electrical output; the turbine's aerodynamic response is encoded through five design variables. The **rotor diameter** sets the swept area that captures kinetic energy, while the **hub height** guarantees that the wind-speed data and the manufacturer's power curve refer to the same elevation. Three threshold speeds—**cut-in, rated (nominal) and cut-out**—define the operating envelope; wind below the cut-in or above the cut-out produces no power, and between those limits the curve rises to its rated plateau. The **generator-system efficiency** then converts aerodynamic power into electrical output through a uniform scalar adjustment. Long-term performance decay is represented by an **ageing factor** that reduces the entire power curve by a fixed proportion each year, reflecting empirical evidence from operational offshore fleets. Together, these variables map every hourly wind speed generated by the Weibull model to an instantaneous electrical power value. The shape and scale parameters are given by:



For each synthetic year, wind distributions were used to simulate the expected power production from a turbine at hub height. The turbine model selected for this study was the IEA-15-240-RWT (https://github.com/IEAWindSystems/IEA-15-240-RWT), which defines the expected power output as a function of wind speed at hub height. The power curve of the turbine was implemented following the methodology described in [RDS Lanni 2023], based on the following equation:

$$P_y(v) \ = \frac{1}{2} * \rho * A \ * \eta_y \ * C_p(v) * v^3$$

Where is the air density at hub height, A is the rotor swept area, y is the yearly overall efficiency of the turbine, CP(V) is the power coefficient at wind speed v, and v is the wind speed at hub height. In our

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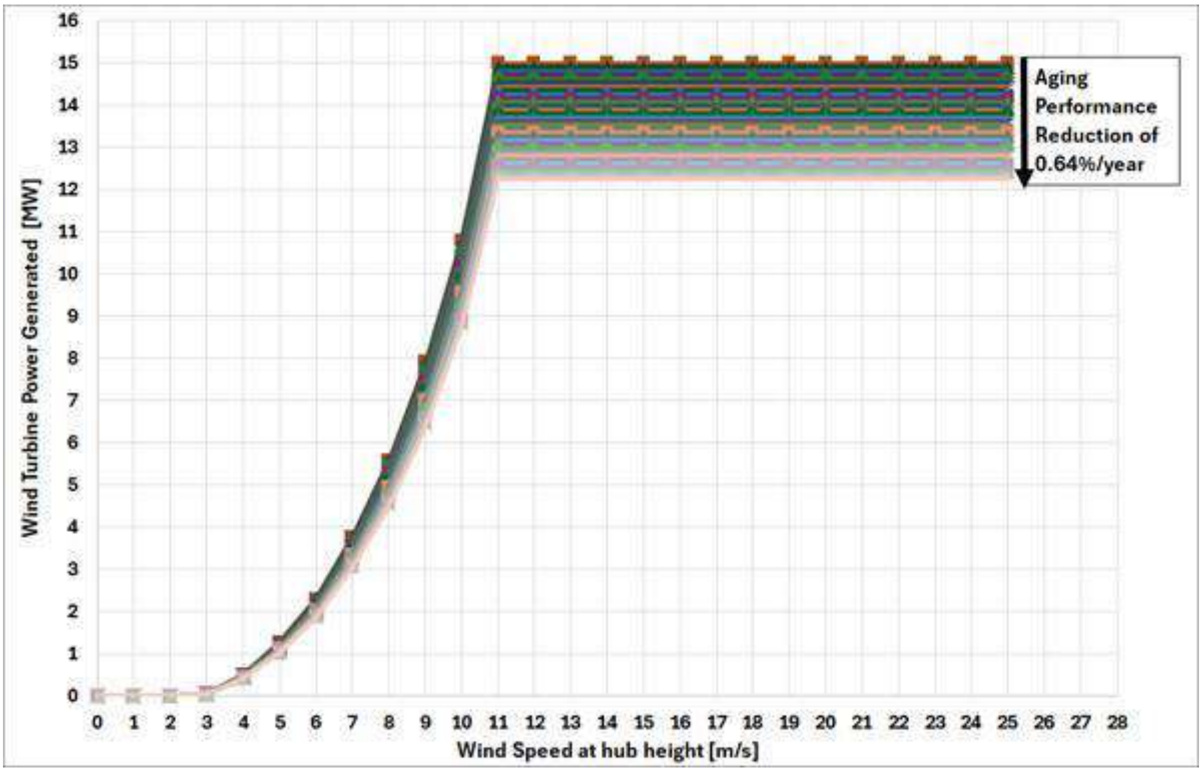
analysis the input data used for the turbine model are the same as those provided by the IEA task that developed the IEA-15-240-RWT reference turbine. These data are publicly available on GitHub. The specific values adopted for this analysis are summarized in the table below:

Parameter	Value	Unit
Turbine Size	15	MW
Rotor diameter	242.2377565	m
Cut-in Wind Speed	3	m/s
Nominal Wind Speed	10.86770694	m/s
Cut-out Wind Speed	25	m/s
Hub Height	150	m
Generator Rated efficiency	0.958979992	%

Plant-level configuration parameters

To estimate the LCOE of an offshore wind farm, we define the size of the plant in terms of the number of turbines it comprises. Accordingly, the expected energy production must be calculated, accounting for realistic system losses typically expressed as a percentage of gross production. Additionally, to account for the degradation in turbine performance over time—an effect documented in multiple studies—an aging factor was introduced in the computational tool. This factor directly affects the turbine's power curve efficiency, which nominally is around 0.959 as reported in Table 2. According to Mathew et al. (2022) in *"Estimation of Wind Turbine Performance Degradation with Deep Neural Networks"*, a degradation rate of approximately **0.64% per year** was observed in Norway, consistent with trends identified in the UK and US. Assuming a 30-year operational lifetime for an offshore turbine, the resulting reduction in the power curve was implemented in the model as shown in the figure below.



To compute the **annual Capacity Factor (CF)** for each year, the generated power (derived from the power curve) was multiplied by the expected occurrences of each wind speed value as described by the annual Weibull distributions. The CF for year *y* is computed using the following integral:

$$CF_y = \frac{\int_0^{\infty} P_y(v)\, PDF(v)\, dv}{P_{y=0}(v_{nom})}$$

Where $P_y(v)$ is the turbine power output at wind speed *v*, adjusted for year *y* including degradation, $P_y(v)$ is the Weibull probability density function for year *y*, v_{nom} is the rated wind speed, and $P_{y=0}(v_{nom})$ is the rated power output at nominal conditions. This integral was solved numerically using the trapezoidal method, requiring the definition of a sufficiently small wind speed step Δv. In this implementation, a step size of 0.01 m/s was found to provide good convergence without incurring excessive computational cost. A 20-year simulation was then conducted using the described input parameters.

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2.3 Simplified Levelised Cost of Energy (LCOE) - NREL

The **simplified LCOE** published by NREL is designed for preliminary screening of renewable-energy projects. Instead of tracing every annual cash flow, it represents the entire life-cycle economics through a single equation centred on a **fixed-charge rate (FCR)**. The FCR is a composite multiplier that already reflects financing costs (WACC), corporate taxation, depreciation allowances and the loan-repayment schedule. Once the FCR has been set, only four additional inputs are required:

$$LCOE_{NREL} = \frac{(FCR * [CAPEX + OPEX]}{Annual\ Energy\ Production}$$

Because the FCR multiplies the lump-sum CAPEX and OPEX, the equation converts all up-front expenditure into a uniform annual charge, then spreads that charge—together with annual operating costs—over expected annual output. No year-by-year discounting is required, which makes the method attractive for preliminary feasibility work or for technology benchmarking where detailed financial schedules are unavailable.

Deriving Simplified LCOE from the general LCOE:

As demonstrated in Appendix 1 (Eq. A1), the simplified levelized cost of energy (LCOE) formula proposed by NREL produces results that are virtually identical to those obtained with the full LCOE expression when certain assumptions are met such as i) the annual energy production E and the costs are considered constant over the years of the FOWT operation and ii) **t**he CAPEX is paid fully at year t=0 during the construction phase. When these assumptions are met the Full general LCOE becomes:

$$LCOE \cong sLCOE = \frac{CAPEX_0 * CRF + OPEX}{8760 * CF}$$

Fixed Charge Rate (FCR)**:** amount of revenue per Euro of investment required that must be collected annually from customers to pay the carrying charges on the investment. The FCR is given by:

$$FCR = CRF + Project\ Finance\ Factor$$

$$CRF = \frac{WACC(1 + WACC)^n}{(1 + WACC)^n - 1}$$

$$WACC = \frac{1 + [(1 - DF) * \{(1 + ROE) * (1 + \pi) - 1\}] + [DF * \{(1 + r) * (1 + \pi) - 1\} * (1 - TR)]}{1 + \pi} - 1$$

$$r = \frac{1 + i}{1 + \pi} - 1$$

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Where i is nominal interest rate, π is the inflation rate.

Project Finance Factor (PFF): is the technology-specific financial multiplier to account for any applicable differences in depreciation schedule, and tax policies. *PFF* is given by:

$$PFF = \frac{(1 - TR) * PVD}{1 - TR}$$

Present Value of Depreciation (PVD): is a function of depreciation factor (the fraction of capital depreciated each year). PVD is given by:

$$PVD = Depreciation\ factor * discount\ factor$$

$$discount\ factor = exp^{(-r*(years))}$$

Capital Expenditures (CAPEX): Capital expenditures required to achieve commercial operation of the generation plant. CAPEX is given by:

$$CAPEX = CFF * (OCC + GCC)$$

Construction Finance Factor (CFF): is the portion of all in capital cost associated with the construction period financing of the project. CFF is given by:

$$CFF = \sum_{t=0}^{t=n-1} \quad [Capital\ Fraction_t * \{1 + ((1+\pi)^t - 1\}]$$

Grid Connection Cost (GCC): are the carried costs to connect the supply point with the electricity grid of the distribution station. GCC is given by:

$$GCC = OnSpur\ cost + OffSpur\ cost$$

2.4 LCOE Tool

The MARINEWIND LCOE Simulation Tool is a browser-based application that estimates the cost of electricity from floating-offshore wind farms by combining site-specific engineering data with a stochastic representation of future macro-economic conditions. The landing banner states the tool's purpose—to forecast Levelised Cost of Electricity (LCOE) together with the Weighted-Average Cost of Capital (WACC) and the Return on Equity (ROE) by "forecasting future macro-economic factors—such as inflation, interest rates, capacity factor, and operating expenses (OPEX) in real-world future scenarios.

2.4.1 Data input by the user

The webpage requests sixteen variables, grouped into four thematic blocks. Each entry box is accompanied by contextual “info” links and, where appropriate, a *Fix* checkbox that lets the analyst hold a parameter constant rather than sampling it stochastically. All fields accept decimal values; units are explicitly stated next to each label so that dimensional consistency is preserved at data-entry stage. The table below shows the data input required by the user and the outputs of the MARINEWIND full LCOE tool.

Input by the user	Output of the MARINEWIND LCOE tool
Country	Range of possible LCOEs
Preferred currency	Median LCOE
Capacity of the plant	Range of possible WACCs
Inflation rate	Median of WACC
Interest on debt rate	Range of Possible ROEs
Equity ratio	Median ROE
Corporate tax rate	NREL LCOE
Feed in Tariff	1000 simulated paths for each macroeconomic variable
CAPEX	1000 simulated LCOE based on different macroeconomic scenarios and wind turbine energy production loss
OPEX	
Weibull scale factor	
Weibull shape factor	
Capacity factor for NREL LCOE	

Macroeconomic data:

Preferred currency (USD / GBP / EUR) defines the reporting unit for every monetary output. *Inflation rate* (%) and *nominal interest rate* (%) specify the starting points for two stochastic macro-series; if their *Fix* boxes are ticked the model treats them as deterministic constants. *Corporate income-tax rate* (%) captures the statutory levy used when the tool converts pre-tax operating surplus into after-tax net income, a step that affects both ROE and the after-tax cost of debt. *Share of equity* (%) sets the opening capital-structure ratio and, when left unfixed, is resampled in each Monte-Carlo draw to capture the dispersion observed in recent offshore-wind financings. Together these five variables establish the discount-rate landscape against which future cash flows are evaluated.

Revenue framework

The *feed-in tariff* (price per MWh) is the guaranteed offtake price used to compute annual revenue. By changing this value, the user can analyse price resilience (e.g. break-even tariff for a given equity return). If the project sells into a merchant market, the tariff field can accept a forecast average spot price instead. The number of operating hours is not entered directly; instead, hours are inferred from the fixed calendar year multiplied by the capacity factor that the model generates internally.

Capital and operating costs

Total capital expenditure (CAPEX, entered per MW) represents the overnight cost of capital inclusive of development, turbine, platform, mooring, installation and grid-connection costs. The value is escalated to nominal terms inside the engine by the simulated inflation profile before discounting. *Operating expenditure* (OPEX, entered per MW per year) aggregates fixed and variable operations, maintenance, insurance and seabed-lease payments. A checkbox allows the analyst to keep OPEX deterministic; if left unticked the tool draws annual OPEX values from a log-normal distribution centred on the user-supplied mean, thereby reflecting the documented spread of long-term O&M costs in offshore wind. *Project lifetime* (years) fixes the horizon of the discounted-cash-flow simulation and is typically set between 25 and 35 years for floating assets.

Wind resource characterisation

Two Weibull parameters describe the wind-speed regime at hub height: the *shape factor k* and the *scale factor c (λ)*. Default values ($k \approx 1.87$, $c \approx 8.75$ m s^{-1}) correspond to a reference grid cell in the Sicilian Channel at 150 m elevation, drawn from the **New European Wind Atlas**. Users replace these with site-specific statistics if available. Internally the model uses k and c to generate hourly wind-speed series, convert them via an embedded turbine power curve to annual energy, and thus derive the stochastic capacity-factor distribution. No separate input for capacity factor is therefore required.

Ancillary controls

By clicking **Run Annual Simulation**, the page executes a Monte-Carlo routine that samples each unfixed variable and propagates the draws through an annual cash-flow model. The code delivers 10 000 scenario paths (default) and immediately displays the median and 95 % confidence limits for LCOE, WACC and ROE. Two auxiliary buttons refine post-processing: **Show 95 %-CI Graphs** renders interactive plots of the year-by-year confidence bands, while **Download Results (Excel)** exports the entire ensemble for offline audit or sensitivity diagnostics. In this way the tool merges resource uncertainty (wind-speed variability and capacity-factor dispersion) with financing uncertainty (inflation, interest and leverage) inside one reproducible workflow.

Practical advantages of the MARINEWIND input interface

The web form presents every parameter—financial, technical and resource-related—on a single screen. This layout eliminates the need to shuttle between tabs, lowers the risk of transcription errors and makes peer review straightforward, since users can verify the full assumption set at a glance. Each entry box carries its unit and the selected reporting currency is applied globally, ensuring dimensional consistency and avoiding hidden conversions. Analysts can toggle any driver from stochastic to deterministic simply by activating the *Fix* checkbox beside the field. This design supports rapid sensitivity analysis: a user may lock inflation and interest rates to explore pure wind-resource risk, then unblock them to examine combined macro-economic uncertainty, all without rewriting formulas or uploading new spreadsheets. The form requests only top-line figures—total CAPEX, aggregate OPEX, baseline macro variables and two Weibull parameters—inputs that are typically available well before a project reaches front-end engineering design. Detailed breakdowns (for example, turbine-versus-mooring costs) remain optional, lowering the entry barrier for early-stage developers while still allowing granular studies when data mature. Finally, by placing macro-financial variables and Weibull wind statistics side by side, the interface links cost-of-capital dynamics with resource variability in a single workflow. Few traditional spreadsheet calculators achieve this integration. The result is a streamlined, transparent data architecture that supports robust and reproducible LCOE estimates while remaining accessible to users who may have limited modelling experience.

Below we provide a step by step description of the activities and operationality of the LCOE tool:

2.4.2 Simulation of economic variables

The simulation approach embeds a two-tier Monte-Carlo simulation method: the first tier generates year-by-year realisations of the **economic drivers** that govern financing costs and operating cash flows; the second tier synthesises the **wind-resource state** for each operating year and converts it to electrical output. These simulated inputs feed an annual discounted-cash-flow routine that returns the project's principal performance indicators—Lifetime LCOE, WACC, ROE and a degraded capacity-factor series—for every path. One thousand independent paths are generated per click, adequate for stable percentile estimates.

- *Inflation* and *nominal interest* are drawn each year from a **truncated normal distribution** centred on the previous year's value. The standard deviation is set at 5% of the baseline and bounds are imposed (–20% - 7% for inflation; 0% - 20% for interest) to prevent economically implausible outliers.

- The *equity fraction* (share of owners' capital in the project) is modelled with a **beta distribution** whose shape parameters are proportional to the previous-year fraction; the draw is then clipped to 10–40% to reflect typical leverage limits in offshore-wind finance.

2.4.3 OPEX

The OPEX of floating offshore wind farms is simulated annually following Martinez et al. (2024) and Levitt et al. (2012). OPEX is treated as the annually recurring, non-fuel cost of operating a floating-offshore wind farm, encompassing operations and maintenance, insurance, administration, grid and leasing charges, and offshore logistics. In the LCOE context, OPEX is one of the four principal cost drivers alongside CAPEX, discount rate and net capacity factor; its magnitude and uncertainty can materially influence the distribution of levelised costs over the project life. Empirical reviews of operational projects underline both the variability of offshore O&M and the tendency for costs to rise with fleet age, motivating a probabilistic (rather than purely deterministic) representation in lifecycle appraisal.

Baseline parameter and site dependence. The simulation is anchored on an **initial per-MW-year OPEX** input, $OPEX_{base}$, which represents the expected first-year operating cost at the chosen site. For floating projects, OPEX is modelled as the sum of a **fixed site-independent component** and a **distance-to-shore component**, reflecting travel time, fuel and offshore logistics that scale with siting. Following Martínez & Iglesias (2024), a linear adder with distance is applied to represent this variable component; in their European Atlantic mapping study, the total OPEX per MW-year comprises a base term calibrated for a reference site plus a per-kilometre increment to capture access costs. In our specification, the **path-specific baseline mean** in year t is therefore:

$$OPEX = OPEX_{base} + \beta\, d$$

where d is the shore distance and β is the per-distance cost coefficient taken from the literature (with $OPEX_{base}$ and the distance added increment of 30 EUR/mw/km). This treatment mirrors the site-specific OPEX formulation used by Martínez & Iglesias (2024)[2].

Distributional law and bounding. Annual OPEX per MW is simulated as a **bounded continuous random variable** with mean OPEX (initial value of OPEX). To enforce economic plausibility, we employ a **truncated normal distribution** with **explicit lower and upper bounds**[3] and adjusted for technology (floating vs. bottom-fixed), site class and distance. Truncation ensures samples remain within empirically supported intervals while the central tendency stays at the scenario-specific mean.

Temporal dependence (year-to-year persistence). To reflect persistence in operating budgets and gradual drift from ageing of wind turbines, the process exhibits **first-order serial correlation**: once a

[2] https://www.sciencedirect.com/science/article/pii/S2772671124001438#bib0044

[3] https://www1.udel.edu/MAST/873/AP%20Proposals/Andrew%20Levitt-Published%20Paper%202011.pdf

draw for the mean of the simulated OPEXs in year t+1 is accepted for year t, it becomes the **baseline mean for year t+1**, before applying the same truncated stochastic shock in the next period. Note that O&M tends to be higher as equipment ages and that published OPEX observations are dispersed; allowing the baseline to evolve captures this behaviour without imposing a rigid trend.

Scaling to plant level and currency convention. Each annual value for OPEX (currency · MW · yr) is multiplied by installed capacity to obtain the **plant-level OPEX** for that year. In the base specification, OPEX is simulated directly in nominal terms given the model's stochastic treatment of macro-financial variables elsewhere; where contracts index O&M to inflation, an explicit escalation factor can be applied before discounting, consistent with the cash-flow conventions used in LCOE studies.

Integration with the discounted-cash-flow (DCF) loop. For each Monte-Carlo path and operating year: (i) **revenue** is computed from the tariff/price and net MWh; (ii) **OPEX** is the simulated plant-level value described above; and (iii) co-simulated financing variables yield the year-specific WACC used for discounting. Discounted costs (including OPEX) accumulate in the **LCOE numerator** and discounted energy in the **denominator**; the path-level lifetime LCOE is then the ratio of these present-value sums, consistent with the cash-flow definition adopted in the offshore literature. This procedure aligns with the treatment in Levitt et al., where OPEX is a principal component of the cost cash-flow stream and LCOE is defined as the present-value cost divided by the present-value energy.

Interpretation and reporting. Because OPEX recurs annually, its stochastic dispersion contributes directly to the uncertainty in lifetime LCOE. Transparent reporting should therefore include the **median and confidence interval** for OPEX trajectories (per MW-year and plant-level) and their contribution to the spread in LCOE, together with the calibration sources for $OPEX_{base}$, β and lower and upper bounds.

2.4.4 Simulation of Capacity factor

For every year and every path, the program draws a pair of **Weibull parameters**:

- A shape factor *k* from $N(k_{mean}, \sigma_k)$ truncated to ±2 σ.
- A scale factor *c* from $N(c_{mean}, \sigma_c)$ likewise truncated.

Default means and standard deviations (1.8714 ± 0.0759; 8.7498 ± 0.3418 m s^{-1}) represent a Sicilian-Channel reference but may be overridden by the user. The hourly wind-speed density constructed from (k,c) is integrated against an **IEA-15-240-RWT power curve**. The curve itself is reconstructed from a piecewise polynomial fit to the public IEA Task 37 data set; aerodynamic output is capped at 15 MW. A deterministic **ageing factor** (0.64% power-curve derating per operating year) and a fixed 10% **farm-loss allowance** (wake, electrical and availability) are applied before annual energy is scaled to farm size. The resulting energy divided by rated power and 8,760 h yields the *capacity factor* for that year, which directly determines revenue and appears in the per-year output array.

2.4.5 Discounted-cash-flow loop and convergence.

Within each annual loop the model computes:

- **Revenue** = (feed-in tariff) × (net MWh).
- **OPEX** = (sampled OPEX MW^{-1}) × (farm MW).
- **Debt service** = debt share × CAPEX × (sampled interest).

An iterative block redraws the macro variables until the resulting **ROE** falls within a predefined band (–15% - 50%) to rule out economically untenable paths. Once accepted, the code evaluates the **real WACC** for that year as a tax-adjusted blend of equity return and after-tax real debt cost. Discount factors are applied to both annual costs and annual energy; discounted sums accumulate until the final operating year, after which **Lifetime LCOE** is obtained by dividing the present value of costs by the present value of energy.

2.4.6 Output variables

For each of the 1 000 paths the engine stores:

- year-by-year vectors of inflation, interest, equity share, OPEX, WACC, ROE and capacity factor;
- the path-specified Lifetime LCOE.

The client-side script then:

- aggregates lifetime results to compute mean, median and 95 % confidence limits for LCOE, WACC, ROE;
- aggregates year-specific arrays to build annual confidence envelopes;
- renders interactive line charts for the four main time-series (LCOE, WACC, ROE, degraded CF);
- injects HTML tables summarising each path and exports the entire data set to Excel on demand.

This simulation combines probabilistic macro-finance modelling with a wind-resource engine in a single client-side routine, yielding transparent, reproducible distributions for all headline economic indicators of a floating-offshore-wind project.

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3. Financial analysis of floating offshore wind farms

3.1 UK

3.1.1 Data input

For the UK lab, we use the Kincardine floating offshore wind farm as our case study for the comprehensive LCOE tool developed under the MARINEWIND project. The table below provides the initial data input required to conduct the simulation analysis for the UK and the Kincardine specific input variables. The initial **inflation rate (3.8%, bounded 0–10%, truncated normal)** establishes the price index used to move between nominal and real terms. It works in tandem with the interest rate to derive the real cost of debt and to apply the tax shield correctly in the discount rate. The **interest rate on debt (7.4%, bounded 0–14%, truncated normal)** sets the coupon on project borrowing; together with the equity share and the corporate tax rate, it determines the year-by-year weighted average cost of capital (WACC) used for discounting. The **feed-in tariff (271 per MWh in the selected currency)** defines the unit revenue applied to net energy, so it is the anchor for the income side of the cash-flow. The **corporate tax rate (25%)** is used to transform pre-tax operating surplus into after-tax income and to calculate the after-tax cost of debt in WACC.

Wind resource and energy yield. The capacity factor is not imposed directly; it is generated from the site's wind regime using a **Weibull representation**. The **Weibull shape (k = 2.23)** and **Weibull scale (c = 11.329)** are the inputs to the Weibull probability density used to describe hub-height wind speeds. These parameters are mapped through the turbine power curve (with the tool's aging and loss allowances) to produce annual energy and, hence, the effective capacity factor. The table also lists an **annual production loss (0.064%)**, which is a gross-to-net adjustment applied after aggregating turbine output to the farm level (e.g., electrical or availability losses). Finally, the **number of turbines (6)** provides a cross-check on plant configuration and underpins any per-turbine calculations embedded in the power-curve integration.

Project configuration and horizon. The **farm capacity (50 MW)** sets the physical scale for both energy and cost scaling (e.g., converting per-MW OPEX to plant totals). The **operational life (25 years)** defines the analysis horizon for discounting, shaping the relative influence of early versus late cash flows in the LCOE ratio and the evaluation of financing metrics over time.

Capital and operating costs. CAPEX (£7,600,000) identifies the initial investment to be recovered through the levelised cost. In the financing block it is also used, together with the equity share, to size the debt and equity contributions at financial close. (If this figure is intended per MW rather than total, it should be labelled accordingly; otherwise the model treats it as a project-total.) **OPEX** is specified **per MW-year** with an **initial value (£190,000 MW^{-1} yr^{-1})** and **admissible interval (£79 to £270 MW^{-1} yr^{-1}, truncated normal)**. In the calculations, a per-MW value within this interval is used for each operating year, then scaled by 50 MW to obtain the plant's annual operating cost. Providing both a central value and bounds ensures that annual operating costs remain within plausible limits while still reflecting site-specific uncertainty captured in the O&M literature for offshore wind.

Capital structure. The **equity share (initially 18%, bounded 5–80%, beta distribution)** sets the financing mix at financial close and, with the interest rate and tax rate, determines WACC. Lower equity shares (higher leverage) tilt the discount rate closer to the after-tax cost of debt; higher equity shares tilt it toward the equity return. The use of a beta distribution is appropriate because equity share is a proportion confined to [0,1], and the stated bounds reflect typical ranges observed in project finance for offshore wind.

How these inputs work together. With these initial settings, the LCOE numerator (discounted costs) is driven by **CAPEX** and the annual **OPEX** sequence scaled to 50 MW, while the denominator (discounted energy) is generated from the **Weibull-based wind model** adjusted by the stated production loss. The **feed-in tariff** and simulated energy jointly determine annual revenue for the return metrics, and the macro-financial entries (**inflation, interest, tax, equity share**) shape the discounting through **WACC** and the after-tax profitability through **ROE**. Because the table specifies both central values and, where relevant, bounds and a distribution type, the model has enough information to initialise the Kincardine case and vary the inputs in a controlled, well-defined manner when running the analysis.

Notes on clarity and consistency. Two practical checks help maintain dimensional consistency: (i) confirm the unit for the tariff “271” (e.g., £/MWh) and the currency alignment across all monetary inputs; and (ii) confirm whether the CAPEX figure is total-project or per-MW. Explicitly stating these conventions in the input sheet ensures that subsequent results for LCOE, WACC and ROE can be interpreted unambiguously for the Kincardine case

Macroeconomic data for the UK				
	Initial value	**Lower bound**	**Upper bound**	**Distribution density**
Inflation rate	3.8%	0%	10%	Truncated normal distribution
Interest rate on debt	7.4%	0%	14%	Truncated normal distribution
Feed in Tarif	271			
Tax rate	25%			
Capacity factor				

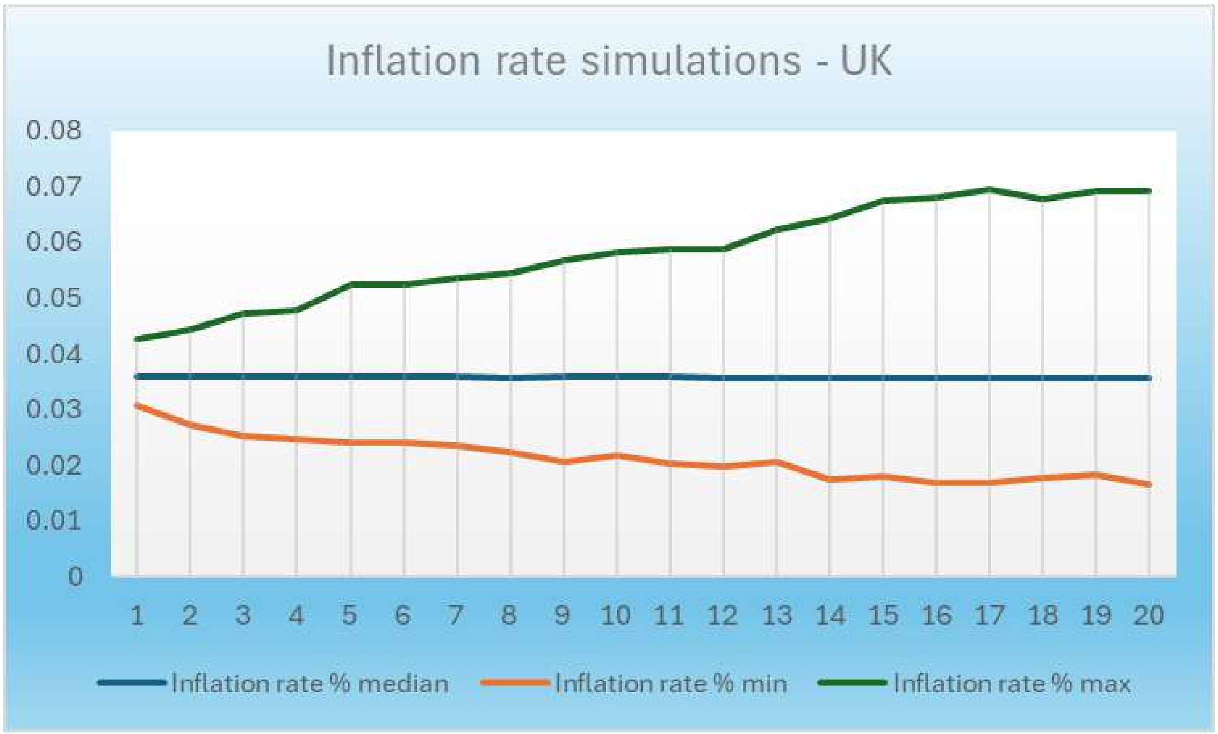
Weibull Shape factor	2.33			Weibull partial distribution function
Weibull scale factor	11.329			Weibull partial distribution function
Number of turbines	6			
Annual production loss	0.064%			
Site specific data				
Capacity of the Farm	50 mw			
Operational years of the farm	25			
CAPEX	£ 7,600,000			
OPEX	£200,000 MW/year	£79 MW/year	£270 MW/year	Truncated normal distribution
Equity share	18%	5%	40%	Random Beta Distribution

3.1.2 Empirical findings UK

3.1.2.1 Macroeconomic variables simulation results

3.1.2.1.1 Inflation rate

The median inflation path is broadly flat at about 3.6% throughout the horizon, easing only slightly to 3.55% by year 20. The interval between the lowest and highest values widens over time—from 3.08–4.27% in year 1 to 1.65–6.93% by year 20—showing that more extreme outcomes become possible in later years. In the model, inflation interacts with the nominal debt rate to form the real cost of debt and therefore influences WACC. When prices run higher without matching revenue indexation, operating cash margins compress in nominal terms and ROE can soften; if indexation is aligned on both revenue and key cost lines, inflation mainly flows through the real/nominal conversion with little effect on real LCOE.



	Inflation rate % simulations UK		
Year	median	min	max
1	3.60038	3.08	4.27
2	3.59843	2.74	4.42
3	3.59538	2.53	4.73
4	3.58833	2.48	4.77
5	3.59445	2.42	5.24

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6	3.59623	2.41	5.23
7	3.58167	2.34	5.35
8	3.57566	2.25	5.45
9	3.58248	2.07	5.69
10	3.58636	2.17	5.83
11	3.58486	2.04	5.89
12	3.57735	1.99	5.89
13	3.58025	2.07	6.22
14	3.57237	1.75	6.42
15	3.57861	1.8	6.74
16	3.57974	1.68	6.8
17	3.5724	1.7	6.94
18	3.56358	1.77	6.77
19	3.56738	1.84	6.91
20	3.55394	1.65	6.93

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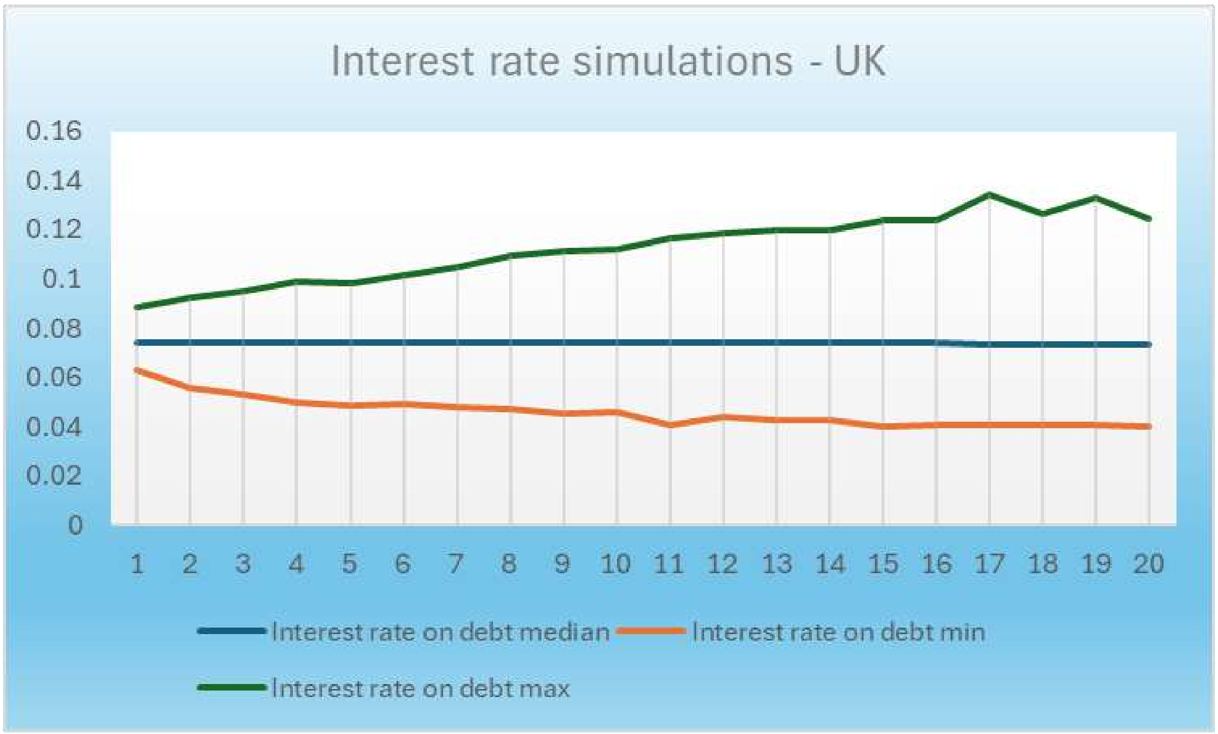
3.1.2.1.2 Interest rate on debt

Borrowing costs start near 7.40% and drift a touch lower to about 7.33% by year 20, while the upper end of the range allows for stress years (roughly 12–13% mid-life) and the lower end stays close to 4%. Because debt is a large share of the capital stack, even modest changes in the coupon move the after-tax cost of debt and therefore WACC. Higher-rate years push up debt service and reduce residual cash to equity, lowering ROE in those years. A lower coupon has the opposite effect and, via a lower WACC, tends to reduce LCOE by down-weighting long-dated costs and valuing later MWh more.



Interest rate on debt - UK			
Year	median	min	max
1	7.39601	6.31	8.83
2	7.39798	5.59	9.23

3	7.40204	5.35	9.51
4	7.38807	5	9.88
5	7.41279	4.88	9.85
6	7.40969	4.91	10.13
7	7.39836	4.83	10.5
8	7.41813	4.71	10.95
9	7.42496	4.54	11.12
10	7.43321	4.6	11.18
11	7.43801	4.1	11.64
12	7.42417	4.41	11.85
13	7.41814	4.28	11.96
14	7.40043	4.27	12
15	7.39872	4.04	12.4
16	7.38994	4.11	12.35
17	7.37282	4.1	13.43
18	7.35604	4.05	12.66

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19	7.33432	4.06	13.3
20	7.32949	4	12.45

3.1.2.1.3 Equity fraction

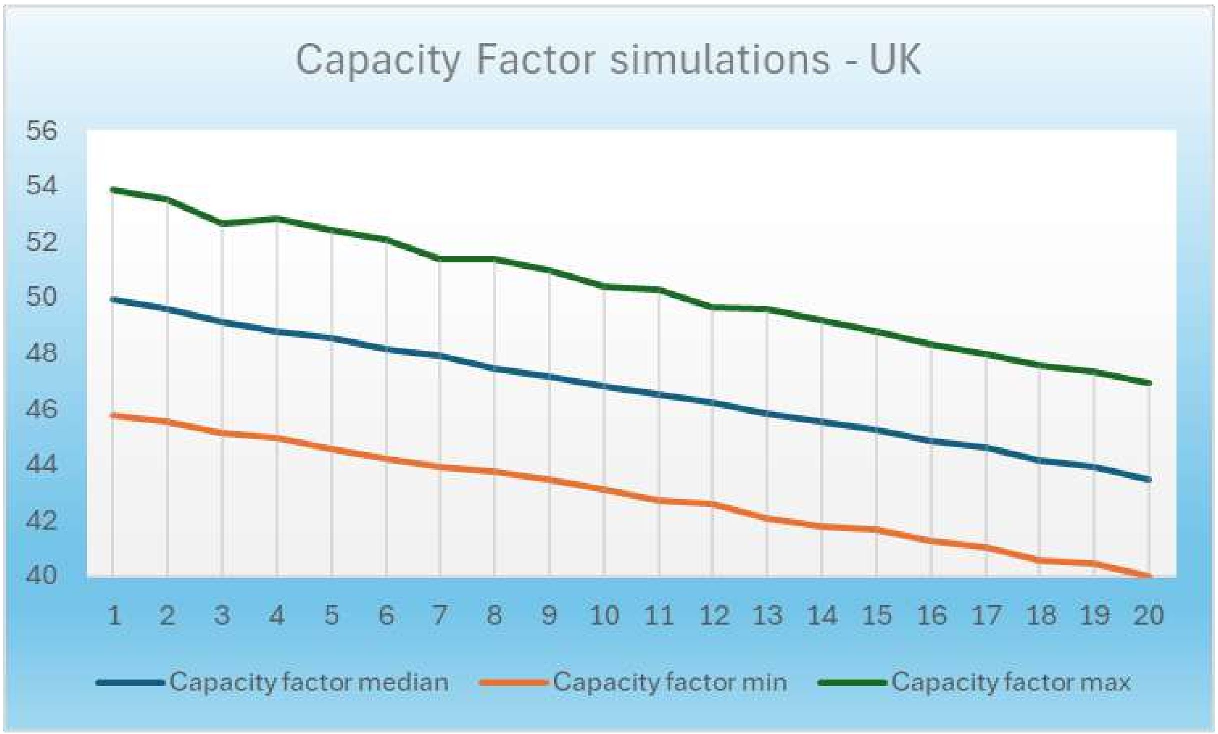
The average equity share declines steadily from about 30% in year 1 to about 24% by year 20, bounded within 10–40% each year. This tilt toward debt increases the weight of cheaper, tax-shielded capital and is a principal reason the model's WACC falls over time. The smaller equity base also amplifies percentage movements in ROE for a given cash-flow swing, contributing to wider ROE tails in some years. On LCOE, the increased use of debt typically lowers the discount rate applied to future costs and energy, which—other things equal—pulls LCOE down and partly offsets the effect of ageing on generation.

	Equity fraction - UK		
Year	**median**	**min**	**max**
1	29.8508	13.95	40
2	29.17115	10	40
3	28.8296	10	40
4	28.21686	10	40
5	27.76798	10	40
6	27.13349	10	40
7	26.5551	10	40
8	26.01154	10	40

9	25.45398	10	40
10	25.42682	10	40
11	25.14965	10	40
12	24.79131	10	40
13	24.70866	10	40
14	24.75405	10	40
15	24.36058	10	40
16	24.35178	10	40
17	23.87881	10	40
18	23.93609	10	40
19	23.71688	10	40
20	23.87141	10	40

3.1.2.2 Capacity factor

median capacity factor declines smoothly from roughly 50.0% in year 1 to about 43.5% in year 20. The minimum and maximum values also ease downward (for example, maxima contract from ~53.9% to ~46.9%), indicating that the upside envelope narrows with age. Because many cost items are quantity-independent, lower CF spreads fixed and quasi-fixed costs over fewer MWh, raising the unit cost of energy. In the model, this late-life erosion in CF places upward pressure on LCOE; the concurrent decline in WACC partly counterbalances that pressure by reducing the present-value weight of long-dated costs and valuing later-year energy more favourably.



Capacity factor			
Year	median	min	max
1	49.95074	45.76	53.88
2	49.57269	45.52	53.52

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3	49.1352	45.15	52.64
4	48.7711	44.98	52.8
5	48.52352	44.54	52.44
6	48.14211	44.24	52.07
7	47.8833	43.93	51.39
8	47.46682	43.73	51.36
9	47.13443	43.45	51
10	46.80643	43.1	50.41
11	46.49569	42.71	50.28
12	46.20908	42.62	49.67
13	45.82782	42.1	49.56
14	45.51684	41.79	49.2
15	45.2264	41.67	48.79
16	44.87533	41.26	48.3
17	44.6269	41.06	47.99
18	44.15487	40.57	47.59

19	43.89964	40.47	47.36
20	43.47509	39.99	46.92

3.1.2.3 OPEX

Average OPEX moves down early from about £158k/MW-yr in year 1 to a stable level near £190k/MW-yr, with a tight band around that median across the horizon. Because OPEX recurs annually, its level materially shapes the present-value cost numerator of LCOE. The quick convergence to a stable level and the narrow band limit the contribution of OPEX to LCOE dispersion. Years that combine lower CF with higher OPEX are the most demanding for equity cash flows, often coinciding with lower ROE; conversely, steady OPEX helps preserve margins and supports the WACC reductions obtained from the capital-structure shift.

OPEX - UK			
Year	median	min	max
1	207810.5	167409.6	223995.3
2	198375.1	164098.4	223993.6
3	195939.5	164030.3	223998
4	194619.3	164034.8	223996.6
5	194109.5	164122.6	223875.6
6	193461.9	164005.5	223971.8
7	194065.5	164001.8	223868.9
8	193837.7	164025.2	223995.3

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9	194386.1	164028.2	223885.9
10	194546.8	164127.5	223959.7
11	194982	164220.6	223974.4
12	194143.4	164016.3	223890.2
13	194051.6	164016	223958.3
14	194034.8	164076.7	223971.3
15	194232.1	164020.8	223979.4
16	194378.8	164114.2	223997.6
17	194116.8	164054.5	223814.6
18	193785	164068.6	223999
19	194117.1	164314.5	223994.7
20	193825.6	164247.9	223958.1

3.1.2.4 WACC

The discount rate falls from about 10.82% in year 1 to roughly 7.47% by year 20, with narrower tails in later years. This pattern reflects the combination of slightly easing coupons, higher debt weight as the project matures, and a lower perceived operating risk after commissioning. A lower WACC reduces LCOE by decreasing the present-value weight of cost streams that occur far in the future and by assigning more value to later-year MWh. It also cushions the LCOE impact of the gradual decline in CF, which is why the model's lifetime LCOE distribution remains relatively concentrated around the reported median.

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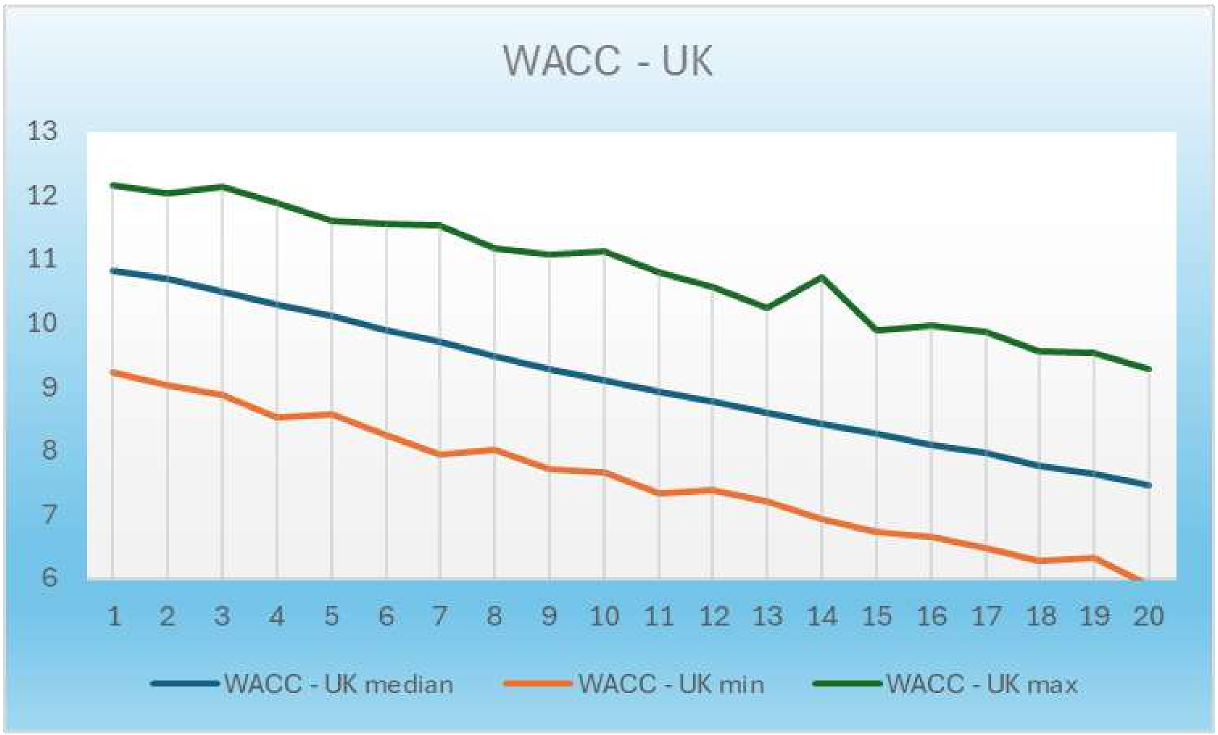

WACC - UK			
Year	median	min	max
1	10.81904	9.23	12.15
2	10.69191	9.02	12.03
3	10.48912	8.87	12.14
4	10.27825	8.52	11.88
5	10.10157	8.58	11.61
6	9.89447	8.25	11.54

7	9.70326	7.93	11.52
8	9.48833	8.02	11.17
9	9.28696	7.71	11.06
10	9.11028	7.66	11.12
11	8.9338	7.33	10.8
12	8.77662	7.39	10.56
13	8.58685	7.2	10.25
14	8.41744	6.93	10.72
15	8.2648	6.73	9.89
16	8.09395	6.66	9.97
17	7.95639	6.46	9.85
18	7.76468	6.26	9.56
19	7.63154	6.32	9.53
20	7.46757	5.9	9.27

3.1.2.5 ROE

Median ROE begins high—around 18–19% in the early years—and trends down to about 9% by year 20, with widening dispersion and occasional negative outcomes in late life. The pattern is consistent with healthy early-life margins when CF is strongest, followed by thinner residual cash as CF eases and OPEX continues, with debt-service requirements varying by interest-rate realisation. ROE itself does not enter the LCOE calculation, but decisions taken in response to ROE pressure—such as refinancing

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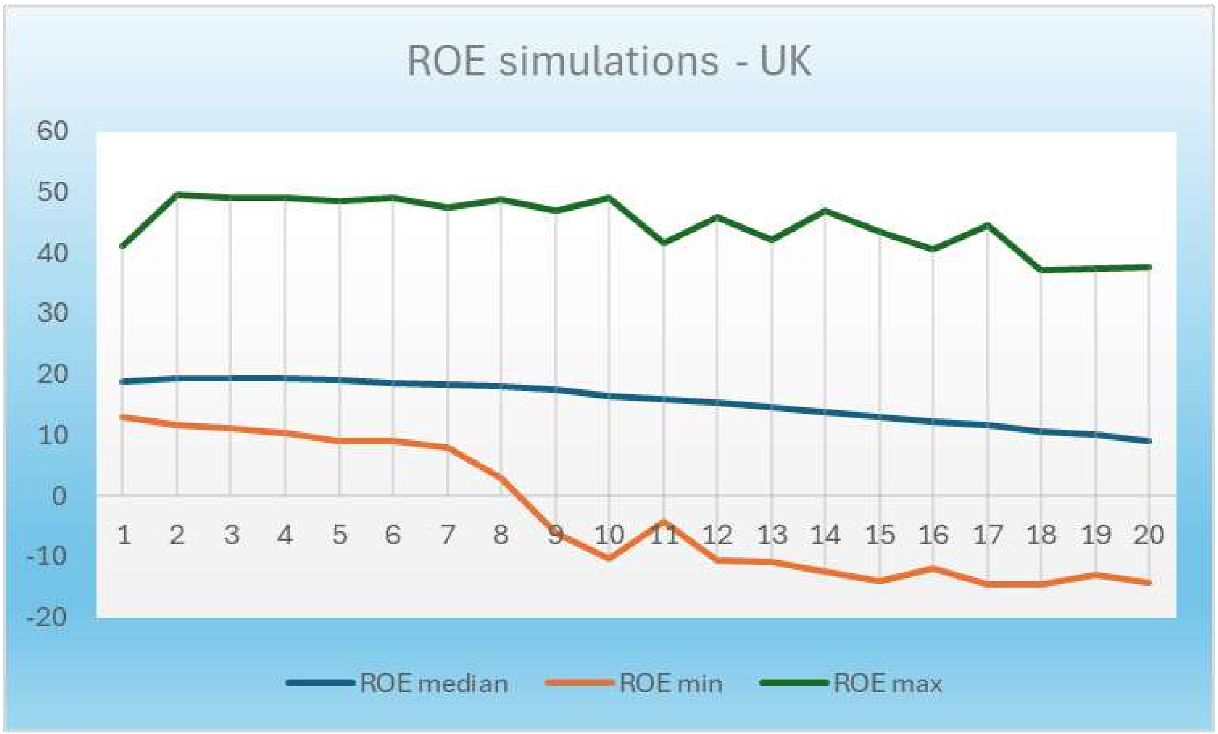
to lower debt cost or modestly adjusting leverage—feed back into WACC and thus affect LCOE. In aggregate, the results show CF ageing nudging ROE lower over time, while financing improvements and contained OPEX help stabilise returns and keep lifetime LCOE close to the ~£195/MWh median.



ROE - UK			
Year	median	min	max
1	18.82736	12.98	41.04
2	19.39916	11.71	49.59
3	19.43319	11.07	49.09
4	19.41251	10.46	49.13
5	19.14202	9.08	48.47

6	18.67737	9.13	49.14
7	18.30325	7.89	47.5
8	18.0075	2.88	48.7
9	17.5069	-5.96	46.79
10	16.48202	-10.29	48.95
11	15.94025	-4.29	41.69
12	15.26984	-10.6	45.98
13	14.56513	-10.9	42.03
14	13.89889	-12.38	46.86
15	12.9345	-14.01	43.53
16	12.24388	-11.99	40.57
17	11.6831	-14.48	44.51
18	10.70988	-14.61	37.13
19	10.0769	-12.94	37.43
20	9.0773	-14.23	37.72

3.1.2.6 LCOE

The table below presents the **MARINEWIND LCOE analysis** for the **Kincardine floating offshore wind farm (UK)**. Results reflect **multiple future economic scenarios**—including variations in inflation, debt costs, capital structure, and tax—together with the **expected deterioration in wind-turbine electricity generation over time** (capacity-factor decline and operational losses). The **model LCOE** is reported alongside a fixed-charge **simplified LCOE** for benchmarking, while the accompanying **WACC** and **ROE** ranges summarise financing and equity-return conditions consistent with those scenarios. Taken together, these indicators provide a decision-grade view of Kincardine's levelised cost of energy under plausible macro-financial paths and performance ageing, showing how changing discount rates, operating costs, and gradual reductions in net MWh combine to shape the project's lifetime unit cost of electricity. the **model LCOE** for Kincardine centres at **£194.78/MWh**, with a **minimum of £173.01/MWh** and a **maximum of £209.61/MWh** across the simulated futures. This band is consistent with a setting where two forces largely counterbalance: (i) a **gradual reduction in annual net MWh** due to turbine performance ageing and operational losses; and (ii) **improving financeability over time**, reflected in lower effective discount rates. The result is a distribution that is neither excessively tight (ignoring risk) nor overly wide (suggesting instability). The **simplified NREL LCOE** of **£202.17/MWh** sits above the model median because a fixed-charge calculation does not incorporate year-by-year movements in leverage, interest costs, and discounting that the MARINEWIND analysis applies to cash flows.

The **WACC** summary shows a **median of 8.60%** with a **range of 6.57–10.93%**. Scenarios at the lower end correspond to conditions with stronger debt capacity and moderate coupons, which increase the present value of later-life energy and temper the cost impact of ageing. Scenarios at the upper end capture periods of tighter credit or higher coupons, which raise the cost of capital and shift LCOE toward the top of the reported range.

The **ROE** distribution—**median 13.35%**, **1.40–28.93%**—reflects how residual cash to equity evolves once debt service and operating costs are met under the same economic and performance trajectories. Higher-return cases align with years that combine favourable borrowing terms and stronger generation; lower-return cases coincide with weaker output and/or costlier debt. Importantly, even the lower tail remains positive on a lifetime basis, indicating that the project's equity performance is preserved across the plausible scenarios evaluated, while the LCOE remains concentrated at just under **£200/MWh** when both macroeconomic variability and expected generation losses are considered.

Model	Median	Minimum	Maximum
LCOE	£227.16	£215.37	£249.61

simplified LCOE	£238.20	£238.20	£238.20
WACC	8.69%	6.57%	10.93%
ROE	13.35%	1.40%	28.93%

3.2 Italy

3.2.1 Data input

The table below provides **Italy's input data** for the MARINEWIND LCOE analysis of a FOWT in Sicily. As with the UK case, the focus is on how each entry is used in the model and how, together, they shape the cost-of-energy evaluation.

Macroeconomic environment. The initial **inflation rate (4.33%)**, with **0–10% bounds** and a **truncated-normal** density, sets the price level used to reconcile nominal and real terms. It interacts with the debt coupon when deriving the real cost of debt and with the corporate tax rate when applying the interest tax shield. The **interest rate on debt (8.1%)**, bounded **0–14%** and sampled under the same density, determines the financing cost of the debt tranche year by year. The **feed-in tariff (185 per MWh, EUR)** is the unit price applied to net energy in the revenue calculation. The **corporate tax rate (22%)** is applied to operating surplus to obtain after-tax income and to compute the after-tax cost of debt used in WACC.

Wind resource and energy yield. The capacity factor is generated from the site's wind regime using a **Weibull representation**. The **shape factor (k = 1.8714)** and **scale factor (c = 8.7499 m s^{-1})** define the wind-speed frequency distribution at hub height. These parameters are mapped through the turbine power curve and adjusted for loss allowances and ageing effects to produce annual net MWh. The separate **annual production loss (0.064%)** is applied as a gross-to-net correction (e.g., electrical and availability losses). This pairing—Weibull parameters plus an explicit loss factor—ensures that energy calculations are driven by physically interpretable inputs rather than an assumed scalar capacity factor.

Site and technical configuration. A **farm capacity of 1,000 MW** with **64 turbines** fixes the project scale and underpins per-turbine checks against the power-curve model. The **operating life of 20 years** defines the valuation horizon for discounting costs and energy. Relative to the UK case, the Italian project is an order of magnitude larger in capacity, which magnifies the influence of per-MW assumptions (CAPEX/MW and OPEX/MW-yr) on total cash flows.

Capital and operating costs. CAPEX is provided per MW at **EUR 4,761,200/MW**, which the model scales by 1,000 MW to obtain the total investment used in the initial cash-flow and in sizing debt and equity at financial close. **OPEX is specified per MW-year** with an **initial value of EUR 141,000/MW-yr**, an **admissible interval of EUR 60,000–171,000/MW-yr**, and a **truncated-normal** density. During the analysis, an annual per-MW value within this interval is applied and then scaled to plant level. Providing both a central value and bounds ensures that yearly operating costs remain within plausible industry limits for a large-scale floating project.

Capital structure. The **equity share** is set initially at **30%**, with bounds of **10–50%** and a **beta distribution** to reflect that it is a proportion. This input sets the opening leverage and, together with the debt coupon and tax rate, determines the weighted-average cost of capital (WACC) used for discounting. The tighter upper bound (50%) relative to the UK case implies a narrower range of low-leverage scenarios, keeping the financing mix closer to typical European offshore-wind practice.

How these inputs work together. With a 1 GW plant, small changes in **OPEX/MW-yr** or **CAPEX/MW** translate into large absolute shifts in cash flows. The **Weibull parameters** determine the net MWh denominator for LCOE after loss adjustment; the **feed-in tariff** and those same MWh drive revenue for ROE. The **interest rate**, **equity share**, and **tax rate** together set **WACC**, which weights all future costs and energy in present-value terms. Compared with the UK/Kincardine case, the Italian inputs feature a **higher initial inflation and debt rate**, a **lower tariff**, a **larger plant**, and a **20-year horizon**; taken together, these differences tilt the analysis toward stronger scale effects (1 GW), greater sensitivity to per-MW OPEX discipline, and a pronounced role for the Weibull-driven energy yield in stabilising unit costs over the shorter project life.

Notes on units and consistency. All monetary figures are in **EUR**; tariff is interpreted as **EUR/MWh**, CAPEX as **EUR/MW**, and OPEX as **EUR/MW-yr**. The number of turbines, farm capacity, and Weibull parameters should correspond to the same hub height and reference turbine used in the power-curve integration to maintain internal consistency. Clarifying these conventions in the input sheet ensures that the subsequent LCOE, WACC and ROE results for the Italian case can be interpreted unambiguously.

Macroeconomic data - Italy				
	Initial value	**Lower bound**	**Upper bound**	**Distribution density**
Inflation rate	4.33%	0%	10%	Truncated normal distribution
Interest rate on debt	8.1%	0%	14%	Truncated normal distribution
Feed in Tarif	185			

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Tax rate	22%			
Capacity factor				
Weibull Shape factor	1.8714			Weibull partial distribution function
Weibull scale factor	8.7499			Weibull partial distribution function
Number of turbines	64			
Annual production loss	0.064%			
Site specific data				
Capacity of the Farm	1000 mw			
Operational years of the farm	20			
CAPEX/mw	EUR 4,761,200			
OPEX	EUR 141,000 MW/year	EUR 60 MW/year	EUR 171 MW/year	Truncated normal distribution
Equity share	30%	10%	40%	Random Beta Distribution

3.2.2 Empirical findings

3.2.2.1 Macroeconomic variables simulation results

3.2.2.1.1 Inflation rate

The inflation path for the Sicily case is anchored around **~4.33%** at the outset and remains close to that level through Year 20 (median ~4.29%), while the annual min–max envelope gradually widens (from **3.73–5.08%** in Year 1 to **1.81–6.95%** by Year 20). This profile keeps real/nominal conversions relatively stable on average, but the broader tails later in life admit scenarios with materially higher or lower price levels. In the cash-flow, inflation interacts with the nominal coupon to set the real cost of debt

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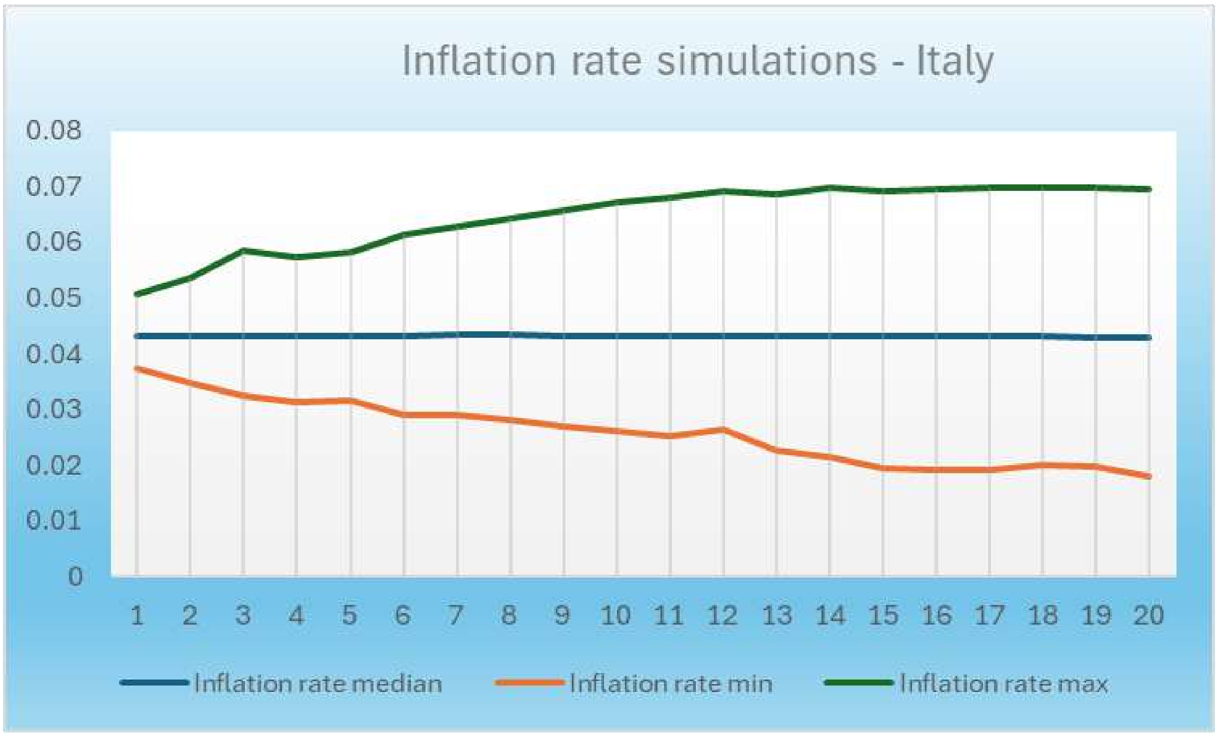
(and therefore WACC) and, where contracts are indexed, it influences the nominal trajectory of OPEX and revenues that feed into ROE and, indirectly via discounting, LCOE.

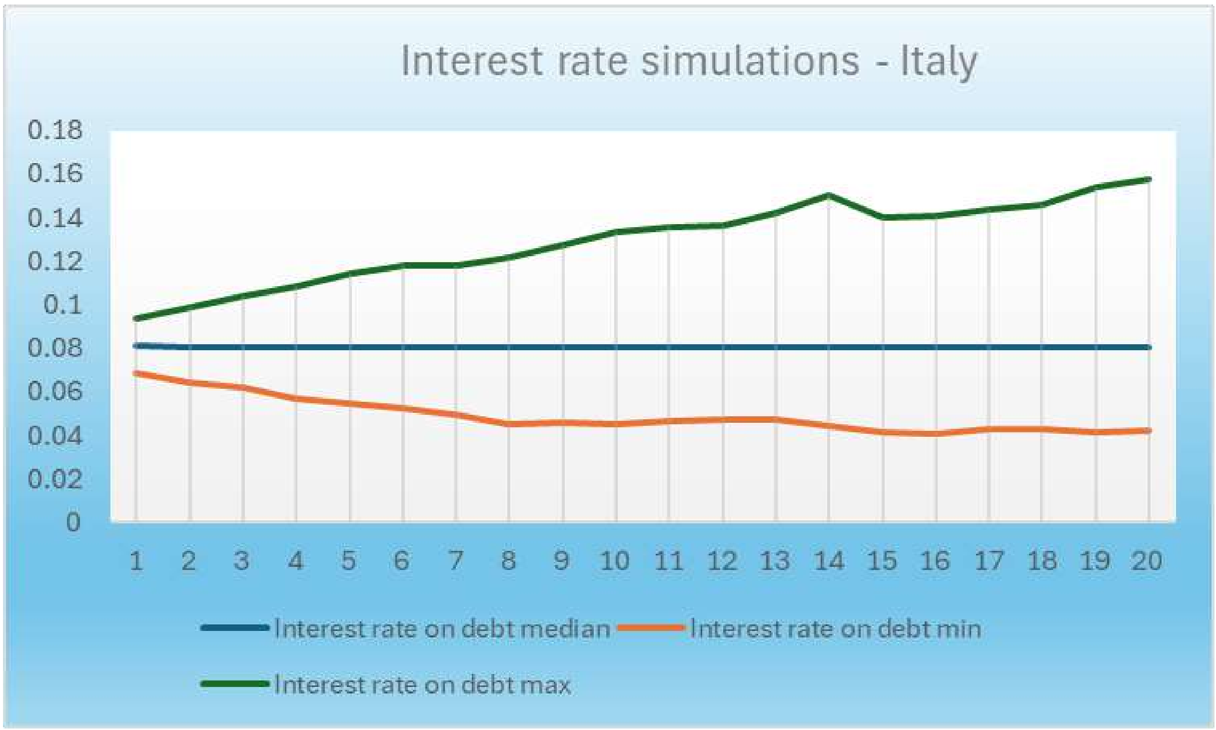


	Inflation rate - Italy		
Year	**median**	**min**	**max**
1	4.32674	3.73	5.08
2	4.32479	3.49	5.36
3	4.31753	3.26	5.84
4	4.31857	3.14	5.74
5	4.32812	3.15	5.83

6	4.33032	2.91	6.13
7	4.33805	2.9	6.28
8	4.33666	2.82	6.43
9	4.33035	2.71	6.58
10	4.3266	2.61	6.73
11	4.33106	2.53	6.8
12	4.32362	2.63	6.91
13	4.32079	2.26	6.85
14	4.32432	2.14	6.98
15	4.31962	1.96	6.92
16	4.31492	1.91	6.96
17	4.31208	1.93	6.97
18	4.30578	2.01	6.97
19	4.29646	1.97	6.99
20	4.29142	1.81	6.95

3.2.2.1.2 Interest rate on debt

Average borrowing costs sit near **~8.10%** throughout, with slight drift (ending ~8.03–8.08% by Year 20). The dispersion increases over time, with upper bounds reaching the **14–16%** region in late life, while lower bounds fall toward **~4–5%**. Since debt typically forms the larger share of the capital mix, this variable is a principal driver of the after-tax cost of debt and thus WACC. Higher-rate realizations tighten annual equity margins and push WACC upward—conditions that tend to elevate LCOE; more benign rate years do the reverse.



Interest rate on debt - Italy			
Year	median	min	max
1	8.09414	6.87	9.35
2	8.07891	6.44	9.88

3	8.07325	6.2	10.39
4	8.05767	5.7	10.86
5	8.04135	5.5	11.46
6	8.04005	5.28	11.79
7	8.05199	4.97	11.81
8	8.07169	4.5	12.16
9	8.07693	4.57	12.76
10	8.07963	4.5	13.37
11	8.0657	4.68	13.52
12	8.05546	4.76	13.66
13	8.06266	4.73	14.24
14	8.04181	4.47	15
15	8.08042	4.12	14.03
16	8.07131	4.05	14.08
17	8.05044	4.29	14.33
18	8.01675	4.3	14.55

19	8.01724	4.17	15.41
20	8.02742	4.25	15.74

3.2.2.1.3 Equity fraction

The median equity share declines from **~29.9%** (Year 1) to **~23.2%** (Year 20), within the **10–40%** bounds. This migration toward higher leverage increases the weight of cheaper, tax-shielded debt, contributing to the observed decline in WACC. A thinner equity base, however, amplifies percentage movements in ROE for a given cash-flow swing. For LCOE, the leverage-driven reduction in WACC lowers the present-value weight of future costs and helps to temper the impact of performance ageing on unit costs.

	Equity fraction - Italy		
Year	median	min	max
1	29.91928	14.07	40
2	29.41545	10	40
3	28.99035	10	40
4	28.05727	10	40
5	27.55049	10	40
6	27.09858	10	40
7	26.70848	10	40
8	26.25242	10	40

9	25.55526	10	40
10	24.87413	10	40
11	24.74819	10	40
12	24.3956	10	40
13	24.22233	10	40
14	24.06641	10	40
15	23.88425	10	40
16	23.47437	10	40
17	23.13041	10	40
18	23.16243	10	40
19	23.28727	10	40
20	23.21612	10	40

3.2.2.2 Capacity factor

median capacity factor starts near **34.4%** and declines smoothly to **~30.1%** by Year 20; the annual minima and maxima follow similar descending paths (e.g., maxima from **~38.7%** to **~33.7%**). With many cost elements independent of output, this erosion in CF spreads fixed and quasi-fixed costs over fewer MWh, placing upward pressure on LCOE in later years. The contained spread each year indicates that, while performance weakens with age, annual variability around the median remains moderate; discount-rate relief (see WACC) partly offsets the CF effect in the lifetime metric.

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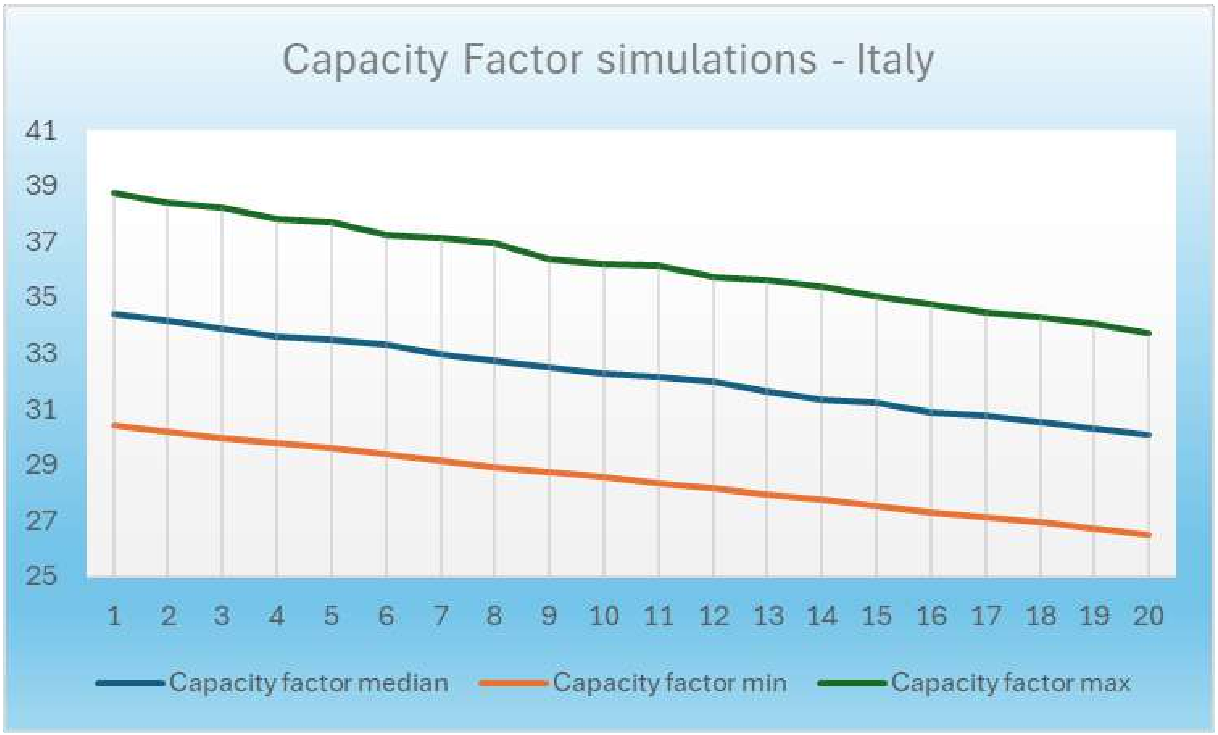

Capacity factor			
Year	median	min	max
1	34.4251	30.4	38.74
2	34.16125	30.18	38.42
3	33.89688	29.96	38.22
4	33.61198	29.77	37.82
5	33.468	29.6	37.7
6	33.29085	29.36	37.25

7	32.96724	29.16	37.1
8	32.76438	28.95	36.93
9	32.49491	28.75	36.38
10	32.29579	28.56	36.23
11	32.1492	28.34	36.13
12	31.96533	28.15	35.72
13	31.65358	27.94	35.63
14	31.37683	27.74	35.37
15	31.24722	27.53	35.02
16	30.90615	27.33	34.76
17	30.75677	27.14	34.47
18	30.51367	26.94	34.29
19	30.29219	26.72	34.08
20	30.09052	26.52	33.73

3.2.2.3 OPEX

Annual OPEX per MW remains tightly clustered around **€143–145k/MW-yr** after a modest early movement, with bounds consistently near **€114k–€174k/MW-yr**. Given the 1 GW scale, this stable per-MW profile is important: OPEX recurs every year and thus materially shapes the present-value cost numerator of LCOE. The bounded interval limits the contribution of OPEX to extreme outcomes. Years in which lower CF coincides with the upper end of the OPEX range are the most demanding for equity cash flows (lower ROE) and tend to nudge LCOE upward within its reported range.

OPEX - Italy			
Year	median	min	max
1	142758.3	114015.6	173971.9
2	143508	114103.1	173996.5
3	143339.5	114044.8	173847.3
4	143376.7	114005.5	173988.5
5	143632	114080.3	173860.5
6	143297.9	114000.7	173983.9
7	143714.3	114044.4	173698
8	144378.7	114064.8	173933.9
9	144143.1	114045.7	173917.5
10	143456.4	114019.9	173926.8
11	143303.4	114114.9	173968.6
12	143084.8	114003.8	173986.2

13	143549.2	114056	173997.2
14	144846.6	114090.8	173860.3
15	143762.1	114088.2	173994.9
16	143393.7	114001.7	173879.9
17	144477.2	114119.2	173967.6
18	143817	114014.9	173973.2
19	142597.4	114010.7	173756.1
20	143211.5	114060.9	173977.4

3.2.2.4 WACC

The discount rate exhibits a **clear downward trajectory**, falling from **~10.82%** (Year 1) to **~6.72%** (Year 20); tails also narrow over time (late-life minima near **~4.5–5%**, maxima near **~9–10%**). This pattern reflects the combined effects of steady coupons on average, increasing debt weight, and maturation of the operating risk profile. Lower WACC reduces the PV of long-dated costs and raises the PV weight of later-year MWh, directly **reducing LCOE** and mitigating part of the upward pressure arising from CF decline.

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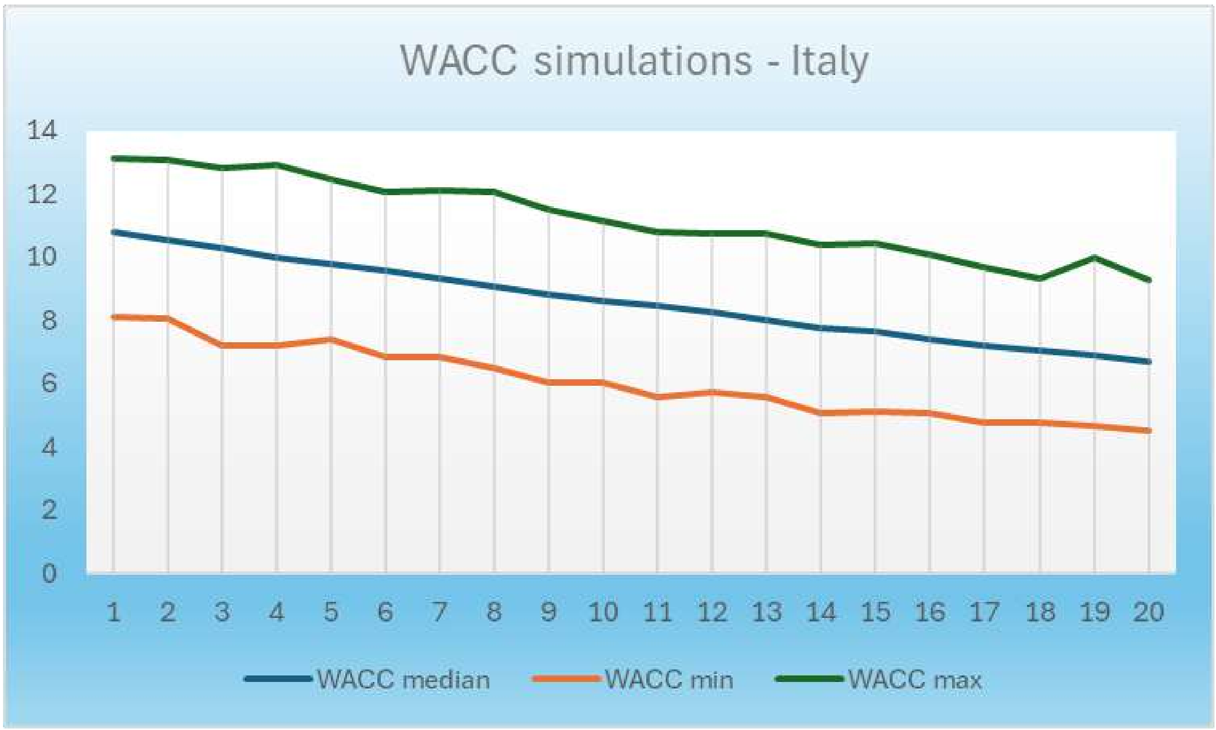

WACC			
Year	median	min	max
1	10.81597	8.1	13.13
2	10.53373	8.06	13.05
3	10.28253	7.22	12.82
4	9.9988	7.22	12.91
5	9.78808	7.39	12.48
6	9.58369	6.84	12.05

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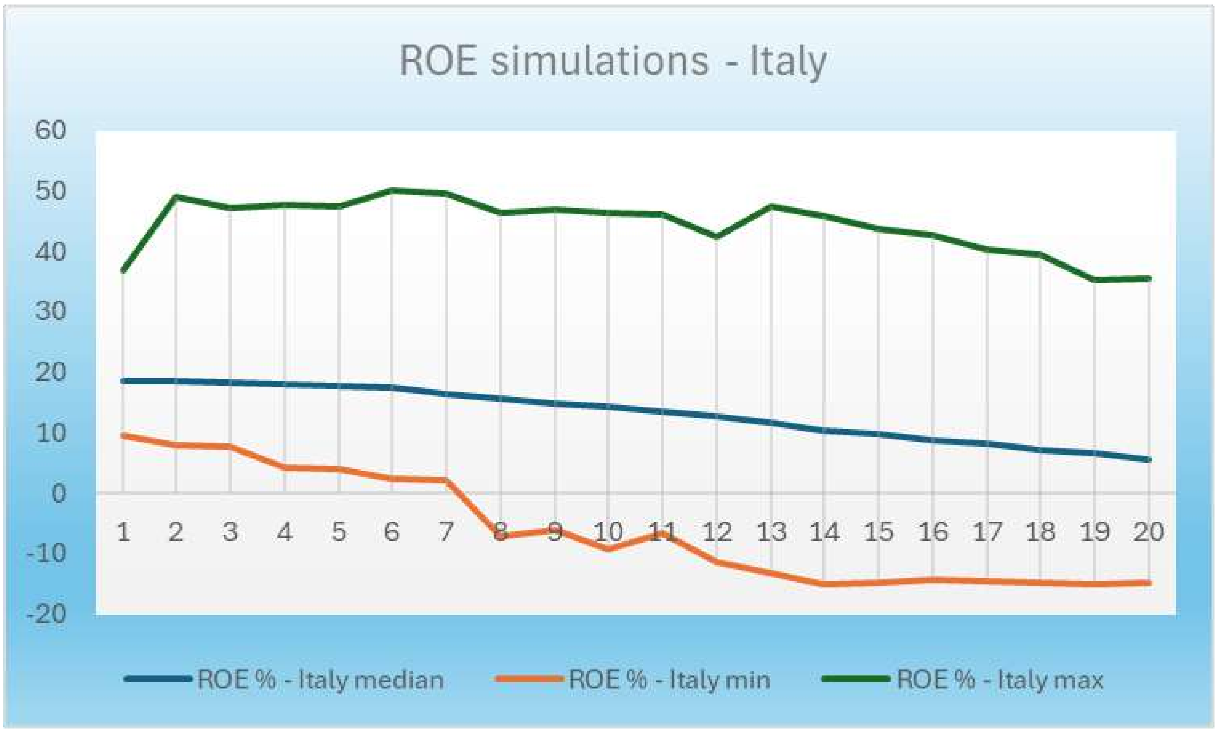
7	9.3113	6.84	12.1
8	9.07368	6.52	12.07
9	8.82967	6.02	11.49
10	8.62903	6.03	11.15
11	8.45842	5.61	10.78
12	8.26572	5.72	10.76
13	8.0209	5.59	10.74
14	7.77238	5.1	10.38
15	7.63928	5.11	10.42
16	7.40873	5.06	10.08
17	7.2081	4.79	9.67
18	7.04662	4.77	9.35
19	6.91057	4.66	9.99
20	6.72027	4.5	9.27

3.2.2.5 ROE

median ROE starts at **~18.7%** and declines to **~5.5%** by Year 20, with widening dispersion and negative annual values appearing in a subset of later-life scenarios. The trend is consistent with gradually weaker output (lower CF), steady OPEX, and occasional higher-rate years increasing debt service. While

ROE is not an input to the LCOE formula, actions taken in response to ROE compression—such as refinancing or modest adjustments to leverage—alter WACC and therefore influence LCOE. Overall, the Sicily case shows the familiar interplay: **CF ageing** tends to weaken annual returns, **OPEX discipline** helps contain downside, and **declining WACC** provides counterbalance in the lifetime cost of energy.



ROE % - Italy			
Year	median	min	max
1	18.7043	9.53	36.87
2	18.54099	7.96	49.11
3	18.29414	7.73	47.05
4	18.15852	4.19	47.65

5	17.84685	4.08	47.38
6	17.49271	2.55	50
7	16.51503	2.16	49.6
8	15.63313	-7.03	46.38
9	14.90323	-6.14	46.82
10	14.26533	-9.2	46.25
11	13.49946	-6.58	46.1
12	12.84563	-11.3	42.51
13	11.66981	-13.12	47.42
14	10.40185	-14.98	45.81
15	9.78785	-14.86	43.83
16	8.68107	-14.38	42.79
17	8.12031	-14.5	40.25
18	7.25559	-14.76	39.47
19	6.54546	-14.93	35.17
20	5.53236	-14.85	35.53

3.2.2.6 LCOE analysis

The table reports the outcomes for the Sicily case under the MAIRNEINWD LCOE model and, for comparison, a fixed-charge “simplified” nrel LCOE benchmark. The **model LCOE** centres at **EUR 186.60/MWh**, with a **minimum of EUR 170.41/MWh** and a **maximum of EUR 193.66/MWh**. This is a **narrow distribution** (≈ EUR 23/MWh wide), indicating that the combination of input ranges-macroeconomic paths, capital structure, OPEX envelope, and the projected capacity-factor trajectory-translates into a relatively concentrated lifetime unit cost. The **simplified LCOE** of **EUR 194.24/MWh** sits **above** the model median, consistent with a fixed-rate method that cannot reflect year-by-year movements in leverage and borrowing costs; the dynamic model discounts cash flows with a **declining effective WACC**, yielding a lower central estimate.

The **WACC** summary shows a **median of 6.44%** with a range from **4.02% to 7.11%**. A centre in the mid-6% region implies substantial debt participation at moderate coupons and a tax shield operating over the 20-year horizon. The relatively tight span suggests financing terms that are credible across scenarios without implying pervasive stress. Because WACC weights all future costs and MWh, values toward the lower end reduce the present-value burden of long-dated OPEX and assign greater weight to later-life energy, helping to keep the model LCOE near the **EUR 187/MWh** midpoint despite capacity-factor ageing.

The **ROE** distribution-**median 6.46%**, with a **minimum of −5.84%** and a **maximum of 14.63%**—is wider and notably includes **negative outcomes** in a subset of scenarios. This reflects the residual nature of equity cash flows once debt service and OPEX are met under varying combinations of energy output and borrowing costs. The moderate median indicates that, at the assumed tariff and cost structure, equity performance is positive on average but sensitive to downside combinations (lower output together with higher coupons or upper-band OPEX). Taken together, the indicators depict a Sicilian project whose **cost of energy** is concentrated just below **EUR 190/MWh**, supported by improving discount rates through operations and by operating costs that remain within decision-grade bounds, while **equity returns** are serviceable on average but warrant attention to leverage, refinancing windows, and availability performance to avoid the lower-tail outcomes.

Model	Median	Minimum	Maximum
LCOE	EUR 188.62	EUR 179.11	EUR 208.41
simplified LCOE	EUR 187.7	EUR 187.7	EUR 187.7
WACC	6.44%	4.02%	7.11%
ROE	6.46%	-5.84%	14.63%

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3.3 Portugal

3.3.1 Data input

Below is an interpretation of a planned FOWT in the **Portugal (Atlantic) input table** for a 1 GW floating offshore wind farm. As with the UK and Italy cases, the focus is on what each entry does in the MARINEWIND LCOE analysis and how the inputs jointly shape LCOE, WACC, and ROE once the simulation is run. This data was collected from the MARINEWIND survey.

Macroeconomic environment. The **inflation rate (3.50%, bounds 0–10%, truncated normal)** sets the price index used to convert between nominal and real terms and to apply any indexation conventions in contracts. The **interest rate on debt (7.50%, bounds 0–14%, truncated normal)** establishes the starting coupon for project borrowing; together with the corporate **tax rate (21%)** and the equity share, it determines the after-tax cost of debt and therefore the discount rate applied to cash flows. The **feed-in tariff (€198/MWh)** anchors revenue per unit of net energy. These settings provide the financial backdrop against which operating cash flows are evaluated; they can be updated to match LSEG/official series before running scenarios.

Wind resource and energy yield. Energy output is generated from a **Weibull wind-speed representation** rather than a fixed capacity-factor guess. The **shape factor (k = 2.10)** and **scale factor (c = 9.20 m s^{-1})** define the hub-height wind distribution for the selected offshore cell; these parameters are passed through the reference turbine power curve (with ageing and loss allowances) to obtain annual net MWh. The separate **annual production loss (0.064%)** is a gross-to-net correction applied after aggregating turbine output. Because LCOE's denominator is lifetime net MWh, the Weibull pair is among the most influential inputs; replacing the indicative k–c with values extracted from the **New European Wind Atlas** for the exact site will sharpen the energy estimate.

Site and technical configuration. A **1,000 MW farm** with an indicative **67 turbines** (≈15 MW class) fixes the physical scale of the project and provides a consistency check with the power-curve integration. The **operating life (20 years)** sets the time horizon for discounting costs and energy. Relative to smaller pilots, the 1 GW scale increases the impact of per-MW cost assumptions on total cash flows and magnifies the effect of even modest changes in availability or losses on annual MWh.

Capital and operating costs. CAPEX is specified as **€4,000,000/MW** and is scaled by capacity to obtain the total investment used at financial close and in financing calculations. **OPEX** is **€158,000/MW-year** with bounds **€60,000–€190,000/MW-year** (truncated normal). In the analysis, a per-MW operating cost within this interval is applied each year and then scaled to plant level. Because OPEX recurs annually, its level has a direct effect on the present-value cost ledger in LCOE; the explicit bounds also prevent implausible values from driving results. At 1 GW, a €10k/MW-year change in OPEX shifts annual plant O&M by ~€10 million, so disciplined calibration of this range is important.

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Capital structure. The **equity share** is set at **30%** with bounds **10–50%** and a **beta distribution** to reflect that it is a proportion. This determines initial leverage and, combined with the coupon and tax rate, yields the **weighted average cost of capital (WACC)** used to discount costs and energy. Higher leverage generally lowers WACC by increasing the weight of tax-shielded debt, though it also raises sensitivity of equity returns to cash-flow swings. The stated bounds keep gearing within typical European practice.

How these inputs work together. The **Weibull parameters** fix the energy denominator for LCOE after the loss factor; the **feed-in tariff** applied to those MWh sets revenue for ROE; and the trio of **interest rate, equity share, and tax** defines the discount rate that weights all future costs and energy in present-value terms. **CAPEX/MW** dominates early-life costs, while **OPEX/MW-year** shapes the operating-life burden; both scale linearly with 1 GW capacity. In combination, these inputs position the Portugal case for outcomes similar in structure to Italy and the UK: LCOE will be most sensitive to the site-specific wind regime (k–c), the price of capital (coupon, equity share, tax), and the level of OPEX, with scale amplifying the impact of any adjustment. Before running scenarios, replace the indicative macro values with **LSEG-sourced** baselines and the indicative k–c with **NEWA** hub-height values for the chosen grid cell to ensure consistency and comparability across MARINEWIND labs.

Macroeconomic data - Portugal				
	Initial value	**Lower bound**	**Upper bound**	**Distribution density**
Inflation rate	3.4%	0%	10%	Truncated normal distribution
Interest rate on debt	7.5%	0%	14%	Truncated normal distribution
Feed in Tarif	188			
Tax rate	21%			
Capacity factor				
Weibull Shape factor	1.8			Weibull partial distribution function
Weibull scale factor	9.20			Weibull partial distribution function
Number of	64			

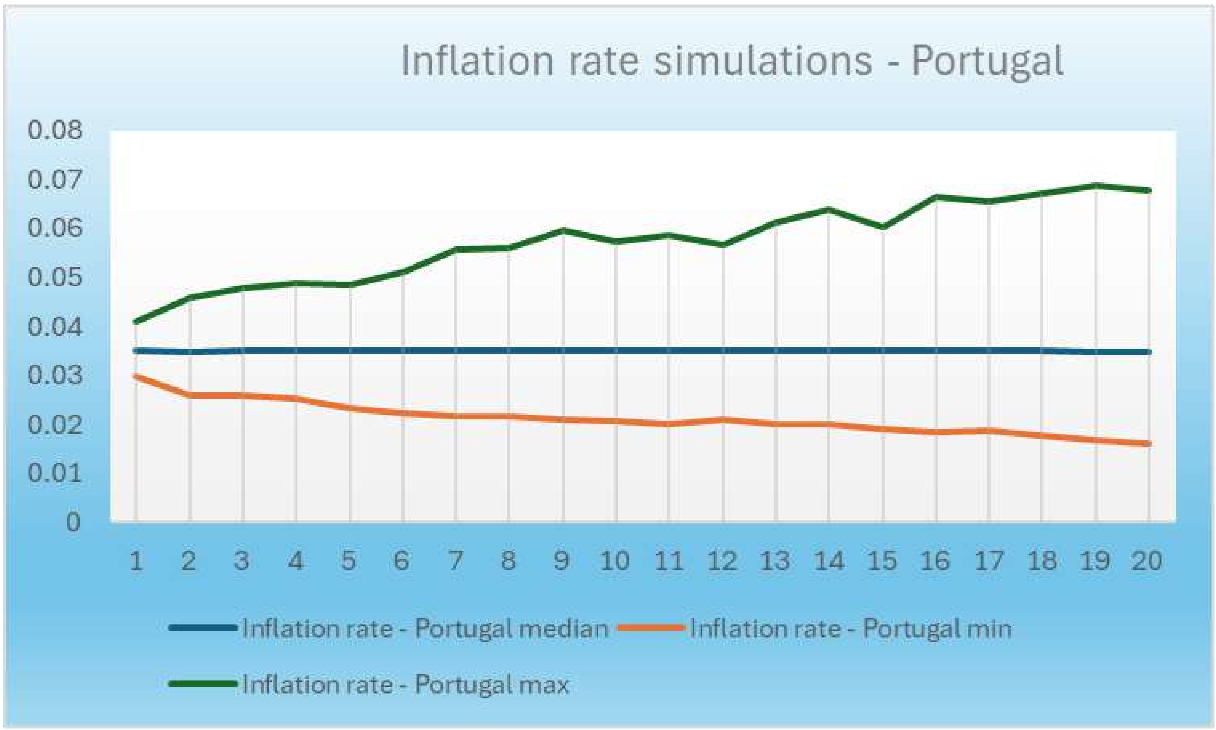
turbines				
Annual production loss	0.064%			
Site specific data				
Capacity of the Farm	1000 mw			
Operational years of the farm	20			
CAPEX/mw	EUR 4,000,000			
OPEX	EUR 158,000	EUR 60,000	EUR 190,000	Truncated normal distribution
Equity share	30%	10%	40%	Random Beta Distribution

3.3.2 Empirical findings

3.3.2.1 Macroeconomic variables simulation results

3.3.2.1.1 Inflation rate

The inflation path is stable around **~3.5%** throughout, with a gradual widening of the min–max envelope from **2.99–4.09%** in Year 1 to **1.63–6.77%** by Year 20. This keeps real/nominal conversions predictable on average, while acknowledging late-life tail outcomes. In the cash-flow, inflation interacts with the nominal coupon to shape the real cost of debt (and thus WACC) and, where indexation applies, the nominal drift of OPEX and revenues that influences ROE and, via discounting, LCOE.

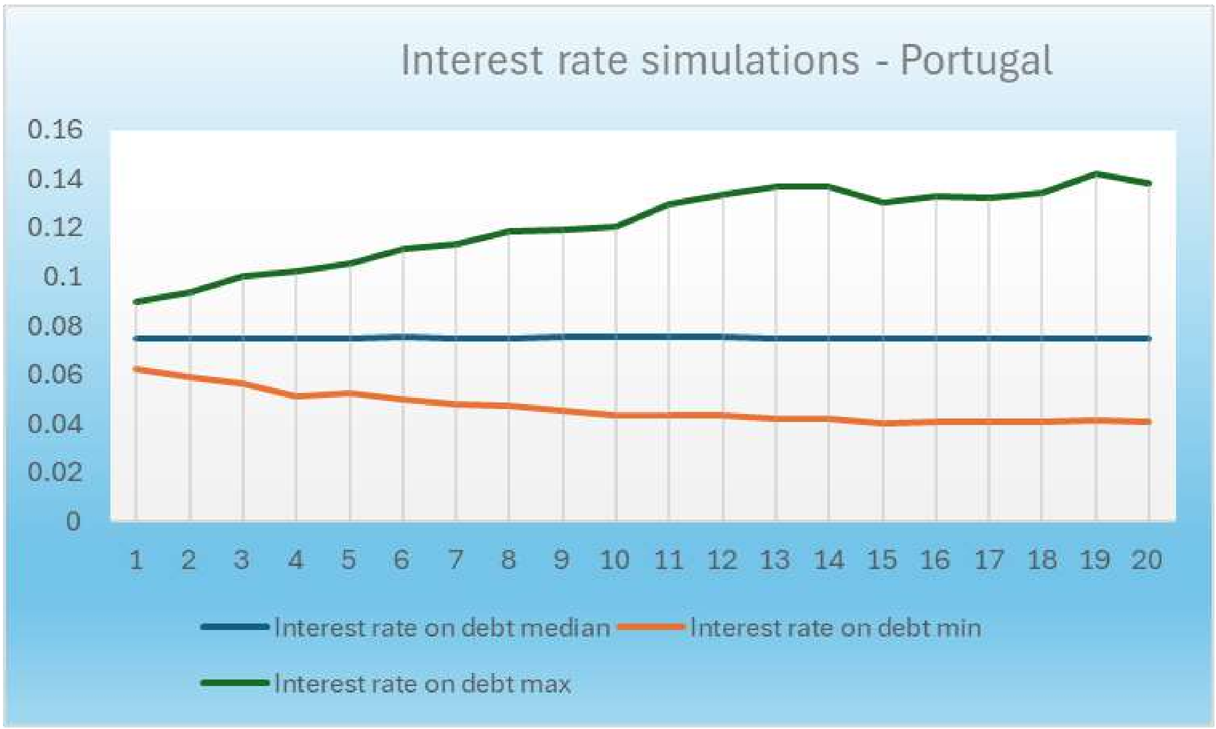


Inflation rate - Portugal			
Year	median	min	max
1	3.49402	2.99	4.09
2	3.49273	2.61	4.58
3	3.49458	2.58	4.78
4	3.51082	2.54	4.87
5	3.51156	2.33	4.86
6	3.52081	2.25	5.1

7	3.51679	2.17	5.58
8	3.51527	2.18	5.61
9	3.5107	2.11	5.97
10	3.50803	2.08	5.74
11	3.50054	2.02	5.87
12	3.49491	2.12	5.65
13	3.49968	2.01	6.13
14	3.50296	2	6.37
15	3.49378	1.92	6.01
16	3.49672	1.83	6.64
17	3.50095	1.88	6.55
18	3.49647	1.79	6.71
19	3.49026	1.67	6.86
20	3.49169	1.63	6.77

3.3.2.1.2 Interest rate on debt

Average borrowing costs remain close to **~7.5%**, with modest drift and expanding tails over time (late-life upper bounds into the **~13–14%** range; lower bounds near **~4%**). Because debt typically carries the largest weight in the capital stack, this variable materially affects the after-tax cost of debt and therefore WACC. Costlier years tighten equity margins and elevate WACC—conditions that push LCOE upward; more benign rate years do the reverse.



	Interest rate on debt - Portugal		
Year	**median**	**min**	**max**
1	7.49631	6.25	8.95
2	7.49574	5.9	9.34
3	7.50049	5.63	10.02
4	7.50066	5.1	10.21
5	7.50291	5.28	10.55

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6	7.51623	5.02	11.14
7	7.50489	4.82	11.35
8	7.50204	4.73	11.85
9	7.52225	4.51	11.93
10	7.53061	4.35	12.07
11	7.51478	4.36	12.98
12	7.51767	4.34	13.35
13	7.49634	4.22	13.68
14	7.49464	4.21	13.69
15	7.48411	4.04	13.06
16	7.48364	4.09	13.32
17	7.49133	4.11	13.25
18	7.48199	4.07	13.42
19	7.49832	4.13	14.22
20	7.49346	4.1	13.84

3.3.2.1.3 Equity fraction

The median equity share declines from **~29.9%** (Year 1) to **~23.7%** (Year 20) within the **10–40%** bounds. This migration toward higher leverage increases the weight of cheaper, tax-shielded debt and is a central driver of the observed decline in WACC. A thinner equity base amplifies percentage movements in ROE for a given cash-flow swing. For LCOE, leverage-induced WACC relief lowers the present-value burden of future costs and helps temper the impact of performance ageing on unit costs.

	Equity fraction - Portugal		
Year	median	min	max
1	29.92789	12.86	40
2	29.25657	11.46	40
3	28.95817	10	40
4	28.56103	10	40
5	28.16748	10	40
6	27.78615	10	40
7	27.38625	10	40
8	27.04427	10	40
9	26.43825	10	40
10	25.99214	10	40
11	25.91494	10	40

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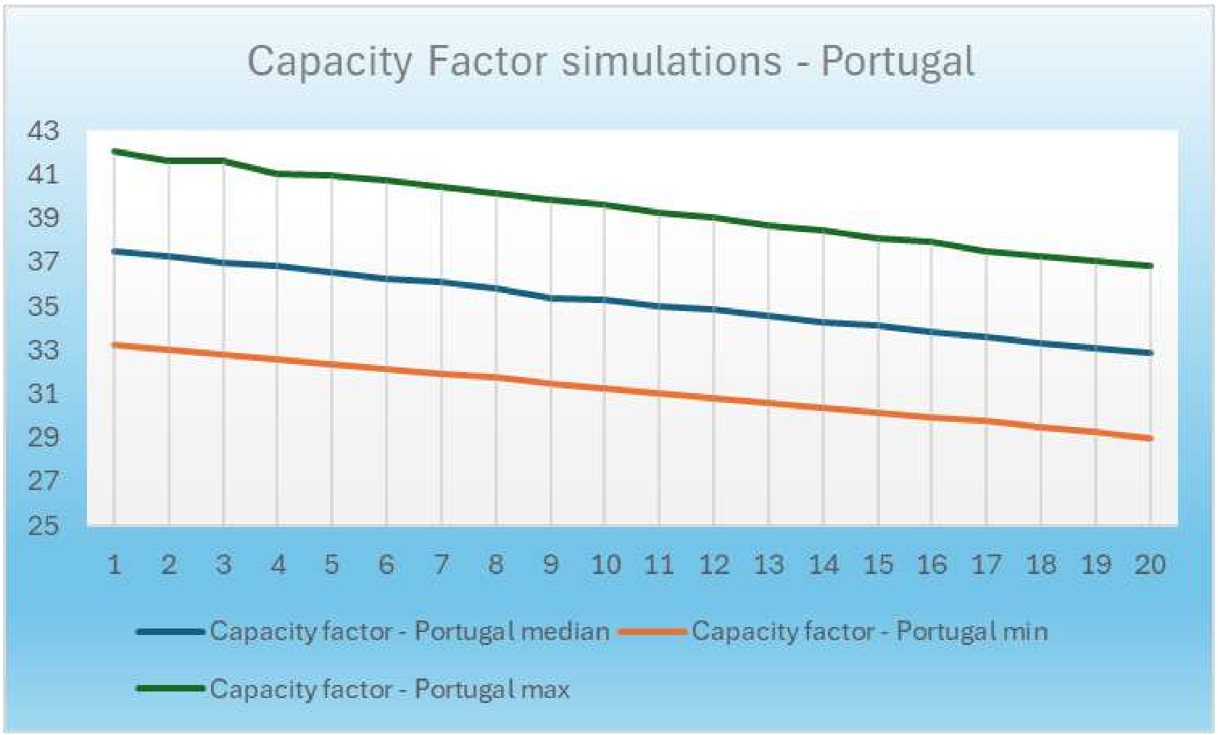
12	25.59711	10	40
13	25.35317	10	40
14	24.94765	10	40
15	24.68064	10	40
16	24.32446	10	40
17	24.05267	10	40
18	23.88495	10	40
19	23.52101	10	40
20	23.65816	10	40

3.3.2.2 Capacity factor

median CF starts near **37.5%** and declines smoothly to **~32.8%** by Year 20; minima and maxima follow similar downward paths (e.g., maxima from **~42.1%** to **~36.8%**). With many costs independent of output, this erosion spreads fixed and quasi-fixed costs over fewer MWh, placing upward pressure on LCOE in later years. Annual dispersion is contained, indicating that variability around the median remains moderate; the concurrent decline in WACC partly offsets the CF effect in the lifetime metric.



Capacity factor - Portugal			
Year	median	min	max
1	37.52625	33.25	42.05
2	37.30602	33.01	41.63
3	36.98823	32.83	41.6
4	36.81381	32.57	41.02
5	36.54779	32.34	40.93
6	36.236	32.16	40.76

7	36.09584	31.93	40.47
8	35.81237	31.76	40.16
9	35.40818	31.46	39.85
10	35.32619	31.29	39.63
11	35.00909	31.01	39.3
12	34.84771	30.83	39.07
13	34.55303	30.59	38.67
14	34.29793	30.35	38.49
15	34.12853	30.14	38.11
16	33.83135	29.9	37.94
17	33.57233	29.77	37.48
18	33.32063	29.51	37.27
19	33.12464	29.24	37.09
20	32.84387	29.01	36.81

3.3.2.3 OPEX

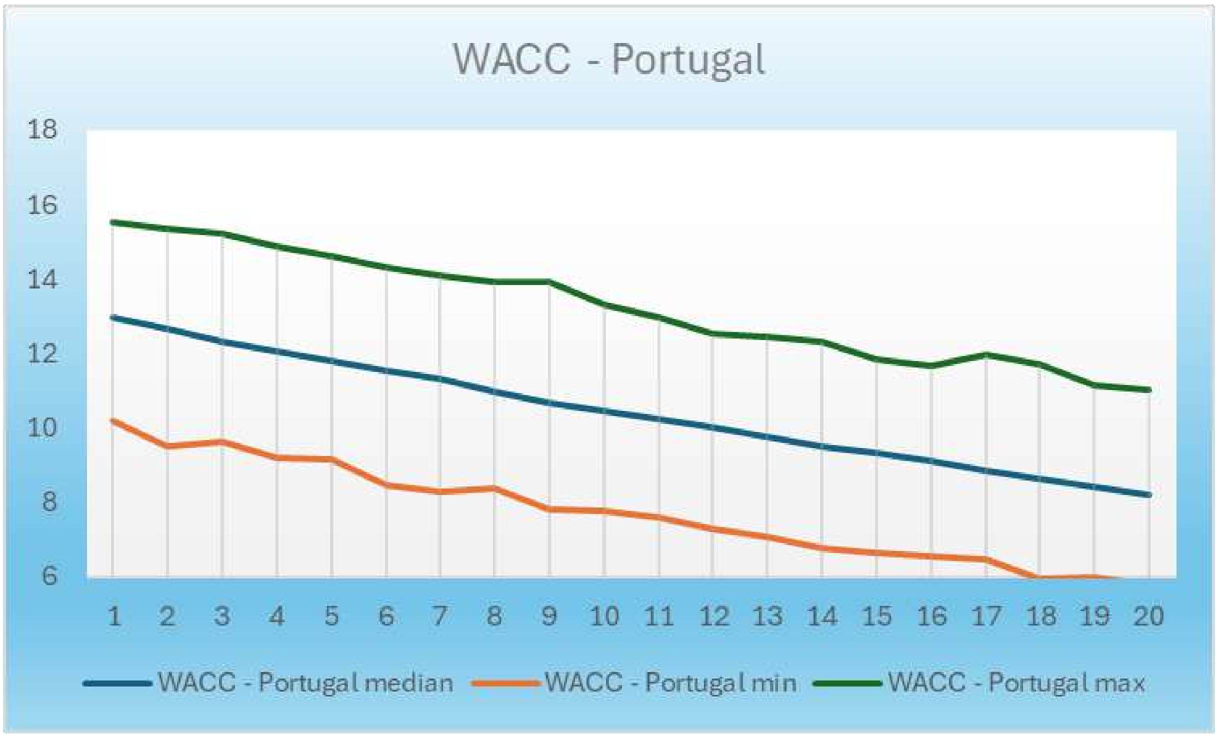
Per-MW OPEX hovers in a tight band around **€143–146k/MW-yr**, with bounds consistently near **€114k–€174k/MW-yr** across the horizon. Given the 1 GW scale, this stability is important: OPEX recurs annually and materially shapes the present-value cost numerator of LCOE. The bounded interval limits extreme outcomes. Years that combine lower CF with upper-band OPEX are most demanding for equity cash flows (lower ROE) and tend to nudge LCOE toward the top of its range.

OPEX - Portugal			
Year	median	min	max
1	143002.2	114075.4	173959.2
2	142886.8	114045.7	173994.3
3	144003.4	114013	173927.9
4	144464.6	114072.5	173974
5	144527	114063.7	173769.5
6	143624.3	114007	173973.3
7	143498.3	114008.9	173928.2
8	144936.6	114012.6	173866.7
9	144692.4	114044.8	173976.1
10	145618.6	114093.7	173895.7
11	143659.9	114087.1	173821.5
12	144384.6	114111.6	173941.2

13	143901	114139.4	173937
14	144144.9	114080.3	173898.2
15	143705.1	114095.6	173995.5
16	143230.8	114101.7	173948.7
17	143088.5	114129	173707.2
18	143025.7	114025.5	173918.2
19	143409.3	114036	173992.8
20	143828.6	114051.4	173928.3

3.3.2.4 WACC

The discount rate follows a **clear downward trajectory**, falling from **~12.95%** in Year 1 to **~8.20%** by Year 20; tails narrow as the asset matures (late-life minima **~5.8%**, maxima **~11.0%**). This reflects steady coupons on average, increasing debt weight, and a lower operating-risk profile post-commissioning. Lower WACC reduces the PV of long-dated costs and assigns greater value to later-life MWh, directly **reducing LCOE** and mitigating part of the upward pressure arising from CF decline.

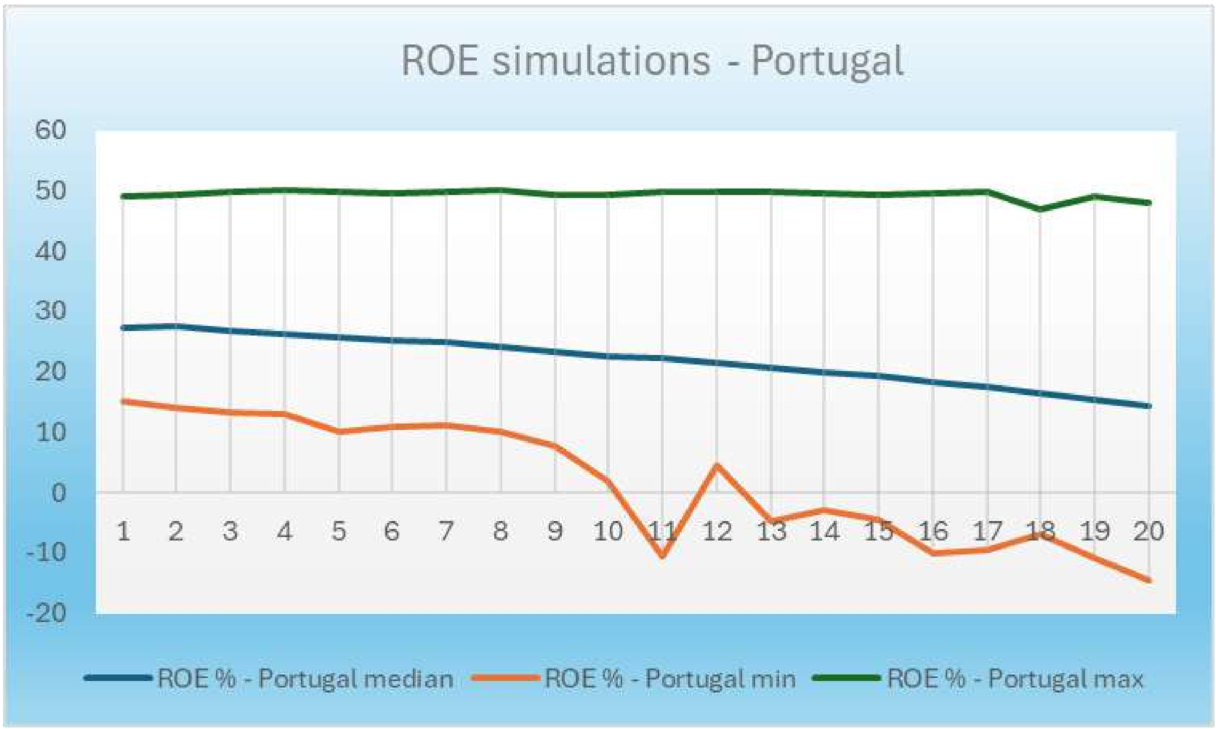


WACC - Portugal			
Year	median	min	max
1	12.94855	10.19	15.53
2	12.67066	9.49	15.37
3	12.33265	9.63	15.21
4	12.07759	9.19	14.88
5	11.79681	9.14	14.61
6	11.53074	8.48	14.32

7	11.31218	8.28	14.09
8	10.99604	8.39	13.92
9	10.67319	7.83	13.92
10	10.45523	7.77	13.33
11	10.24389	7.61	12.95
12	10.01336	7.31	12.52
13	9.77295	7.09	12.44
14	9.52262	6.79	12.31
15	9.33244	6.65	11.86
16	9.09526	6.54	11.66
17	8.86639	6.48	11.99
18	8.64603	5.97	11.73
19	8.42821	5.98	11.14
20	8.20113	5.76	11.04

3.3.2.5 ROE

median ROE starts high (**~27.2%**) and trends down to **~14.3%** by Year 20, with widening dispersion and negative annual values appearing in a subset of mid-to-late-life scenarios. The pattern aligns with gradually weaker output (lower CF), steady OPEX, and intermittent higher-rate years increasing debt service. Although ROE is not an input to the LCOE identity, adjustments made in response to ROE compression—such as refinancing or modest leverage changes—feed through WACC and consequently affect LCOE.



ROE % - Portugal			
Year	median	min	max
1	27.24165	15.18	48.91
2	27.47994	13.99	49.38
3	26.76829	13.4	49.87
4	26.33461	12.9	49.98
5	25.77283	10.17	49.84

6	25.23701	11.02	49.62
7	24.84654	11.25	49.85
8	24.09523	10.18	49.99
9	23.21263	7.81	49.23
10	22.65921	1.99	49.18
11	22.18174	-10.5	49.9
12	21.58395	4.49	49.77
13	20.73559	-4.65	49.74
14	19.82828	-2.99	49.65
15	19.2868	-4.35	49.36
16	18.37817	-10.08	49.55
17	17.48325	-9.54	49.81
18	16.42295	-6.83	47
19	15.52969	-10.76	48.96
20	14.25759	-14.62	47.99

3.3.2.6 LCOE analysis

The table reports the outcomes from the full MARINEWIND LCOE analysis and, for comparison, a fixed-charge ("simplified") benchmark. The **model LCOE** centres at **EUR 148.28/MWh**, with a **minimum of EUR 144.52/MWh** and a **maximum of EUR 152.62/MWh**. This is a **narrow band** (≈ EUR 8/MWh), indicating that under the assumed input ranges—macroeconomic paths, leverage, OPEX envelope, and the projected capacity-factor trajectory—the lifetime unit cost clusters tightly around the midpoint. The **simplified LCOE** is **EUR 146.32/MWh**, now **below** the model median. This gap suggests that a single fixed charge rate **understates** costs relative to the year-by-year treatment: the dynamic model explicitly carries the interaction of changing financing mix, coupons, and output ageing through discounting, which in this case lifts the central estimate above the fixed-rate proxy.

The **WACC** distribution has a **median of 10.34%** with bounds **7.77–13.39%**. A centre in the low-double-digits reflects substantial debt participation at coupons consistent with the assumed macro environment and a 20-year operating horizon. The span across the bounds captures credible financing states—from favourable pricing and stronger debt capacity at the low end to tighter conditions at the high end. Because WACC weights every future cost and MWh, values toward the lower end **reduce** the present-value burden of long-dated OPEX and **support** lower LCOE outcomes; higher values push the LCOE toward the top of the reported range.

The **ROE** distribution-**median 20.54%, 8.97–40.46%**—is wide and firmly positive, consistent with strong early-life margins at the assumed tariff, OPEX, and leverage. The breadth reflects sensitivity to combinations of energy output and borrowing costs: scenarios with modest coupons and upper-range generation push ROE into the high-teens/low-twenties and beyond; less favourable years compress it toward the lower bound. Although ROE is not an input to LCOE, equity-side adjustments taken to manage ROE (e.g., refinancing, calibrated leverage) feedback through WACC and can shift LCOE within its narrow band.

Overall, the Portugal case presents a **tight LCOE distribution just below EUR 150/MWh**, underpinned by financing terms centred around a ~10% WACC and equity returns that are attractive on average but still contingent on maintaining availability, OPEX discipline, and timely financing optimisation.

Model	Median	Minimum	Maximum
LCOE	EUR 175.33	EUR 166.79	EUR 191.99
simplified LCOE	EUR 173.10	EUR 173.10	EUR 173.10
WACC	7.34%	5.22%	9.34%
ROE	20.54%	8.97%	40.46%

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3.4 Spain

3.4.1 Data input

Below is an interpretation of the **Spain (Mediterranean) input table** for a planned 1 GW floating offshore wind farm. As with the UK and Italy cases, the focus is on what each entry does in the MARINEWIND LCOE analysis and how the inputs jointly shape LCOE, WACC, and ROE once the simulation is run. This data was obtained from the MARINEWIND survey.

Macroeconomic environment. The **inflation rate (3.20%)**, bounded **0–10%** with a **truncated-normal** law, sets the price index used to reconcile nominal and real terms and to apply any contract indexation. The **interest rate on debt (7.20%)**, likewise bounded **0–14%** under a truncated-normal density, provides the starting coupon for project borrowing. Together with the **corporate tax rate (25%)** and the equity share, these variables determine the after-tax cost of debt and therefore the discount rate applied to cash flows. The **feed-in tariff (€220/MWh)** anchors unit revenue applied to net energy. These entries define the financial backdrop for the Spanish case and can be updated to match LSEG/official series before running scenarios.

Wind resource and energy yield. Energy is generated from a **Weibull representation** of hub-height wind speeds rather than from a fixed capacity-factor guess. The **shape factor k=2.00** and **scale factor c=8.80** define the wind-speed frequency curve for the selected offshore cell. These parameters are passed through the reference turbine power curve (with ageing and gross-to-net adjustments) to compute annual net MWh. The explicit **annual production loss (0.064%)** is applied as a post-aggregation correction (availability/electrical). Because lifetime net MWh forms the LCOE denominator, accurate kkk–ccc values from the **New European Wind Atlas** at the exact site are important for robust results.

Site and technical configuration. A **1,000 MW** plant with an indicative **67 turbines** (≈15 MW class) fixes the physical scale for both energy and costs. The **operating life (20 years)** is the valuation horizon for discounting costs and energy. At this scale, even small changes in availability or losses translate into large absolute shifts in annual MWh and therefore in revenue and unit costs.

Costs and financing. CAPEX is specified as **€4.8 million/MW** and is scaled by capacity to obtain the total investment used at financial close, debt sizing, and capital-recovery calculations. **OPEX** is **€138,000/MW-year** with bounds **€60,000–€175,000/MW-year** (truncated-normal). In the analysis, a per-MW annual operating cost within this interval is applied and then scaled to the plant level. Because OPEX recurs every year, its level directly shapes the present-value cost ledger in LCOE; the explicit interval prevents implausible values from dominating outcomes. Given the 1 GW size, a €10 k/MW-year change in OPEX moves plant O&M by ~€10 million/year, so calibration of this range is consequential.

Capital structure. The **equity share** is set at **30%** with bounds **10–50%** and a **beta distribution** (appropriate for a proportion). This determines initial leverage and, together with the coupon and tax rate, yields the **weighted average cost of capital (WACC)** used to discount all future costs and energy. Higher leverage tends to reduce WACC by increasing the weight of tax-shielded debt, though it also raises the sensitivity of equity returns to operating variability.

How these inputs work together. The **Weibull parameters** determine the energy denominator for LCOE (after losses). The **feed-in tariff** applied to those MWh sets revenue for ROE. The trio of **interest rate, equity share, and tax** defines the price of capital (WACC), which weights every future cost and MWh in present-value terms. **CAPEX/MW** dominates the upfront cost burden; **OPEX/MW-year** governs the operating-life burden; both scale linearly with capacity. Relative to the Atlantic cases, the Mediterranean wind regime implied by the indicative kkk–ccc pair suggests a moderate capacity factor; this increases the importance of OPEX discipline and financing optimisation to keep LCOE competitive.

Units and consistency. All monetary figures are in **EUR**; tariff is **€/MWh**, CAPEX is **€/MW**, and OPEX is **€/MW-year**. The turbine rating assumed in the power-curve integration should match the implied turbine count for 1 GW. Using consistent hub height for k –c, power curve, and losses is essential to avoid bias in the energy estimate and, by extension, in LCOE, WACC, and ROE

Macroeconomic data - Spain				
	Initial value	**Lower bound**	**Upper bound**	**Distribution density**
Inflation rate	3.2%	0%	10%	Truncated normal distribution
Interest rate on debt	7.2%	0%	14%	Truncated normal distribution
Feed in Tarif	200			
Tax rate	25%			
Capacity factor				
Weibull Shape factor	2.00			Weibull partial distribution function
Weibull scale factor	9.58			Weibull partial distribution

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				function
Number of turbines	67			
Annual production loss	0.064%			
Site specific data				
Capacity of the Farm	500 mw			
Operational years of the farm	20			
CAPEX/mw	EUR 4,800,000			
OPEX	EUR 138,000	EUR 60,000	EUR 175,000	Truncated normal distribution
Equity share	25%	10%	40%	Random Beta Distribution

3.4.2 Empirical findings

3.4.2.1 Macroeconomic variables simulation results

3.4.2.1.1 Inflation rate

The inflation path is stable around **~3.5%** throughout, with a gradual widening of the min–max envelope from **2.99–4.09%** in Year 1 to **1.63–6.77%** by Year 20. This keeps real/nominal conversions predictable on average, while acknowledging late-life tail outcomes. In the cash-flow, inflation interacts with the nominal coupon to shape the real cost of debt (and thus WACC) and, where indexation applies, the nominal drift of OPEX and revenues that influences ROE and, via discounting, LCOE.

	Inflation rate - Spain		
Year	median	min	max
1	3.20654	2.67	3.73
2	3.21336	2.57	3.98
3	3.21299	2.44	4.13
4	3.21185	2.35	4.35
5	3.20872	2.14	4.29
6	3.21381	2.07	4.58

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7	3.21536	2.13	4.55
8	3.21327	2.06	5.04
9	3.21307	2.01	5.15
10	3.2102	2	5.29
11	3.21585	1.87	5.18
12	3.22363	1.78	5.71
13	3.22528	1.8	6.31
14	3.22741	1.76	6.49
15	3.23182	1.76	6.46
16	3.2267	1.67	5.95
17	3.22049	1.69	6.14
18	3.21837	1.71	6.28
19	3.21288	1.68	6.4
20	3.21724	1.65	6.39

3.4.2.1.2 Interest rate on debt

Average borrowing costs remain close to **~7.5%**, with modest drift and expanding tails over time (late-life upper bounds into the **~13–14%** range; lower bounds near **~4%**). Because debt typically carries the largest weight in the capital stack, this variable materially affects the after-tax cost of debt and therefore WACC. Costlier years tighten equity margins and elevate WACC—conditions that push LCOE upward; more benign rate years do the reverse.

	Interest rate on debt - Spain		
Year	median	min	max
1	7.20623	5.99	8.51
2	7.22069	5.78	8.97
3	7.22134	5.41	10.03
4	7.19562	4.93	10.23
5	7.19027	4.65	10.2

6	7.18859	4.42	10.75
7	7.2019	4.51	11.69
8	7.20332	4.31	12.56
9	7.17309	4.12	12.41
10	7.19354	4.21	13.05
11	7.21388	4.3	12.16
12	7.21105	4.28	12.36
13	7.21601	4.06	13.35
14	7.20271	4.07	12.98
15	7.20413	4.15	12.69
16	7.17673	4.01	13.65
17	7.15977	4.06	13.59
18	7.14978	4.08	14.6
19	7.13448	4.07	14.17
20	7.12516	4.02	14.05

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3.4.2.1.3 Equity fraction

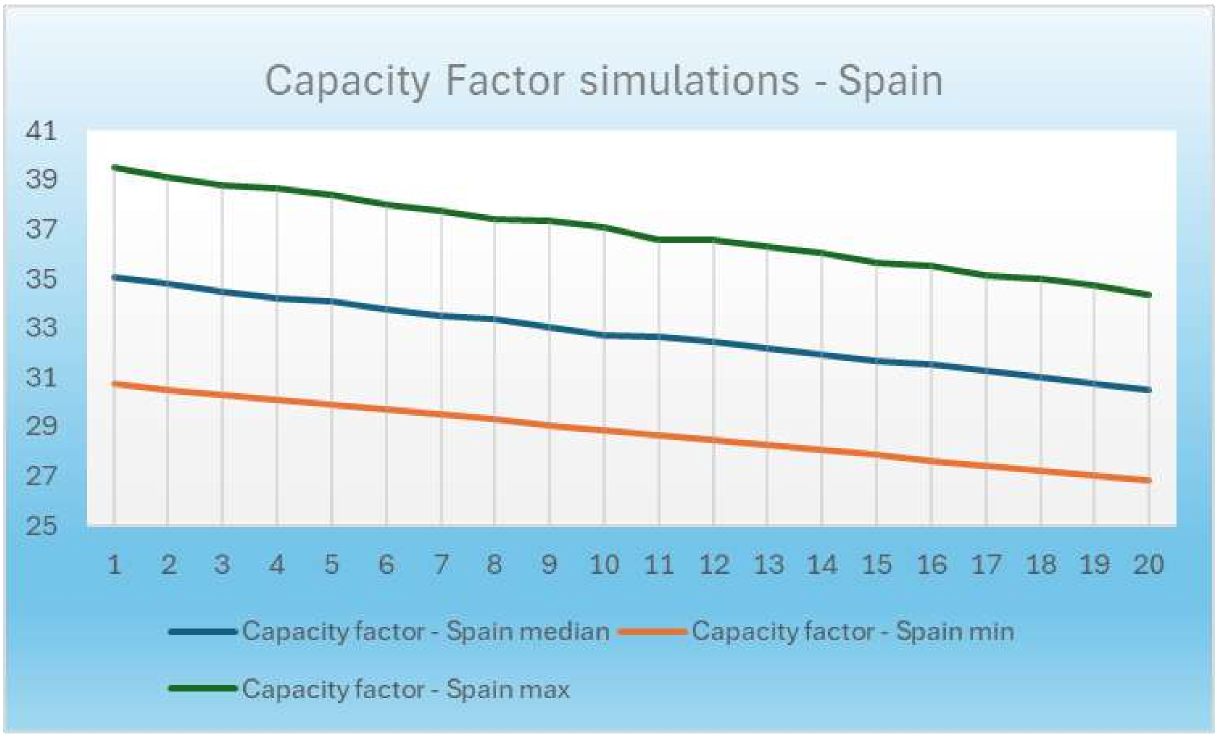
The median equity share declines from **~29.9%** (Year 1) to **~23.7%** (Year 20) within the **10–40%** bounds. This migration toward higher leverage increases the weight of cheaper, tax-shielded debt and is a central driver of the observed decline in WACC. A thinner equity base amplifies percentage movements in ROE for a given cash-flow swing. For LCOE, leverage-induced WACC relief lowers the present-value burden of future costs and helps temper the impact of performance ageing on unit costs.

	Equity fraction - Spain		
Year	**median**	**min**	**max**
1	24.75878	10	40
2	24.5701	10	40
3	24.71731	10	40
4	24.44447	10	40
5	24.27405	10	40
6	23.8121	10	40
7	23.63883	10	40
8	23.66591	10	40
9	23.78481	10	40
10	23.49455	10	40
11	23.42786	10	40

12	23.45762	10	40
13	23.28981	10	40
14	23.18909	10	40
15	23.28189	10	40
16	23.00633	10	40
17	23.01724	10	40
18	22.78592	10	40
19	22.97327	10	40
20	22.71926	10	40

3.4.2.2 Capacity factor

median CF starts near **37.5%** and declines smoothly to **~32.8%** by Year 20; minima and maxima follow similar downward paths. With many costs independent of output, this erosion spreads fixed and quasi-fixed costs over fewer MWh, placing upward pressure on LCOE in later years. Annual dispersion is contained, indicating that variability around the median remains moderate; the concurrent decline in WACC partly offsets the CF effect in the lifetime metric.



Capacity factor - Spain			
Year	median	min	max
1	35.0364	30.74	39.48
2	34.81773	30.52	39.11
3	34.45153	30.31	38.82
4	34.24738	30.12	38.69
5	34.10034	29.91	38.43
6	33.78282	29.7	37.98

7	33.49664	29.49	37.73
8	33.35691	29.3	37.44
9	33.06598	29.08	37.37
10	32.69881	28.89	37.1
11	32.6569	28.68	36.6
12	32.43191	28.48	36.58
13	32.17091	28.26	36.32
14	31.9501	28.06	36.06
15	31.65978	27.85	35.65
16	31.52113	27.64	35.53
17	31.27294	27.45	35.11
18	31.03877	27.24	35
19	30.74958	27.04	34.73
20	30.52112	26.83	34.36

3.4.2.3 OPEX

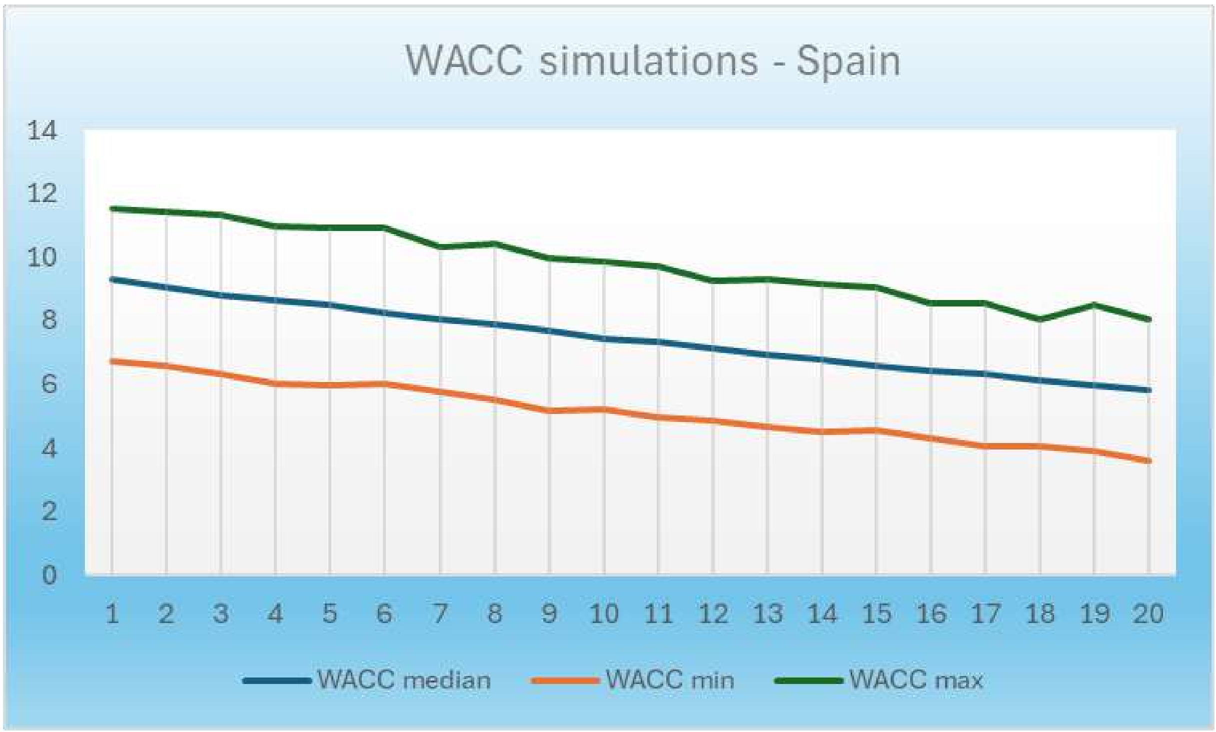
Per-MW OPEX hovers in a tight band around **€143–146k/MW-yr**, with bounds consistently near **€114k–€174k/MW-yr** across the horizon. Given the 1 GW scale, this stability is important: OPEX recurs annually and materially shapes the present-value cost numerator of LCOE. The bounded interval limits extreme outcomes. Years that combine lower CF with upper-band OPEX are most demanding for equity cash flows (lower ROE) and tend to nudge LCOE toward the top of its range.

OPEX - Spain			
Year	**median**	**min**	**max**
1	144182	114267.4	173954.9
2	145397.6	114193.1	173958.2
3	144879.5	114019.1	173851.9
4	144340.7	114017	173855
5	143177.4	114055	173897.3
6	143211.5	114025	173857.2
7	142600.1	114058.7	173946.9
8	143185.2	114137	173997.8
9	143179.3	114007.3	173932.4
10	143758.4	114003.1	173907.6
11	144187.1	114106.3	173862.1
12	144371.6	114037.8	173951.2

13	144779.6	114011.3	173961.5
14	144444.1	114207.6	173943.8
15	144792.6	114037.6	173922.1
16	144606.2	114030.8	173992.7
17	143316.2	114003	173962.2
18	143661.9	114037.6	173998.8
19	143172	114001.2	173945.1
20	142733.3	114004	173913.1

3.4.2.4 WACC

The discount rate follows a **clear downward trajectory**, falling from **~12.95%** in Year 1 to **~8.20%** by Year 20; tails narrow as the asset matures (late-life minima **~5.8%**, maxima **~11.0%**). This reflects steady coupons on average, increasing debt weight, and a lower operating-risk profile post-commissioning. Lower WACC reduces the PV of long-dated costs and assigns greater value to later-life MWh, directly **reducing LCOE** and mitigating part of the upward pressure arising from CF decline.

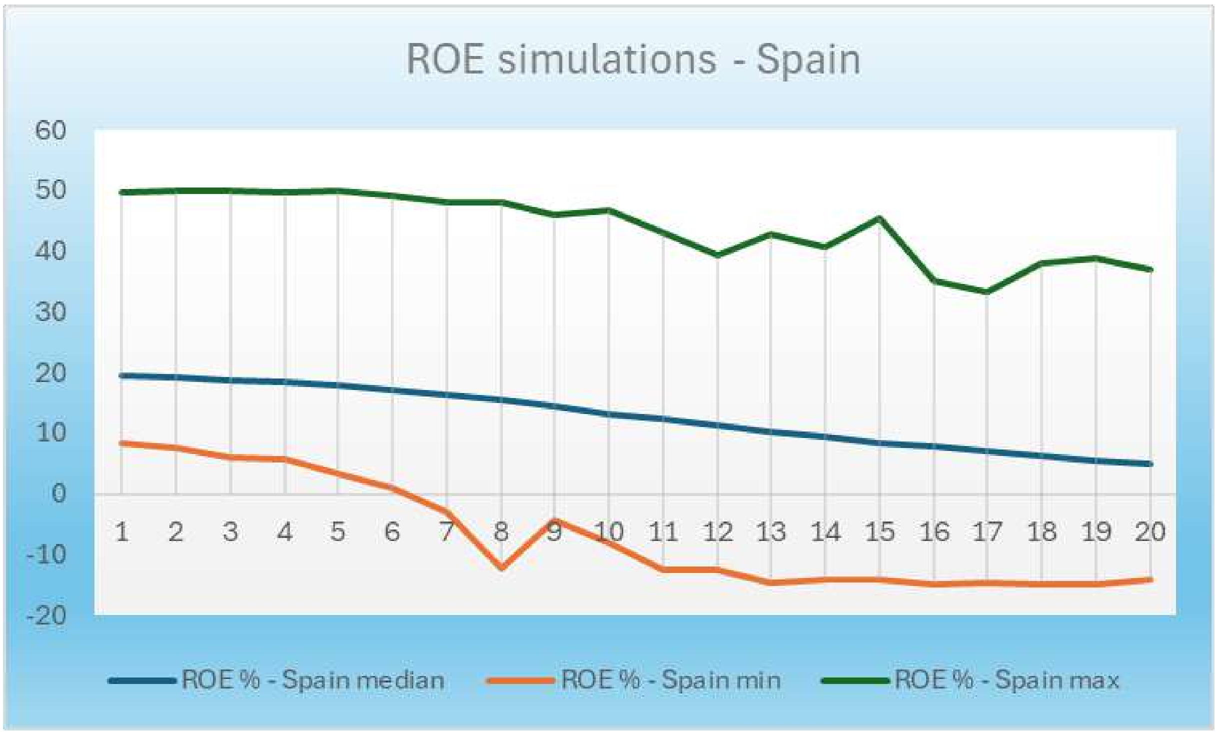


WACC - Spain			
Year	median	min	max
1	9.29194	6.73	11.56
2	9.0566	6.56	11.44
3	8.82688	6.35	11.34
4	8.64495	6.01	10.97
5	8.50188	5.99	10.92
6	8.26528	6	10.93

7	8.06719	5.79	10.33
8	7.89588	5.51	10.41
9	7.69741	5.18	9.97
10	7.44825	5.2	9.85
11	7.31698	4.94	9.71
12	7.14025	4.87	9.27
13	6.94081	4.68	9.29
14	6.77837	4.52	9.17
15	6.58319	4.55	9.04
16	6.43961	4.29	8.57
17	6.30221	4.05	8.57
18	6.12274	4.03	8.04
19	5.96234	3.88	8.5
20	5.81065	3.58	8.07

3.4.2.5 ROE

median ROE starts high (**~27.2%**) and trends down to **~14.3%** by Year 20, with widening dispersion and negative annual values appearing in a subset of mid-to-late-life scenarios. The pattern aligns with gradually weaker output (lower CF), steady OPEX, and intermittent higher-rate years increasing debt service. Although ROE is not an input to the LCOE identity, adjustments made in response to ROE compression—such as refinancing or modest leverage changes—feed through WACC and consequently affect LCOE.



ROE % - Spain			
Year	median	min	max
1	19.45151	8.42	49.57
2	19.32823	7.56	49.84
3	18.66829	6	49.92
4	18.34998	5.61	49.57
5	17.92613	3.35	49.9

6	17.23656	0.85	49.14
7	16.35774	-2.96	48.16
8	15.48084	-12.27	48.02
9	14.40468	-4.39	45.97
10	13.21527	-8	46.68
11	12.31231	-12.46	42.98
12	11.24793	-12.54	39.23
13	10.26158	-14.73	42.7
14	9.39922	-14.14	40.63
15	8.34367	-14.24	45.42
16	7.8075	-14.94	35.14
17	7.03386	-14.7	33.39
18	6.39286	-14.96	38
19	5.49656	-14.9	38.92
20	4.8628	-14.25	37.1

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3.4.2.6 LCOE analysis

The table consolidates the headline outcomes from the MARINEWIND LCOE model and, for comparison, a fixed-charge “simplified” benchmark. The **model LCOE** centres at **EUR 144.94/MWh**, spanning **EUR 140.94–152.44/MWh**. This is a **narrow band** (≈ EUR 11.5/MWh), indicating that with the assumed input ranges—macro variables, leverage, OPEX bounds, and the projected capacity-factor trajectory—the lifetime unit cost clusters tightly around the midpoint. The **simplified LCOE** of **EUR 147.60/MWh** sits **above** the model median. That gap is expected where a fixed charge rate cannot reflect year-by-year movements in the financing mix, borrowing costs, and ageing-related output changes that the full model carries through discounting; here, the dynamic treatment yields a slightly **lower** central cost.

The **WACC** distribution has a **median of 7.4%** with bounds **5.35–9.69%**. A centre in the mid-7% range is consistent with significant debt participation at moderate coupons over a 20-year horizon. The span across the bounds captures credible financing states—from favourable pricing and stronger debt capacity at the low end to tighter conditions at the high end. Because WACC weights every future cost and MWh, values toward the lower end **reduce** the present-value burden of long-dated OPEX and **support** lower LCOE outcomes; higher values tilt the LCOE toward the top of the reported band.

The **ROE** distribution—**median 11.69%**, **0.44–28.65%**—is broader and reflects the residual nature of equity cash flows once debt service and OPEX are met. Outcomes near the top of the range align with combinations of stronger-than-median energy and more favourable borrowing terms; outcomes near the bottom coincide with weaker production and/or higher coupons. The **positive lifetime minimum** (0.44%) indicates that, across years in the scenarios considered, aggregate equity performance remains preserved, albeit with sensitivity to downside combinations.

Taken together, the Spanish (Mediterranean) case presents a **tightly concentrated LCOE just under EUR 145/MWh**, underpinned by financing terms centred around a ~7.5% WACC and equity returns that are modest but serviceable on average. The levers most likely to move results within the reported bands are (i) preserving availability and controlling electrical/wake losses to protect the capacity factor, (ii) maintaining OPEX discipline within the specified envelope, and (iii) timing financing actions (e.g., post-COD refinancing) to keep WACC toward the lower end of its range. In combination, these factors explain why the dynamic model outperforms the simplified measure and why the LCOE distribution remains narrow for the planned Mediterranean site.

Model	Median	Minimum	Maximum
LCOE	EUR 190.01	EUR 180.33	EUR 209.16

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simplified LCOE	EUR 202.87	EUR 202.87	EUR 202.87
WACC	7.4%	5.35%	9.69%
ROE	11.69%	0.44%	28.65%

4. Conclusions

This deliverable establishes a coherent probabilistic framework for evaluating floating offshore wind economics across heterogeneous European contexts. Three design choices underpin its usefulness. First, the energy denominator of LCOE is generated from Weibull parameters and a reference power curve rather than imposed as a fixed CF; this preserves physical meaning and lets resource uncertainty express itself in outcomes. Second, the cost of capital is allowed to vary year-by-year with macro conditions, capital structure, and taxation; this resolves a key limitation of static discounting and aligns the timing of risk with cash-flow valuation. Third, OPEX is simulated within bounded distributions and scaled to plant size, reflecting both industry dispersion and strong lifetime influence on LCOE. Together, these choices produce distributions—not just point estimates—for LCOE, WACC, ROE, and CF.

Across pilots, results share common patterns. LCOE distributions are reasonably tight, indicating that plausible ranges for macro variables, OPEX, and energy yield translate into concentrated lifetime unit costs. The decline in CF due to ageing increases unit costs late in life, but this is partially offset by a downward drift in WACC as operations de-risk and financing improves. The dynamic model often departs from the simplified fixed-charge result, especially where leverage and coupons shift materially through time—evidence that path-dependent discounting matters for capital-intensive assets.

Country applications confirm the framework's portability and diagnostic value. In the UK reference case, median WACC near the high-single-digits and early-life ROE strength coexist with an LCOE centered around £195/MWh. The Italian 1 GW case shows a mid-single-digit WACC and a higher central LCOE driven by the assumed tariff/cost balance and a 20-year horizon. Portugal's Atlantic case delivers LCOE just below €150/MWh under a ~10% WACC center, while Spain's Mediterranean case concentrates near €145/MWh with a ~7.4% WACC. These differences are traceable to macro assumptions, OPEX envelopes, and Weibull resource parameters, illustrating the framework's ability to attribute variation to specific inputs and to identify practical levers—availability, loss control, OPEX discipline, and financing optimization.

The implementation choices also matter. A single-screen input design with explicit units and currency handling, plus variable-level "fix" toggles, reduces errors, accelerates peer review, and supports sensitivity studies without re-engineering the model. The export function enables external validation and tornado-style diagnostics, while the side-by-side reporting of model and simplified LCOE clarifies when a fixed-charge proxy is acceptable and when a dynamic treatment is necessary.

Looking forward, the same framework can be extended along three axes. First, **resource fidelity**: replacing indicative Weibull parameters with site-measured time series will sharpen CF distributions and narrow LCOE uncertainty. Second, **contract realism**: explicit indexation rules for tariff and OPEX can be encoded to reflect pass-throughs under different support schemes, refining ROE and WACC paths. Third, **portfolio analysis**: running correlated scenarios across multiple sites will quantify diversification effects on system-level cost and risk. These extensions are natural within the existing architecture and will enhance decision support for developers, financiers, and policymakers as FOWT deployment scales.

In closing, this deliverable provides (i) a documented, reproducible LCOE/WACC/ROE methodology that combines macro-finance with wind engineering; (ii) country-level applications with interpretable, narrow outcome bands; and (iii) a practical interface that encourages disciplined inputs and transparent outputs. The approach is sufficiently rigorous for investment-grade screening yet flexible enough for rapid sensitivity work, positioning MARINEWIND to support credible cost trajectories and financing strategies for floating offshore wind across European waters.

5. References

- Amlashi & Baniotopoulos (2024) – *Probabilistic LCOE for Floating Wind*: Monte Carlo methodology with random CAPEX, OPEX, and wind variability.
- Amlashi & Lotfizadeh (2025) – *Life Cycle & Probabilistic LCOE Analysis*: Finding that OPEX uncertainties strongly influence LCOE distribution.
- Park *et al.* (2021) – *Impact of Risk on LCOE*: Notes on discount rates used by BEIS, EIA, IRENA for LCOE and caution on using high risk-adjusted rates.
- Discover Energy (2024) – *Probabilistic LCOE Guidance*: Importance of wind resource (capacity factor) uncertainty and other parameters on LCOE outcomes.
- BEIS (UK) – *Electricity Generation Costs 2020*: Definition and steps for LCOE calculation.
- Frazer-Nash Consultancy (DESNZ, 2023) – *Floating Offshore Wind LCOE Review*: Overview of LCOE cost components and assumptions.

6. Appendix (A1)

Assumption 1[4]: The annual energy production E and the costs are considered constant over the years of the offshore wind farm, and the CAPEX is paid fully at year t=0 during the construction phase" we get

[4] Aldersey-Williams and Rubert (2019), Levelised cost of energy -A theoretical justification and critical assessment, Energy Policy Vol 124, Page 169-179. https://doi.org/10.1016/j.enpol.2018.10.004

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$$LCOE = \frac{\sum_{t=1}^{n} \frac{CAPEX_t + OPEX_t}{(1+WACC)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+WACC)^t}}$$

$$LCOE = \frac{\sum_{t=1}^{n} \frac{CAPEX_t}{(1+WACC)^t} + \sum_{t=1}^{n} \frac{OPEX_t}{(1+WACC)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+WACC)^t}}$$

If we assume annual energy production (E) and the costs (OPEX) to be constant, we get

$$LCOE = \frac{\sum_{t=1}^{n} \frac{CAPEX_t}{(1+WACC)^t} + OPEX * \sum_{t=1}^{n} \frac{1}{(1+WACC)^t}}{E * \sum_{t=1}^{n} \frac{1}{(1+WACC)^t}}$$

$$= \frac{\sum_{t=1}^{n} \frac{CAPEX_t}{(1+*WACC)^t}}{E * \sum_{t=1}^{n} \frac{1}{(1+WACC)^t}} + \frac{OPEX * \sum_{t=1}^{n} \frac{1}{(1+WACC)^t}}{E * \sum_{t=1}^{n} \frac{1}{(1+WACC)^t}}$$

by distributing $\sum_{t=1}^{n} \frac{1}{(1+WACC)^t}$ in $\frac{OPEX * \sum_{t=1}^{n} \frac{1}{(1+WACC)^t}}{E * \sum_{t=1}^{n} \frac{1}{(1+WACC)^t}}$, we get

$$LCOE = \frac{\sum_{t=1}^{n} \frac{CAPEX_t}{(1+WACC)^t}}{E_t * \sum_{t=1}^{n} \frac{1}{(1+WACC)^t}} + \frac{OPEX_t}{E_t} \quad (4)$$

Under the assumption that ***"the overnight capital costs are paid fully at year t=0 during the construction phase"*** we get:[5]

$$LCOE = \frac{\frac{CAPEX_0}{(1+WACC)^0}}{E * \sum_{t=1}^{n} \frac{1}{(1+WACC)^t}} + \frac{OPEX}{E} = \frac{CAPEX_0}{E * \sum_{t=1}^{n} \frac{1}{(1+WACC)^t}} + \frac{OPEX}{E} \quad (5)$$

By using summation of geometric sequence formula given by:[6]

$$S_n = \sum_{t}^{n} ar^t = a * \frac{(1 - r^n)}{1 - r}$$

Where ***a*** is the first term of the series (a = 1), ***r*** is the common ratio, n is the number of terms. So, by substituting $\boldsymbol{a} = \mathbf{1}$ and $\boldsymbol{r} = (\frac{\mathbf{1}}{\mathbf{1+WACC}})$, we get:

[5] Aldersey-Williams and Rubert (2019), Levelised cost of energy -A theoretical justification and critical assessment, Energy Policy Vol 124, Page 169-179. https://doi.org/10.1016/j.enpol.2018.10.004

[6] (Robert G. Mortimer, (2013), Mathematics for Physical Chemistry (Fourth Edition), Chapter 10, Elsevier, Page 119-128, ISBN 9780124158092, https://doi.org/10.1016/B978-0-12-415809-2.00010-0.

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$$\sum_{t}^{n} \frac{1}{(1+WACC)^t} = \frac{1-(\frac{1}{1+WACC})^n}{1-\frac{1}{1+WACC}}$$

Simplifying by multiplying both denominator and numerator by $(1+WACC)^n$

$$\sum_{t}^{n} \frac{1}{(1+WACC)^t} = \frac{(1+WACC)*(1-(\frac{1}{1+WACC})^n)}{(1+WACC*(1-\frac{1}{1+WACC})}$$

Simplify the numerator by using the distributive property of multiplication over subtraction:

$$\sum_{t}^{n} \frac{1}{(1+WACC)^t} = \frac{(1+WACC-(\frac{1}{1+WACC})^n \ * \ (1+WACC)^n}{(1+WACC)^n*(1-\frac{1}{1+WACC})}$$

Simplify the numerator by cancelling out the common factors in the second term, we get

$$\sum_{t}^{n} \frac{1}{(1+WACC)^t} = \frac{(1+WACC)^n-1}{(1+WACC)^n*(1-\frac{1}{1+WACC})}$$

Simplify the denominator by setting 1 in the second term as $\frac{1+WACC}{1+WACC}$, we get:

$$\sum_{t}^{n} \frac{1}{(1+WACC)^t} = \frac{(1+WACC)^n-1}{(1+WACC)^n*(\frac{1+WACC}{1+WACC}-\frac{1}{1+WACC})} = \frac{(1+WACC)^n-1}{(1+WACC)^n*(\frac{WACC}{1+WACC})}$$

$$\sum_{t}^{n} \frac{1}{(1+WACC)^t} = \frac{(1+WACC)^n-1}{WACC(1+WACC)^{n-1}}$$

Hence, by substituting $\sum_t^n \quad \frac{1}{(1+WACC)^t}$ in Eq[5], we get:

$$LCOE = \frac{CAPEX_0}{E \ * \sum_{t=1}^{n} \quad \frac{1}{(1+WACC)^t}} + \frac{OPEX}{E}$$

$$LCOE = \frac{CAPEX_0}{E * \frac{(1+WACC)^n-1}{WACC(1+WACC)^{n-1}}} + \frac{OPEX}{E} = \frac{CAPEX_0 * \frac{WACC(1+WACC)^{n-1}}{(1+WACC)^n-1}}{E} + \frac{OPEX}{E}$$

$$LCOE = \frac{CAPEX_0 * \frac{WACC(1+WACC)^{n-1}}{(1+WACC)^n-1} + OPEX}{E}$$

Assuming that the Capital Recovery Factor[7] (CRF) and the Capacity factor[8] are defined as follows:

$$CRF = \frac{WACC(1+WACC)^n}{(1+WACC)^n - 1}$$

$$CF = \frac{AEP}{(Hours\ in\ a\ day) * (days\ in\ year)\ * maximum\ possible\ output}$$

Where AEP is the Annual Energy Production of the offshore wind plant.

E = $\frac{AEP}{maximum\ possible\ output}$

$$CF = \frac{E}{(Hours\ in\ a\ day) * (days\ in\ year)}$$

E = $CF * (Hours\ in\ a\ day) * (days\ in\ year)$

$$Hours\ in\ a\ day = 24$$

$$days\ in\ year = 365$$

E = $CF * 24 * 365 = CF * 8760$

$LCOE \cong sLCOE = \frac{CAPEX_0 * CRF + OPEX}{8760 * CF}$ (6)

Levelized cost of energy by Annual Technology Baseline (ATB)

$$LCOE \cong sLCOE = \frac{CAPEX_0 * CRF + OPEX}{8760 * CF}$$

$CAPEX_0 * CRF + OPEX \cong (FCR * CAPEX) + OPEX$

$$LCOE = \frac{(FCR * CAPEX) + OPEX}{CF * 8760}$$

[7] National Renewable Energy Laboratory, 2018. US Department of Energy. Simple Levelized Cost of Energy (LCOE) Calculator Documentation. www.nrel.gov/analysis/tech-lcoe-documentation.html

[8] Ibrahim Dincer, Muhammad F. Ezzat, (2018), Geothermal Energy Production: Comprehensive Energy Systems, Elsevier, Pages 252-303, ISBN 9780128149256, https://doi.org/10.1016/B978-0-12-809597-3.00313-8.

Section 2 - Hybrid integration and flexibility in floating offshore wind: Co-location strategies for floating offshore wind

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Definition of terms

BFOW: Bottom Fixed Offshore Wind.

CAPEX: Capital Expenditure. Upfront payment of a technology.

CFD: Contract for difference.

FOW: Floating Offshore Wind.

GIS: Geographical Information System.

OPEX: Operation Expenditure. Ongoing predictable costs required to operate a technology.

NPV: Net Present Value.

WEC: Wave Energy Converter.

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EXECUTIVE SUMMARY

The *Hybrid integration and flexibility in floating offshore wind: Co-location strategies for floating offshore wind report* as part of the *MARINEWIND* project investigates the potential of co-locating floating offshore wind (FOW) with wave, tidal, and storage technologies to optimise energy generation and improve system flexibility. With ambitious decarbonisation targets (50 GW of offshore wind by 2030, with 5 GW FOW), the UK provides a strong case for exploring co-location to address variability, improve grid resilience, and ease curtailment.

While a focus on Italy is documented in Deliverable 3.2 Analysis of technological barriers and enablers, this document uses the UK as a case study, focusing on regions with overlapping renewable energy resources, to assess the co-location potential using geographical data for tidal, wind, wave, and solar resources.

The analysis results show that the Rockall Plateau, Celtic Sea, and Orkney Islands have great potential for co-location, supported by existing projects like MeyGen and the West of Orkney Windfarm. There is moderate co-location potential in smaller portions of the Rockall Plateau, near the English Channel, and the northeastern parts of Scotland, which can support smaller-scale projects.

While solar energy is excluded from the Orkney analysis due to lower viability and limited offshore potential, southern regions like Cornwall and the Celtic Sea show promise. The model incorporated an electrolyser, hydrogen and battery storage, FOW, tidal, and wave energy to evaluate the possibility of integration with local energy requirements.

Initial results showed that no renewable generation or battery storage was installed under reference cost assumptions, indicating that these technologies require a supportive pricing mechanism to be viable. Hydrogen was primarily produced by using electricity purchased from the wholesale market. Hydrogen storage allows for smoothing of the electrolyser operation and reduces cost by maximising electrolyser generation when the electricity price is low and limiting hydrogen generation during higher price periods.

To explore the conditions of technical viability, a series of sensitivities were run on several parameters, and the impact on resulting net present value, optimal installed capacities, and operational flows of energy were analysed.

Sensitivities on cost reductions showed that FOW is on the cusp of economic viability in the scenario tested. A 9% decrease in reference CAPEX allowed for it to become profitable, which is encouraging given that FOW costs are forecasted to decrease by 20-30% in the next decade. The results for wave and tidal technologies are more challenging, given that a significant 85% and 70% (respectively) cost reductions were required to attain profitability. This suggests that innovation is required to reduce their investment costs. Co-location also offers the potential of sharing some of the logistic costs. However, this was not investigated in the present report.

The above results were obtained by considering the wholesale market price for the sale of electricity. Sensitivities implementing Contract for Difference (CFD) remuneration mechanisms were run. The

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results showed that the current CFD price for FOW (from the 2024 allocation round 6) allowed profitability. When testing other technologies, the results showed that higher CFD prices were required for wave and tidal. More interestingly, the modelling results suggest that the CFD mechanisms tend to favour a single "winner," which may hinder the other benefits of co-locating generation technologies.

Cost sensitivities on storage technologies consistently showed hydrogen storage being installed and operated as a bridge between electrolyser generation and hydrogen demand while allowing the electrolyser to operate at times of lower electricity costs. Battery storage required a substantial cost reduction for the system to be viable.

Additional network constraints were included in the sensitivity analysis, which showed that highly constrained networks favour significantly different combinations of technologies. Battery storage and tidal generation were favoured under highly constrained networks, whereas FOW remained the preferred option under low-constraint scenarios. This suggests that the detail of constraint levels and arrangements found by network operators may significantly impact the ideal combinations of technologies for a given site.

Although one should be cautious when extrapolating the details of the quantitative results from this study, high-level insights can be drawn by looking at the sensitivity analysis from this report. Different routes may be explored to increase the economic viability of offshore technologies, and their combination should be considered carefully to avoid implementing counter-productive methods. Typically, the sharing of infrastructure costs and the CFD costing mechanism approaches lead to increased viability; however, the former supports the co-location of assets, whereas the latter may need single-generation sites as a more profitable option.

Further detailed policy work will be required to refine the understanding of such considerations and the combination of nationwide and site-level analysis necessary to understand the challenges at stake fully. Reforms to the CFD to enable co-located assets are currently being explored following the Government Consultation on co-located generation in 2024, with the potential introduction of hybrid metering.

1. INTRODUCTION

1.1. Background

This report concerns the project activities performed within the framework of Work Package 3 Financing, techno-economic analysis and survey, namely under Task 3.2 *Analysis of technological barriers and enablers of floating offshore wind*. Combining floating wind energy with other offshore renewables on the same platform (hybrid platform) and/or in the same area (co-location) can mitigate some of the barriers to offshore renewable deployment by decreasing the conflict with other activities and increasing acceptability. In addition, combining the production from renewables with different variability can increase the flexibility and the quality of the overall power supply and facilitate grid integration. Finally, sharing some infrastructures (such as ports, grid, etc.) can contribute to decreasing costs. The description of a case study located in Italy has been already reported in Deliverable D3.2,

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where the analysis of a co-located wind and wave farm (1GW+1GW) shows that an integrated system would be able to deliver almost all the electricity produced using the export cable designed of the stand-alone wind farm.

Building upon the results outlined in D3.2, the present document is a deep dive into the opportunity presented by co-locating FOW with generation and storage technologies in the UK.

The UK government has expedited its targets for the decarbonisation of the electricity network, aiming to have an almost completely decarbonised power system by 2030 at 95% zero carbon and less than 5% from unabated gas [1], with offshore wind positioned as a key contributor. The UK has set an ambitious target of 50 GW of offshore wind capacity by 2030, including up to 5 GW of FOW [2], the current installed offshore wind capacity amounts to 14.7 GW [3], of which only 80 MW is floating. Consequently, there is a clear need to accelerate the deployment rates of offshore wind to meet the Government's ambitions for the sector and Net Zero targets.

The UK benefits from having one of the highest offshore wind resources in Europe, if not globally, and has strategically placed itself as one of the global leaders in wind energy [4]. Currently, commercial-scale wind farms in the UK use Bottom Fixed Wind Turbines (BFWT), which are constrained to shallower waters, typically less than 60 meters deep) and are situated closer to the UK coastline. Instead, FOW turbines do not have these water depth limitations, enabling deployment in deep waters and offering an opportunity for the UK to capitalise on higher and more consistent wind speeds located further out to sea.

1.2. Motivations

Co-location of FOW generation with other generation technologies, such as floating solar, tidal stream and wave energy, can alleviate the variability of power output and thus increase revenues from FOW developments. Floating wind offers a significant opportunity for co-location with wave energy generation as the floating technology allows exploring areas with high wave resources previously inaccessible to BFWT. Wind and wave resources exhibit complementary behaviour, where strong winds generate high wave resources, with the peak of the latter occurring with a time delay. The time offset between peak wind and wave energy resources helps maintain consistent power generation. The co-location of wave energy converters (WEC) and FOW presents an opportunity to commercialise these nascent technologies by reducing operational and developmental costs. Previous research indicates that such projects can reduce the LCOE by 7% for wind and 40% for wave projects [5].

Likewise, the co-location of FOW with hydrogen storage offers a significant opportunity to stabilise the variable generation profile of offshore wind. Storage assets add flexibility and increase the system's resilience by storing electricity as hydrogen. One of the greatest challenges facing the offshore wind industry is integrating with and connecting to electricity networks to enable effective electricity transmission. Currently, the UK electricity network is unfit for significant growth in renewable generation assets due to constraints limiting electricity transmission across the UK regions, resulting in wind turbine curtailment and wasted electricity generation. To this end, hydrogen production facilities can enable more efficient use of FOW and reduce the strain on the grid infrastructure. Aside from

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power generation, hydrogen produced from electrolysis can be used in difficult-to-decarbonise sectors, such as heavy industry, offroad, and marine transport. This increases the penetration of FOW, allowing for the utilisation of energy generated from wind to decarbonise through electrification.

1.3. Objectives

- Determine the impact of co-locating FOW with other generation and storage technologies on the techno-economic viability of a FOW site.
- Identify the key drivers of the techno-economic performance of a FOW co-location site and quantify their influence.
- Understand the impact of including various technologies and combinations of technologies on the optimal operation and sizing of a co-location site.

2. SCENARIOS

This analysis uses the UK as a case study to explore how the combination of floating offshore wind (FOW), tidal, and wave technologies can maximise offshore renewable energy resources. The study examines how co-locating these energy technologies can enhance infrastructure efficiency, support decarbonisation efforts, and promote environmental sustainability while aligning with the UK's renewable energy goals and transition to Net Zero. Additionally, the study analyses how to best integrate various technologies in offshore areas by targeting areas where co-location is possible. The analysis evaluates wind, wave, tidal, and solar energy potential using Geographical Information System (GIS) data [6][7], with resource allocation performed using GIS shapefiles. The percentages in Table 1 shows how much of each resource is available in different areas, based on thresholds manually defined in ArcGIS to provide a clearer picture of their distribution and intensity.

Table 1: Resource Assessment Metrics and Classification Thresholds

Technology	Metric Description	Range		
		Low	Medium	High
Tidal	*Average Tidal Power Obtainable per Square Metre (W/m^2)*	0-3%	4-22%	≥23%
Wind	*Annual Mean Wind Power Density (W/m^2)*	6-38%	39-67%	≥68%
Wave	*Annual Mean Wave Power per metre of crest (W/m)*	0-30%	31-57%	≥58%
Solar	*Annualised Global Horizontal Irradiance ($kWh/m^2/year$)*	38-77%	78-85%	≥86%

The intervals showed in Table 1 were used in the following to compare potentials and evaluate the co-location opportunities across the UK's offshore regions.

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2.1. Calculation methodology for co-location potential

This analysis focused on identifying areas where FOW can be co-located with tidal and wave. Below is an overview of the approach and criteria used to define high, medium, and low co-location potential.

Framework for co-location potential

The co-location analysis assumed that FOW is the primary technology, with tidal, wave, and floating PV providing complementary contributions. The methodology considered:

- Geographical Overlap: Regions in which two or more technologies could potentially be deployed.
- Complementarity: Regions where different types of technology could be used to increase energy production.

Classification of co-location potential

The potential for co-location has been grouped into three classes:

- High Potential:
  - Regions where at least two technologies have high potential, one high and the other medium.
  - Some regions with strong wind and wave resources were also marked as high potential, especially where FOW development is already underway.
- Medium Potential:
  - Regions where two technologies have medium potential, and the third has low potential.
- Low Potential:
  - Regions where no technology exceeds medium potential, or one is high while the others are low.

Adjustments for floating photovoltaics (PV)

Although coastal solar potential was not included in the combined co-location analysis with wind, wave, and tidal, it was assessed separately. This approach highlighted areas where floating PV could complement other renewable technologies, particularly the southern parts of the UK, like the Celtic Sea.

Key Assumptions and Constraints

- Spatial Data Constraints: The analysis was limited by the availability of offshore-specific datasets, particularly for solar energy.
- Technology Priority: FOW was prioritised over tidal and wave because its deployment is a key focus of this project. The study looks at the barriers and enablers in making floating wind more viable, including its integration with other technologies.

2.2. Resource potential overview: tidal, wind, and wave

The map below (Figure 1) shows the potential for tidal, wind, and wave potential across the UK, categorised into high, medium, and low regions using the normalised thresholds outlined earlier.

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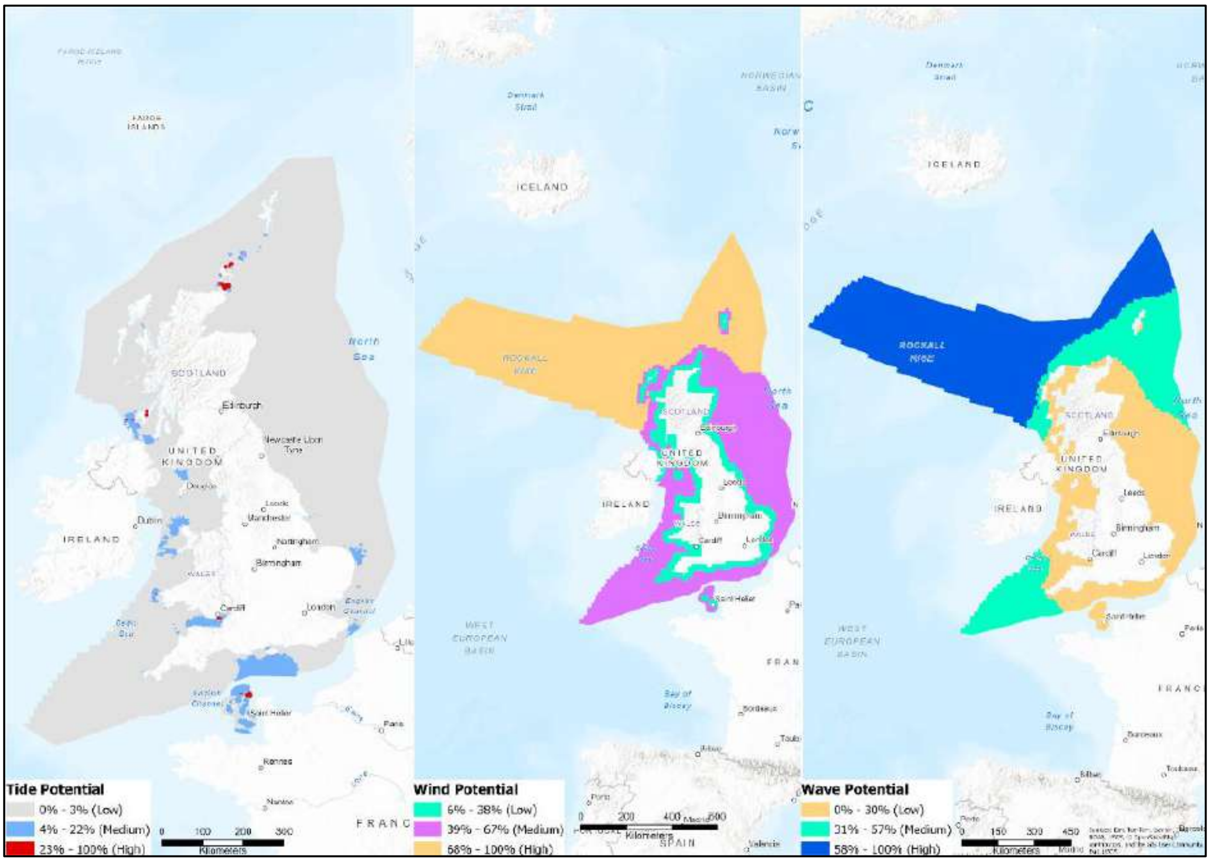

Figure 1: Tidal (left), Wind (centre), and Wave (right) Resource Potential Maps (Data Source: UK Renewables Atlas; processed using ArcGIS)

Tide potential: The different regions of the UK's offshore boundaries contrast the possibilities for developing tidal energy. The area with the highest potential is the area surrounding the Orkney Islands, particularly in the Pentland Firth, where the MeyGen Tidal Project is situated, which currently has an operational capacity of 6 MW, with plans to expand to 12 MW [8]. Regions of moderate tidal potential include Anglesey waters, which the Molaris Tidal Energy Scheme services, a 35 km² ideal zone with the potential to produce 240 MW of power [9], as well as parts of the Irish Sea, which includes the Milford Haven Demonstration Zone, with a capacity of 100MW [10][11]. On the contrary, the North Sea and some parts of the southern offshore regions have a lower tidal potential because of the existence of smaller tidal ranges (1-4 metres) and weaker tidal currents as opposed to sites like the Pentland Firth, where narrow channels increase tidal flow. [12].

Floating Wind potential: The Rockall Plateau, located to the West of Scotland in the North Atlantic Ocean, demonstrates substantial offshore wind energy resources, although legal and geopolitical constraints block optimal development [13]. The Orkney Islands, for instance, do have moderate

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offshore wind potential but also play an important role in the ScotWind leasing programme that aims to deploy nearly 30 GW of new generation capacity [14]. Furthermore, within the Orkney Islands, the West of Orkney wind farm, scheduled to commence generation in 2030, is a flagship project under this programme with over £4 billion in funding, including £140 million to strengthen the local supply chain. These projects will use floating wind technology to harness wind resources in deeper waters, demonstrating the potential of floating wind farms in the region.

The North Sea and Celtic Sea also have medium potential, with the Blue Gem Wind's Erebus Project, a floating wind farm that is planned to generate 100 MW of power [15]. The low potential is observed in northeastern and southern waters of the UK mainland due to relatively mild and moderate wind speeds compared to those farther offshore.

Wave potential: Like wind, the Rockall Plateau has a significant wave potential, but legal complications impede its development. In addition to having medium potential, the Orkney Islands are home to the European Marine Energy Centre (EMEC), a leader in global wave energy innovation [16]. For example, the WEDUSEA Wave Energy Demonstration, funded with €19.6 million, set to demonstrate a grid-connected 1MW OE35 floating wave energy converter at EMEC, is a notable project here, expected to begin in June 2025 [17][18]. The Celtic Sea also has medium potential, supported by the Pembrokeshire Demonstration Zone [19]. The low potential is observed in the North Sea and southern UK waters due to the limited wave exposure, shorter fetch distances, and lower wave heights and energy densities compared to the more exposed western regions [20].

In conclusion, the Orkney Islands remain a vital location for renewable energy, with high tidal and medium wind and wave potential, supported by projects like MeyGen and EMEC, which continue to drive innovation in the area.

2.3. Co-location potential map (high and medium)

This map in Figure 2 highlights the high and medium combined potential for co-locating floating wind, tidal and wave energy resources. Areas of low potential are omitted from this analysis since it focuses on the regions with maximum possibility for renewable energy development.

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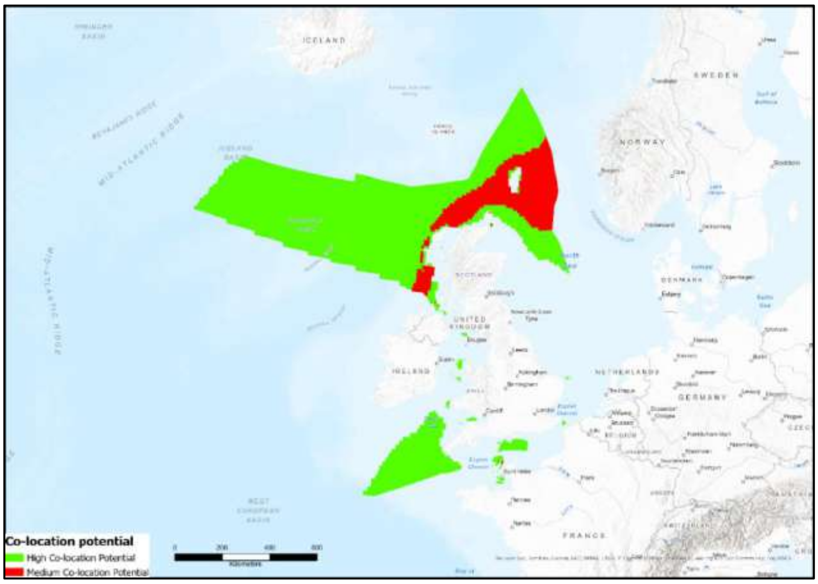

Figure 2: High and medium co-Location potential maps for tidal, wind, and wave energy (Data source: UK Renewables Atlas; processed using ArcGIS)

The map shows some parts of the UK that have potential offshore regions with an overlap of medium to high potential tidal, wind, and wave energy resources. High co-location potential is apparent in the North Sea, Celtic Sea, and the Rockall Plateau, where multiple technologies may be deployed together to harness renewable energy from different sources. Furthermore, the Orkney Islands area has strong tidal resources and moderate wind and wave potential, supported by existing activities like the MeyGen Tidal Project and the planned West of Orkney Windfarm under ScotWind. Furthermore, the Celtic Sea is classified as having high co-location potential because of the major FOW and wave energy projects like the 4.5 GW lease round by the Crown Estate [21] and the 100 MW Erebus Project [15], which supports the claim that the region is a focus for renewable energy development.

Moreover, co-location potential at a medium level is seen in the area northeast of Scotland, especially the vicinity of the Orkney Islands, where wind, tidal, and significant wave height resources overlap. In addition, smaller patches are also noted on the southern coast of England near the English Channel and in confined regions of the Rockall Plateau. These areas fall under medium co-location potential due to the resource availability of individual technologies, where no single resource exceeds the thresholds required for high potential classification.

2.4. Coastal solar resource potential

The map below (Figure 3) exhibits the coastal solar resource potential across the UK, divided into low, medium, and high categories based on solar irradiance.

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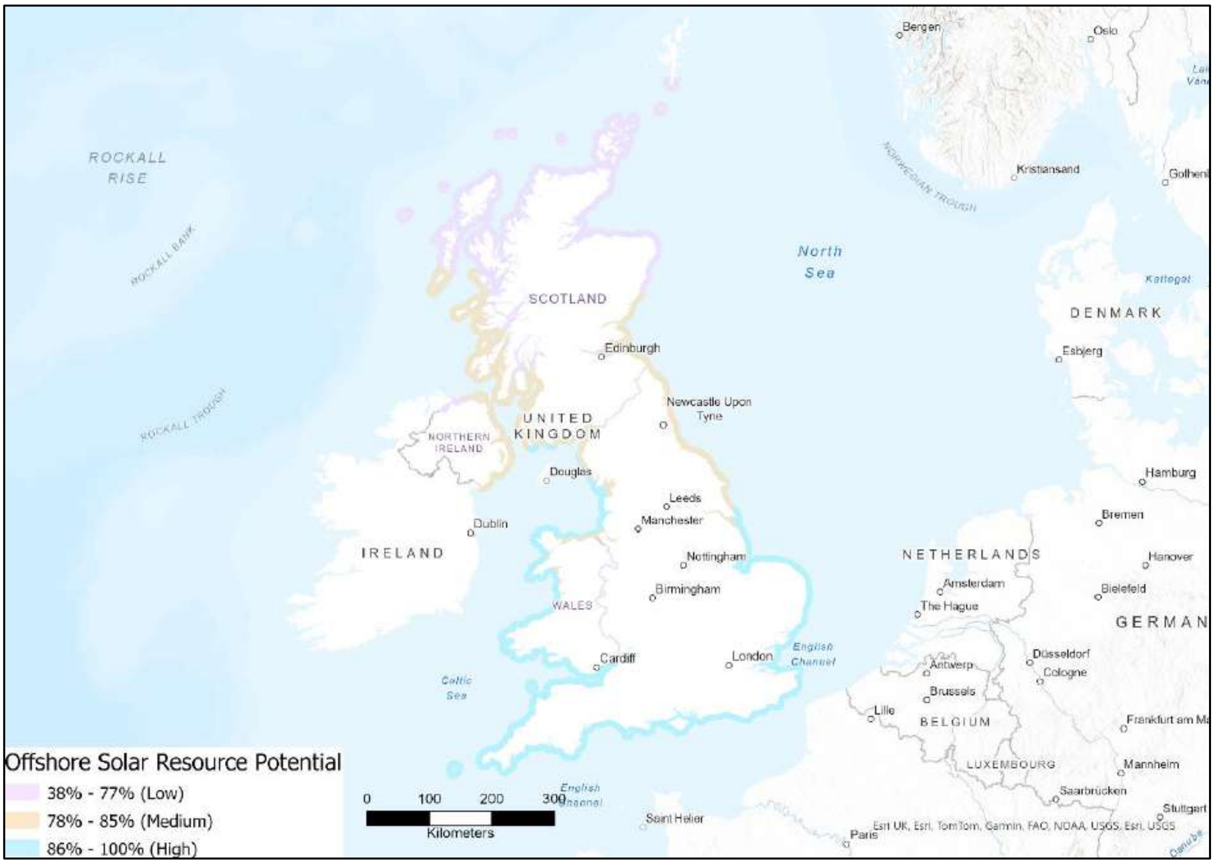

Figure 3: Coastal Solar resource potential across the UK (Data Source: Global Solar Atlas; processed using ArcGIS)

The solar potential is mostly concentrated towards the mainland and coastal areas, with limited potential farther offshore. Solar energy has not been included in the co-location model analysis for the Orkney scenario due to its lower resource potential compared to southern areas like Cornwall and the Celtic Sea. However, understanding how coastal solar potential is distributed helps explore how solar could complement other renewable technologies in wider energy strategies.

2.5. Co-Location Potential (Orkney Islands)

The Orkney Islands have been a central point for marine renewable energy development, with existing infrastructure supporting tidal, wind, and wave technologies. The map below (Figure 4) shows areas of high and medium co-location potential based on regions where medium to high potential for each resource overlap.

Areas with high co-location potential are primarily focused to the west and northeast of the islands, where tidal, wind, and wave resources overlap. The region to the south of Orkney is notable for having strong tidal energy and moderate amounts of wind and wave resources. It also contains projects like the MeyGen Tidal Project and is part of larger efforts to plan renewable energy, including ScotWind.

Potential areas with medium co-location potential can be found on the smaller regions of the north and southern coast, where two resources, wind and wave, usually overlap. These regions are most likely to have projects or pilot initiatives but would require considerable analysis to determine

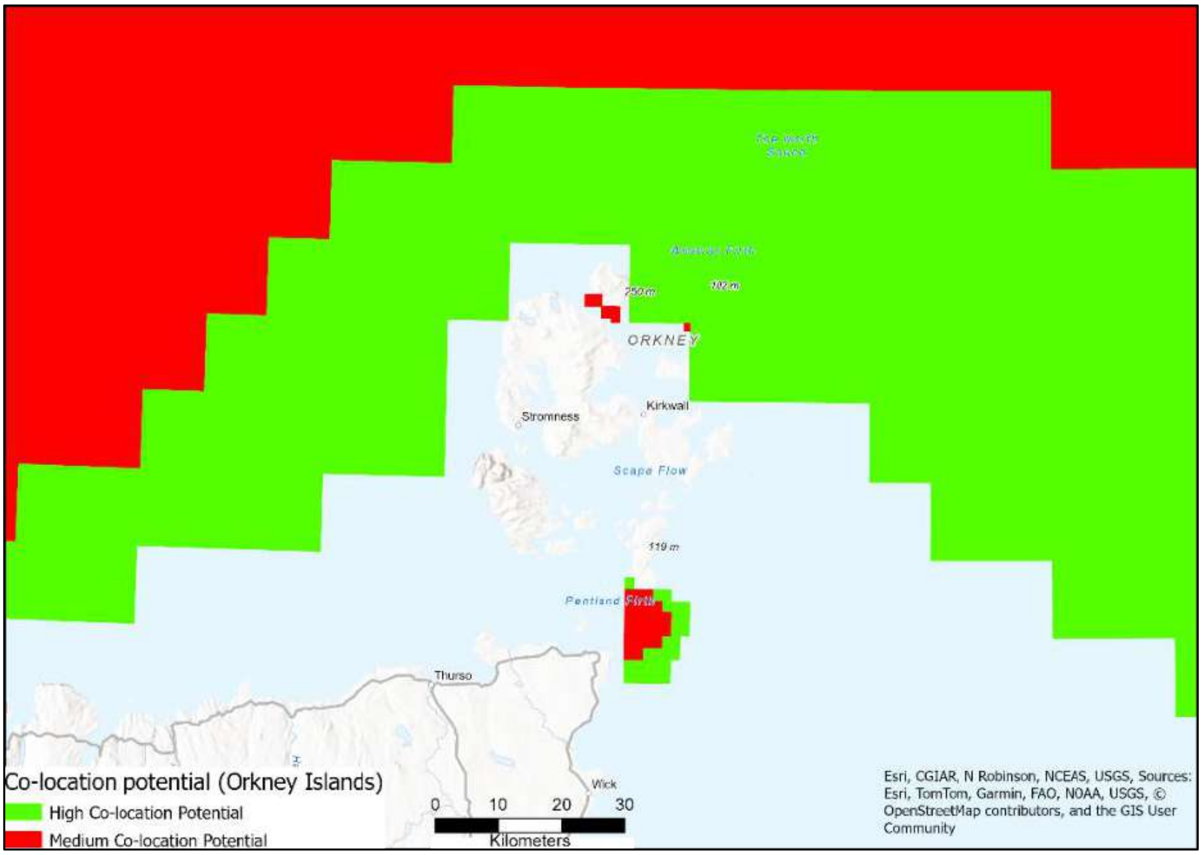

Figure 4: Co-location potential around the Orkney Islands (Data Source: UK Renewables Atlas; processed using ArcGIS)

feasibility.

The UK's marine energy resources analysis identified several areas of high co-location potential. One of which was the Orkney Islands, an archipelago community located off the North coast of Scotland with abundant marine energy and high wind resources.

2.5.1 The Isles of Orkney

These favourable conditions for marine energy generation have led Orkney to have a pivotal role in the development of nascent technology and is home to the European Marine Energy Centre (EMEC) [16], the world's first dedicated testing facility to support advances in research and innovation in the marine energy sector. The unique position of the Orkney Isles makes it an ideal location for the testing and deployment of both wave and tidal energy devices. The Billy Croo site has favourable conditions of average wave heights of 2-3 metres and peaks up to 18 metres; this makes it the ideal testing location for WEC and currently is supporting the commercialisation of the AWS Ocean Energy Wave Swing and Ocean Energy's 0E35 WECs [22]. Similarly, the Fall of Warness has provided the ideal testing location for tidal Stream Energy converters owing to its high tidal resources of 4 m/s [23]. EMEC aims to utilise these abundant marine energy resources to accelerate the development of emerging technologies from low technology readiness levels (TRL) to commercial viability [24]. As such, Orkney is at the forefront of wave energy and tidal stream technology innovation, with several significant projects and initiatives in progress.

Orkney has successfully leveraged its unique natural resources to drive its decarbonisation. Since 2013, Orkney has been self-sustaining by generating 100% of its electricity demands from renewable energy [25]. However, Orkney has limited energy storage assets, which creates a dependency on the temporal generation conditions and reduces the resilience of the local energy system. The addition of energy storage adds flexibility to the system and the provision of an around-the-clock energy supply. Although Orkney is ideally situated in terms of natural resources, it is a remote island community with limited grid connectivity to the Scottish mainland. It is, therefore, favourable for the local community to invest in energy storage to reduce dependency on energy imports in terms of energy resilience and economy. The £28.5 million ReFLEX project aims to create a digitally managed integrated energy system in Orkney by utilising battery storage, electric vehicles, and smart control systems to optimise renewable energy production [26].

Hydrogen also offers a sustainable storage solution for the Isles of Orkney, allowing the use of generation assets when conditions are less favourable to electricity production. The BiGHIT project, which ran from 2018 to 2022, saw the installation of a 1 MW PEM electrolyser on the Isle of Shapinsay by the manufacturer ITM Power [27]. The project left a legacy of community awareness of the entire hydrogen value chain and its potential application for the archipelago. Moreover, hydrogen presents an opportunity to achieve holistic decarbonisation of the island's energy system. Several of the main economic activities in the region, such as fishing, agriculture, and whisky distilleries, are dependent on fossil fuels and will be unable to achieve Net Zero through electrification alone. For these industries, hydrogen fuel provides a viable means for sustainable operation. Although Orkney has made significant strides in the decarbonisation of the electricity sector, in terms of primary energy sources it is largely still dependent on fossil fuels, which represent greater than 75% of total energy consumption [28].

2.5.2 The Ayre Floating Offshore Wind Farm

The Ayre project is a 1 GW floating offshore wind farm located 33 km off the east coast of Orkney, as illustrated on Figure 5. The wind farm was granted seabed rights in the ScotWind leasing round in 2022, and construction will be across two stages, taking place between 2029 and 2033 [29].

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Figure 5: Location of the Ayre wind farm project

The wind farm has a planned connection point to the substation at Keiss on the mainland. In this report, an additional connection point on the Isle of Orkney is explored; this electricity could be used to meet the hydrogen demands of the community, enabling the holistic decarbonisation of the Orkney Isles. This is mutually beneficial for both the Orkney community, which will increase their energy resilience, and the UK-wide electricity network, which will gain from the systemic benefits of an increase in localised demand.

As the UK evolves its energy system to meet the needs of Net Zero, offshore wind has emerged as one of the key technologies delivering green electricity to the UK. From the wind potential maps, it is clear that the UK has a high offshore wind resource, the greatest distribution of which is located around Scotland. This has driven substantial developer interest in the North Sea and the Scottish marine area for FOW [30]. This is demonstrated in the highly successful seabed leasing for the ScotWind sites. Despite this, there is now an underlying misalignment in the energy consumption of the UK and offshore wind generation.

The current electrical grid cannot efficiently distribute electricity from the peripheral generation sites to the points of use, i.e., from northern Scotland to central and Southern England, due to thermal constraints, which affect the carrying capacity of the network. This has led to the curtailment of wind farms, resulting in a loss of generation amounting to £5062.691 million in payments to wind developers from 2023-2024 [31]. The Arven wind farm, like other projects, would be subject to these constraints on the electricity network. Energy storage or hydrogen production and storage can enable grid management and the effective utilisation of electricity to decarbonise the whole energy system of the Orkney community.

3. MODELLING METHODOLOGY

The Catapult developed the co-location model to better understand the financial and technical implications of co-locating generation and flexibility assets, supplying multi-vector demands, and/or generating revenues from the wholesale market. The co-location model takes the following parameters as inputs:

- Techno-economic features (e.g., CAPEX, OPEX, efficiency, etc.) of the technologies modelled (FOW, wave and tidal).
- Range of technology scales available for optimisation.
- Weather and price profiles.

Based on these inputs, the model optimises the size and dispatch (i.e., hour-by-hour operation) of the different systems to maximise the site's economic viability. The model outputs the optimised size and dispatch schedule within the allowed techno-economic boundaries.

Figure 6 illustrates the inputs, outputs, general process of the model, and how it was implemented in this project.

Within this project, the model offers insights into the optimal sizing of hydrogen generation, storage assets, and export pipes. This is done in the context of pre-existing or planned offshore wind generation sites that may be impacted by avoidable curtailment or constrained capacities on power.

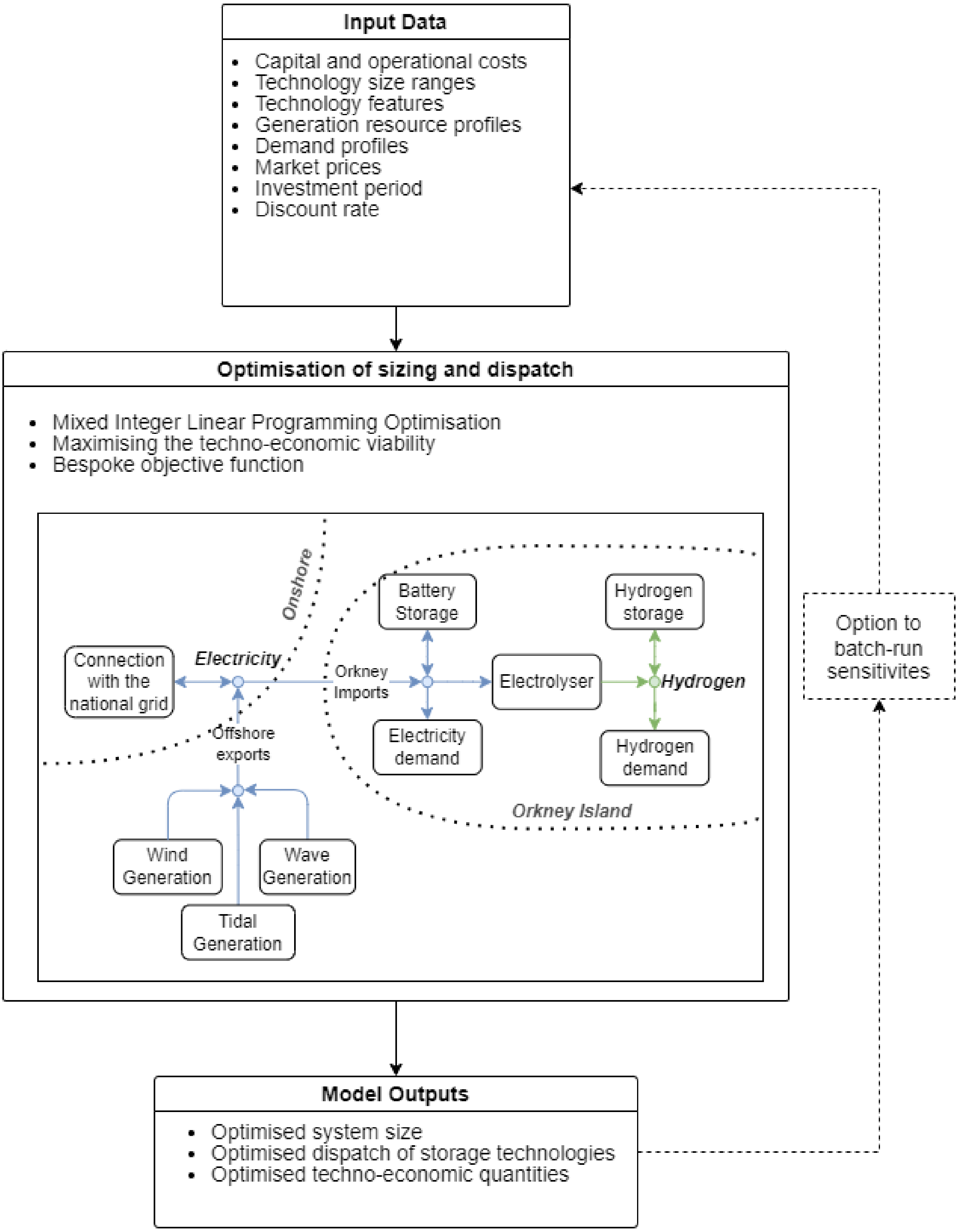

Figure 6: Illustration of the flow of information in and out of the co-location model

3.1. Model inputs

The co-location model relies on a range of inputs needed to evaluate the integration and performance of floating wind, wave, and tidal energy technologies. This section defines the key data and parameters used in the analysis and is structured to ensure a clear understanding of the model's foundation. Additionally, by incorporating economic, technical, and performance-related inputs, the model aims to provide an extensive assessment of co-location potential for offshore renewable technologies.

3.1.1 Cost and efficiency parameters

One of the crucial inputs of the co-location model is the costs per unit of installed capacities. The CAPEX function used is:

$$CAPEX_T = CAPA_T^P * CAPEX_{per\ kW} + CAPA_T^E * CAPEX_{per\ kWh}$$

Where $CAPA_T^P$ refers to the power rating capacity of the technology, $CAPEX_{per\ kW}$ is the cost per unit of installed power capacity. Similarly, $CAPA_T^E$ and $CAPEX_{per\ kWh}$ are only applicable for storage technologies, as $CAPA_T^E$ corresponds to the maximum volume of energy that can be stored in the unit, and $CAPEX_{per\ kWh}$ the cost per unit of energy capacity. The resulting capex $CAPEX_T$ is then added to other technologies and forms part of the cost function. The power (and energy) capacity are the decision variables of the model.

Similarly, the OPEX is defined with the same function except that the costs are homogenous to £/kW/year and £/kWh/year and therefore occur every year of the project's lifetime.

This section outlines the key costs and performance inputs for FOW, wave, tidal Stream Energy, electrolyser, hydrogen storage, and battery storage technologies. Table **2** shows the technical and economic inputs used in the model. The values for tidal Stream Energy are based on a 2023 DESNZ report [32], whereas wave energy is sourced based on data from ETI's Offshore Renewables programme WEC System Demonstrator [33]. The financial figures for the FOW farm were obtained from the 4C offshore data archive [34] , whereas the PEM electrolyser efficiency is based on data from various manufacturers, electrolyser CAPEX and OPEX were derived from interpolating costs from the literature.

For hydrogen storage, the capital cost per kWh is taken from [35] for pressurised containers. The power costs elements of the CAPEX (£/kW terms) are assumed to be mostly born by the electrolyser. The remaining 35 £/kW corresponds to the cost of equipment required to compress and extract the hydrogen to and from the storage tanks. The OPEX is assumed to be 5% of the CAPEX. The cost of battery storage corresponds to grid-scale lithium-ion battery costs taken from the Lazard report [36], where the OPEX is derived with an estimated OPEX of 4% of capex.

Table 2: Technical and Economic Inputs for Co-Location Model

Parameter	Floating Wind	Wave Energy	Tidal Energy	PEM Electrolyser	Hydrogen Storage	Battery Storage

CAPEX (£/kW)	4979	6209	3269	450	35	170
CAPEX (£/kWh)	-	-	-	-	8	47
OPEX (£/kW/year)	38	70	42	16	0.25	7
OPEX (£/kWh/year)	-	-	-	-	2	2
Efficiency (rate)	-	-	-	0.67	0.9	0.85

3.1.2 Profiles

The performance profiles for floating wind, wave, and tidal energy were generated using the co-location model, with the Ayre Floating Offshore Wind Farm in the Orkney Islands as the case study location, as described in the scenarios section.

- Floating wind and tidal energy profiles were created using wind speed and tidal speed data (m/s) obtained from Copernicus Marine Service [37], and applied to their respective turbine power curves.
- The wave energy profile was generated using significant wave height and peak period data with the power matrix from the HOPP model[38].
- The demand profile reflects the electricity demand patterns produced using the EnergyPath Networks tool, developed by the Catapult as part of the ITEG - *Integrating Tidal Energy into the European Grid* project [39], providing a context for the annual resource availability.
- The wholesale market price profile was generated using the ESC wholesale market model, based on 2015 renewables availability and demand data. The wholesale market model was successively run using national energy system generation capacities from all four Future Energy Scenarios (FES) 2022 scenarios for 2030. The resulting market price profiles were averaged to remove the high swings from specific renewable generation profiles while providing the general trend of fluctuations.
- The data for the year 2015 was used for the demand profiles and renewables generation profiles because this was the most recent year for which the data was available for all technologies and demand at the time of obtaining the data.

3.1.3 Availability Factor profiles

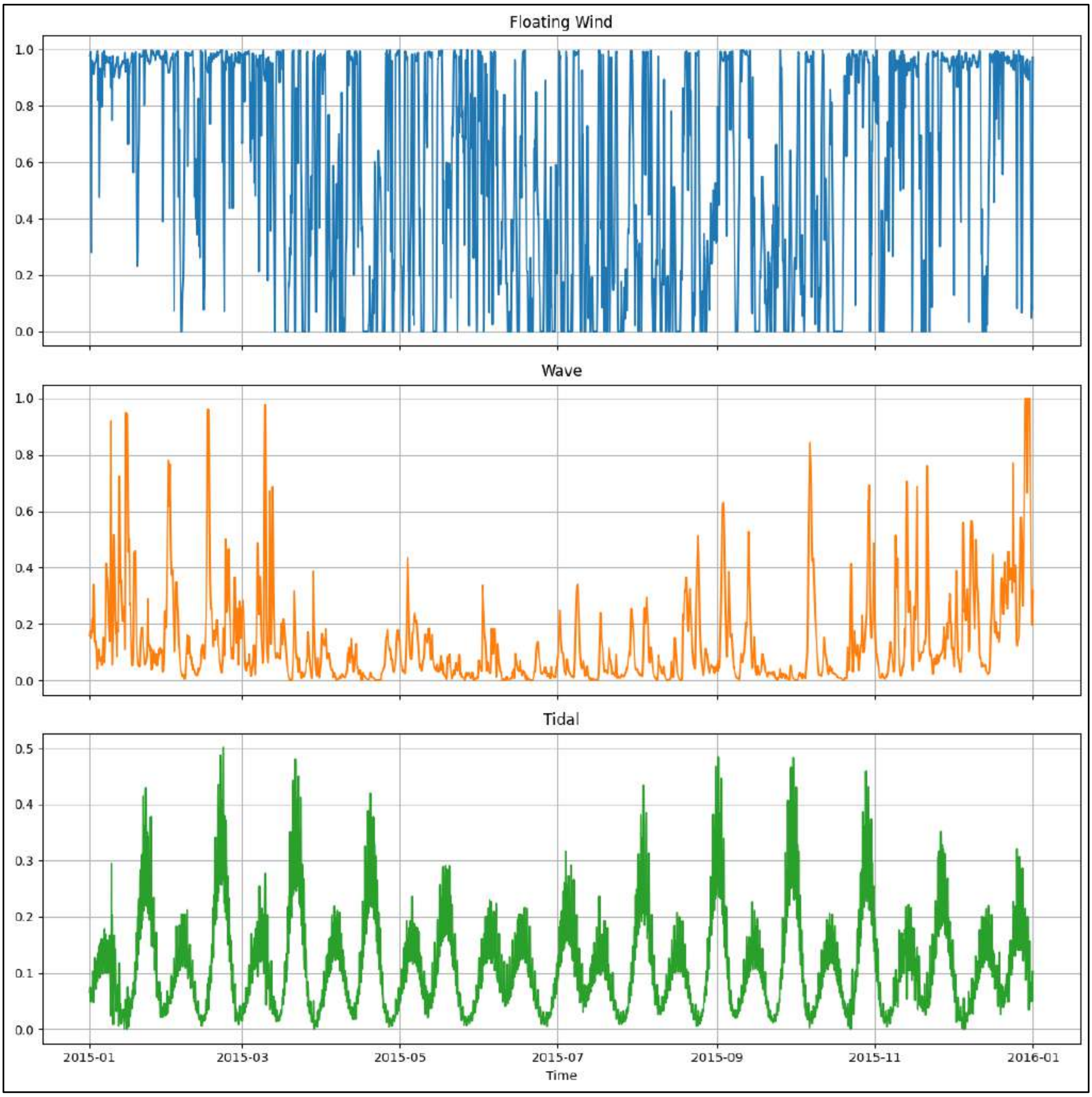

Figure 7: Availability Factor Profiles for Floating Wind, Wave, and Tidal Energy

Figure 7 shows the availability factor profiles for floating wind, wave, and tidal energy technologies over the course of the year 2015. Each subplot represents how the availability of each technology changes over time, reflecting the variability in resource conditions. The actual output (excluding curtailment) for each technology can be obtained by multiplying these profiles with the installed capacity of that technology.

3.1.4 Demand Profiles

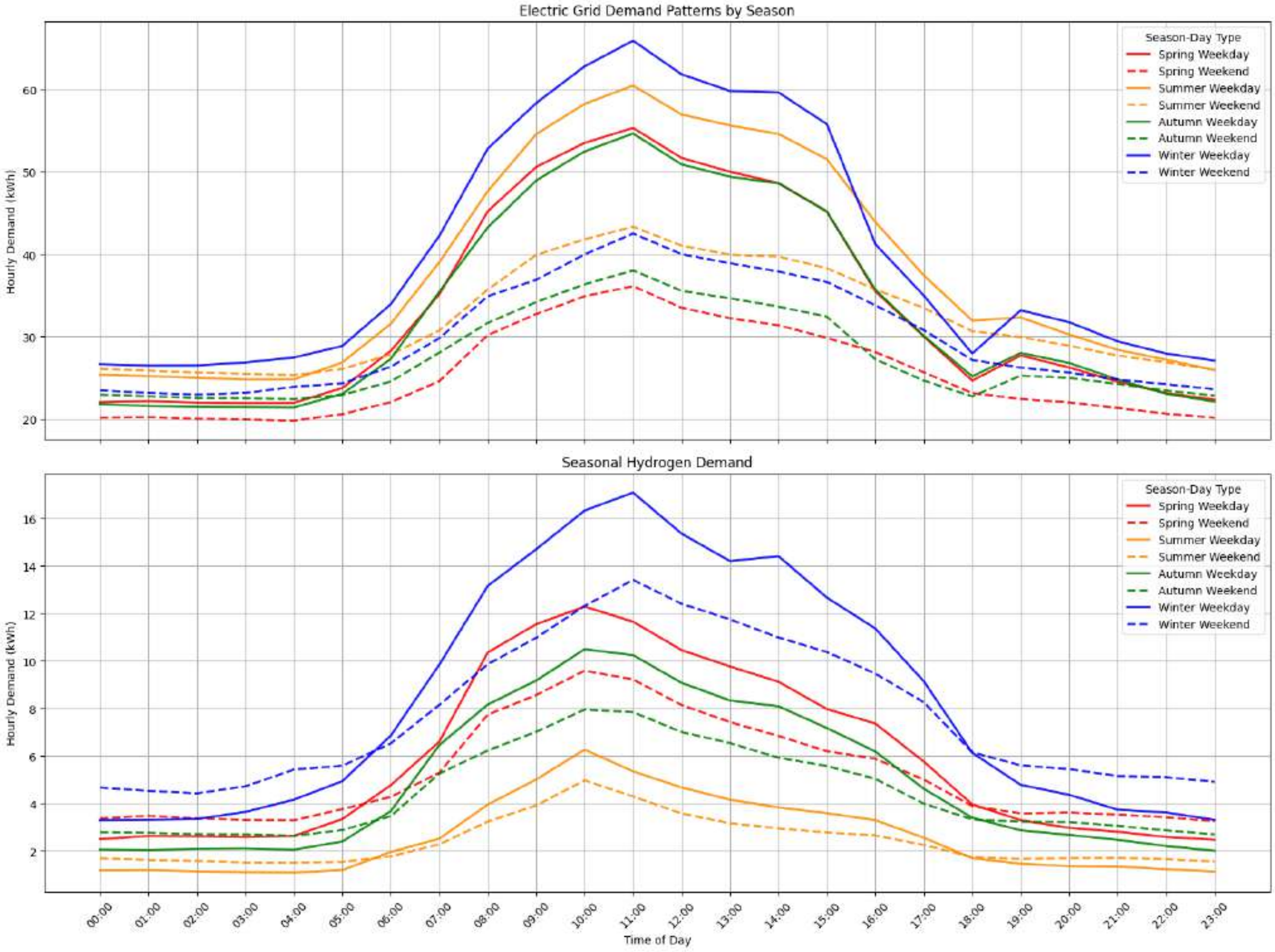

Figure 8: Electricity and Hydrogen Demand Profiles for Scenario 7 (S7)

The demand data for both the electricity and hydrogen demands was sourced from modelling results produced using the EnergyPath Networks tool, developed by the Catapult as part of the ITEG project [39]. This tool was applied to model energy systems across the Orkney Islands, generating detailed half-hourly demand profiles for each energy vector.

The demand profiles were generated separately for weekends and weekdays and for each season in the year. The yearly hourly profiles were then obtained by concatenating five weekdays and two weekend days to form 52 weeks (13 weeks per season). The resulting profiles are shown Figure 8 as implemented in the model.

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3.1.5 Wholesale Market Price Profile

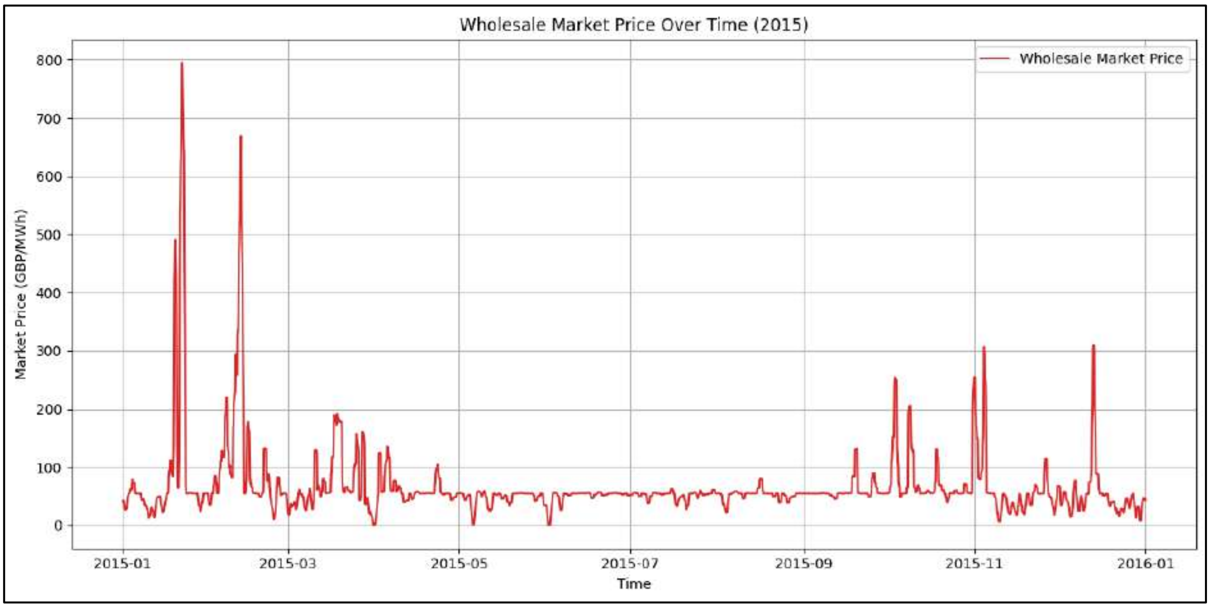

Figure 9: Wholesale Electricity Market Price Trends (2015)

The wholesale market price profile is an exogenous input to the model. It is implemented in the co-location model to represent the price at which the model can exchange electricity with the rest of the network. It, therefore, brings information about price variations through time.

The Catapult's Wholesale Market Model (WMM) generated the market price profile. The WMM inputs an energy system description in terms of installed capacities, national half-hourly availability factors for renewable energy, and a half-hourly demand profile. These time series typically need to cover a full year. The WMM also requires marginal costs for each of the technologies. The market simulation calculates the spot price each time based on the merit order and the demand during each settlement period.

The resulting market price profile used in this project is displayed on Figure 9. It was obtained by using all four FES scenarios for the year 2030, the demand profile for 2015 scaled to 2030 growth predictions, and the national availability profiles for renewables were obtained on the Renewables Ninja platform [40].

The profiles show much variability in the colder months of the year. This is due to a mix of higher and more variable demand (due to lower temperatures), lower photovoltaic outputs, and more variability in wind generation.

4. Scenario 1: Results and Discussion

This section presents and analyses the results of running the co-location model on the Orkney Island site as a case study. The impact of renewable generation CAPEX, energy storage availability and cost,

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and grid constraints are analysed in terms of their impact on installed capacity, operation, and economic viability.

4.1. Orkney Island Site Diagram

Figure 10 illustrates how the Orkney Island site was represented using the co-location model. The blue arrows represent the flows of electricity, and the green arrows represent hydrogen flows.

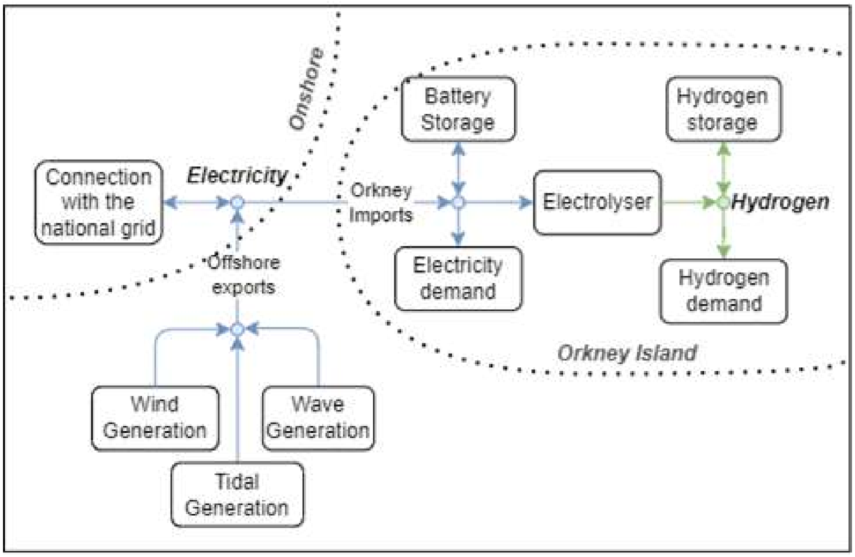

Figure 10: Representation of the Orkney site in the model

The island is connected to the rest of the grid via a single electrical link, which feeds the electricity demand, supplies the electrolyser, and to which the battery storage unit is connected. The electrolyser generates all the hydrogen consumed and stored on the island, and there is no pipe connection to any external hydrogen site. Note that the model is allowed to use the battery storage unit to export back to the main UK grid. However, the stored hydrogen cannot be converted back to electricity, thus it can only be used to provide hydrogen demand.

4.2. CAPEX sensitivity

Currently, the high CAPEX associated with renewable energy projects, particularly those involving wave and tidal stream technologies, is a significant barrier to their economic viability, as they still require substantial upfront investments in research, development, and infrastructure before they can begin generating revenue. Although more testing and development of marine energy technologies is ongoing in places like EMEC in Orkney and Wavehub in Cornwall, the costs associated with these projects remain high.

To this end, the initial model run included all the inputs, which led to the model deciding not to install any renewable generation capacity. This indicates that the revenues generated by selling renewable energy to the grid would not make up for the upfront investments. This was particularly true of wave and tidal stream and highlights that novel marine technologies remain too expensive to be economically viable in a site such as the Orkney Islands. Although the isolated nature and geographical

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conditions of the Orkney Isles lead to favourable conditions for renewable energy generation, such as high winds and strong peak wave heights, these geographical and metocean conditions result in high installation and maintenance costs.

To determine the necessary price reduction for marine renewables to become economically viable, the model was run a number of times with progressively lower technology costs.

For FOW, the reference price of 4979 £/kW was incrementally reduced until the model started to install FOW capacity. The impact of CAPEX on the NPV of the site is shown in Figure 11, where it can be observed that the model installed FOW at a 4530 £/kW value, about 91% of the reference value. In light of the above, this suggests that although FOW costs are currently high, FOW is very close to becoming an economically viable solution. This result is put into perspective considering the projected cost of FOW is by 4C offshore for 2030-35 of 3313 £/kW, well below the viability threshold.

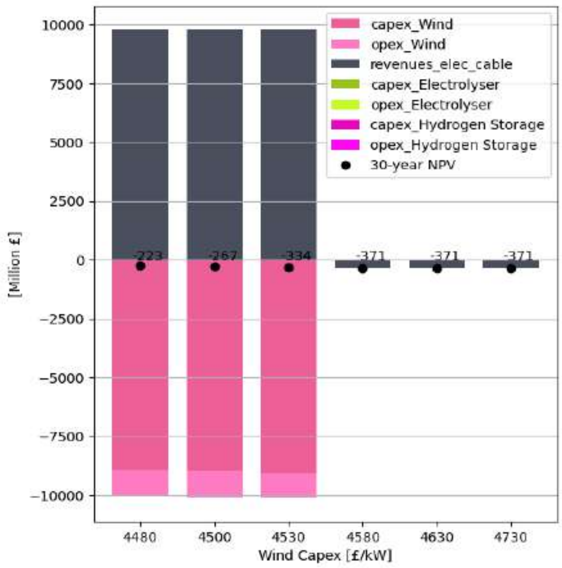

Figure 11: NPV and NPV contributions for varying Wind Capex values

For the rest of the project, a value of 4500 £/kW will remain close to the reference value while ensuring that the model constraints do not push FOW outside its feasible options. This is felt justified given the much lower value projected by 4C offshore.

The same CAPEX sensitivity approach was applied to the other two offshore renewable energy generation technologies, namely wave and tidal, to determine the threshold cost at which they become economically viable. These results are more challenging for wave and tidal technologies than for FOW. Figure 12 shows the outcome of the CAPEX sensitivity analysis for wave energy (left) and Tidal Stream Energy (right); for these technologies, the threshold values obtained are 807 £/kW and 4787 £/kW, corresponding to 13% and 30% of their reference costs, respectively. A wider set of values was tested in the sensitivities; however, only values close to these thresholds are displayed in Figure 12 for

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clarity reasons. This necessary reduction illustrates the greater effort required in technological development and innovation to render these technologies economical.

The output of the CAPEX sensitivity analysis means, like for FOW, a slightly lower value than the

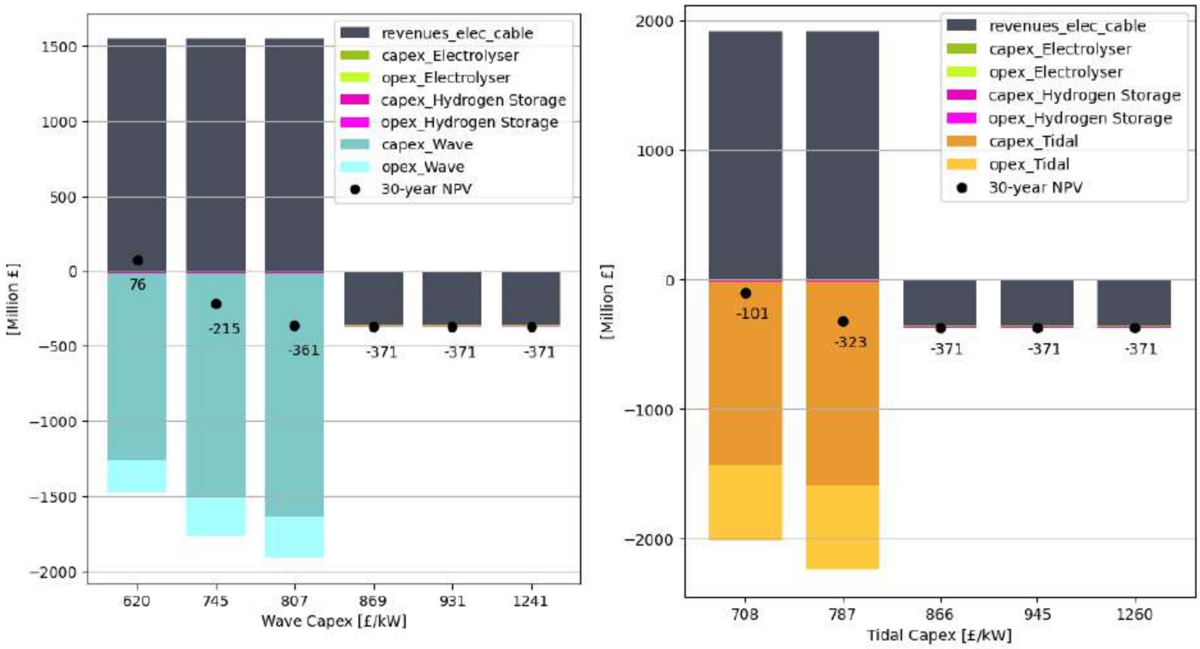

Figure 12: NPV and NPV contributions for varying wave Capex values (left) and tidal Capex values (right)

threshold will be used for wave and tidal stream for the remainder of the co-location model runs. The values for all technologies are summarised in Table 3.

Table 3: summary of technology capex values

Technology	*In £ / kW of installed capacity*			
	Reference value	**Projection for 2030-35**	**Value at which the model starts adding tech**	**Value chosen for the rest of the study.**
Wind	4979	3313	4530	4500
Wave	6209	5675	807	800
Tidal	1575	1470	787	780

An additional route for cost reduction is the reduction of logistics costs associated with the technology construction and commissioning. Co-location, in this case, could provide benefits by providing shared port infrastructures between technologies, as well as boats and the labour force required to moor the systems to their offshore locations. Various degrees of co-locating FOW and wave and the economic impacts of these levels of sharing have been explored comprehensively by Wave Energy Scotland [5].

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4.3. CFD Sensitivity

The model was additionally run by implementing Contract for Difference (CFD) mechanisms to sell renewable energy instead of directly trading on the wholesale market. The CFD mechanism helps stabilise revenue for renewable energy projects by setting a fixed price for electricity, i.e. the strike price. Using the co-location model approach, implementing a CFD price instead of an exchange on the market comes down to imposing a flat price for the sale of electricity. The CFD values were taken from the Allocation Round 6 auction, which took place in 2024 [41]. The strike prices were 139.93 £/MWh for FOW and 172 £/MWh for tidal. The maximum of 2GW for the offshore generation site was maintained. It should be noted that the CFDs for FOW and tidal in the model are set to 197.30 and 242.52 £/MWh, respectively, to account for 2012 to 2024 sterling inflation of 141% [42]. For comparison, the average wholesale market price for the profile used in this work was about £67/MWh.

The results for the default CFD run are that the model chooses only to install FOW and to maximise its capacity within the 2GW network connection limit set in the model. This result suggests that, when competing for connection capacity, FOW is still more competitive than the other marine renewables, even if their CFD strike price is higher than that of FOW.

Sensitivities were run by increasing the CFD price to determine the price at which wave and tidal became viable. For the Orkney site, the results showed that a CFD of 437 £/MWh for wave and 534 $/MWh for tidal lead to them favoured compared to wind. It should be noted that the CFD values acted as threshold: once a CFD is high enough, the model switches to maximise that technology's capacity and removes the other two.

Although the actual threshold values for CFD would slightly differ on a site-by-site basis, this suggests that the CFD mechanism is not appropriate for the co-location of multiple renewable resources if these compete for capacity. The revenue structure with capped total capacity means that the optimal solution is when one renewable resource takes the full capacity. The actual renewable resource that “wins” is the one with the highest difference between CFD revenues and annualised costs. The optimal cost is obtained if that technology's capacity is maximised and the others minimised. An example of potential improvement on the current CFD schemes could be hybrid metering, as mentioned in [43].

4.4. Impact of excluding storage

Notably, when running the co-location model with the reference costs as introduced in the previous section, the model did not build any battery storage capacity. Further, this remained true even with the reduced renewables costs introduced above. However, the model consistently builds hydrogen storage for both renewable costs. In both model runs with reference or reduced values for renewables, the optimisation always includes hydrogen storage at 14.4 MW and 508 MWh.

A sensitivity was run where the model was not allowed any hydrogen storage to determine the role played by hydrogen storage. The results in terms of cost savings are shown in Figure 13. The hydrogen storage costs (CAPEX AND OPEX) are partly compensated by a small reduction in the electrolyser size,

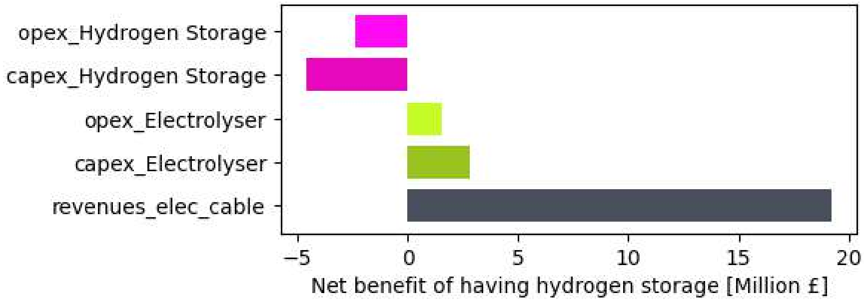

Figure 13: Costs savings occurring when allowing hydrogen storage over the project's lifetime

from 20.11 MW to 13.87 MW. However, the main benefit of allowing hydrogen storage is reducing electricity costs.

Figure 14 shows a snapshot of the results for February and March 2015. The top graph shows the difference in hourly operation of the electrolyser for the cases with and without hydrogen storage. The market price for that period is also included on the right-hand side y-axis. The bottom graph shows the resulting hourly cost of electricity fed to the electrolyser only.

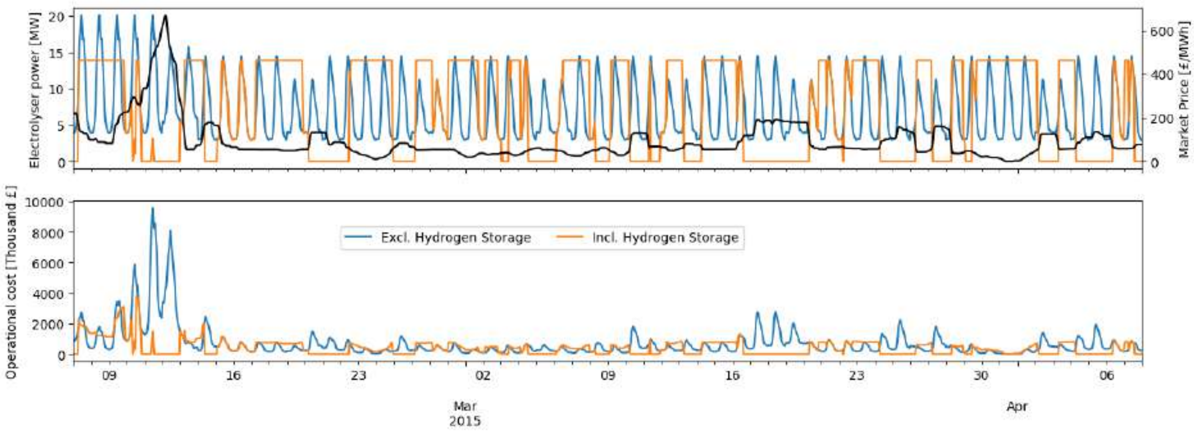

Figure 14: Illustration of operational cost of electricity over time with and without hydrogen storage

The operational patterns are visibly different, which applies to the simulated period. When hydrogen storage is present, the electrolyser is either switched on or off irrespective of present demand, as the short-term variation in demand is smoothed out by the storage unit (not represented on Figure 14). When no storage is present, however, the current hydrogen demand determines the electrolyser operation, and therefore, electricity must be bought from the grid at that time, meaning that the electrolyser and hydrogen demand are exposed to fluctuations in the electricity prices. The addition of a hydrogen storage tank allows for more flexibility. It enables the electrolyser to be selective over its operation, i.e., the electrolyser is switched off when the price of electricity is high (relative to the few

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previous and following hours), and the electrolyser is switched on when the price is low, even if the demand for hydrogen is lower, as the excess hydrogen generated can be stored.

4.5. Impact of storage cost

As mentioned above, the model excludes battery storage for the costs considered. Therefore, the storage cost sensitivity analysis was run by varying the capital cost of both storage technologies and assessing the resulting impact on the optimal installed capacities.

The main result of the sensitivity analysis was that the capacities of both storage technologies (e.g. batteries and hydrogen storage) do not depend on one another. In other words, all else being equal, the lower the cost of a storage technology was impacting its optimal capacity; however, it was not affecting the optimal size of the other technology.

As shown in Figure 15, the optimiser only chose to install battery storage for CAPEX values of about 25% of the reference value and did not install any battery storage for cost values of 50% and higher. The results for hydrogen storage are slightly more nuanced. Firstly, the 500 MW installed when the storage cost is zero is an artefact of this type of optimisation; the hydrogen unit never reaches charge or discharge flows of 500 MW because there is never such a high source or demand level. The model consistently installs about 15 MW for non-zero hydrogen storage costs at any other cost. This reflects the maximum levels of hydrogen demand of approximately 17 MW in winter.

Most other components are unchanged, except the relationship between hydrogen storage and the electrolyser, where the higher the hydrogen storage CAPEX, the lower the electrolyser capacity. This is an unexpected result, as one would expect the electrolyser capacity to increase to make up for smaller storage units. However, in this case study, the peak hydrogen demand is about 17MW, and the optimiser installs about 12-14MW$_{elec}$ of electrolyser (depending on the sensitivity studied). The

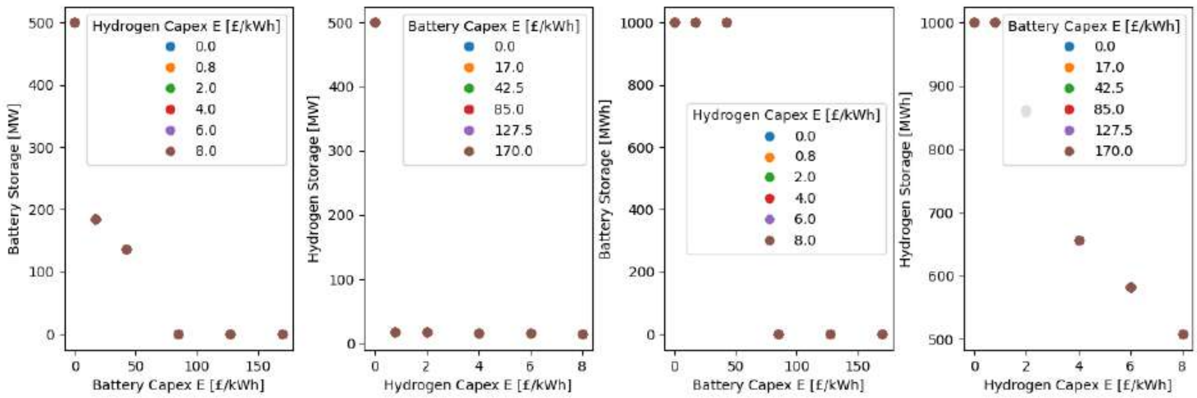

Figure 15: Impact of varying the capex of storage technologies on the resulting optimal sizes (power and energy) of these storage technologies

electrolyser size is, therefore, highly driven by the maximum required flow for charging the hydrogen store. However, when the hydrogen CAPEX is increased, this maximum charging flow is reduced since the unit installed gets smaller and costs more. As a result, the optimal electrolyser size decreases with the hydrogen storage size for the values studied. This was confirmed by looking at the sensitivity

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without hydrogen storage from the previous sub-section. In that sensitivity, the electrolyser size was increased to about 20 MW_{elec}, corresponding to a 17 $MW_{hydrogen}$ capacity.

4.6. Impact of grid constraints

This section analyses the impact of applying grid constraints to the site on the resulting optimal technology sizes, NPV and flows. We first look at the impact of limiting the maximum allowed import and export powers.

4.6.1 Static connection constraints

Table 4 shows the results for optimal installed capacities under different import and export limitations sensitivities. The model was run for all nine combinations of values 0, 50 and 100 MW for import and export (3 times 3 combinations).

Table 4: Optimisation results for the different import/export constraint sensitivities

		Export Capacity [MW]			
		0	**50**	**100**	
Import capacity [MW]	**0**	10.1	7.2	6.7	*Wind [MW]*
	50	9.0	14.0	34.4	
	100	16.7	64.1	114.3	
Import capacity [MW]	**0**	1002.4	835.7	679.0	*Wave [MW]*
	50	42.1	75.7	84.5	
	100	17.1	22.1	25.5	
Import capacity [MW]	**0**	501.2	657.2	798.8	*Tidal [MW]*
	50	49.7	94.6	130.7	
	100	17.4	25.9	26.7	
Import capacity [MW]	**0**	10.0	10.2	11.4	*Electrolyser [MW]*
	50	14.0	14.2	14.1	
	100	13.8	13.9	13.9	

		Export Capacity [MW]			
		0	**50**	**100**	
Import capacity [MW]	**0**	8.6	11.0	13.2	*Hydrogen Storage [MW]*
	50	17.1	16.3	14.7	
	100	14.4	14.4	14.4	
Import capacity [MW]	**0**	59.6	81.0	141.2	*Battery Storage [MW]*
	50	11.4	11.0	11.0	
	100	0.0	0.0	0.0	

		Export Capacity [MW]			
		0	**50**	**100**	
Import capacity [MW]	**0**	391.9	424.2	608.4	*Hydrogen Storage [MWh]*
	50	518.2	516.5	506.8	
	100	506.8	506.8	506.8	
	0	1000.0	1000.0	1000.0	

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Import capacity [MW]	**50**	36.1	22.2	20.2	*Battery Storage [MWh]*
	100	0.0	0.0	0.0	

		Export Capacity [MW]			
		0	**50**	**100**	
Import capacity [MW]	**0**	- 1,833.84	- 379.51	- 369.54	*NPV [Billion £] at 30 years*
	50	- 1,433.50	- 372.59	- 366.80	
	100	- 1,128.46	- 369.36	- 364.12	

The sensitivities were confined to this range, as the maximum demand for hydrogen and electricity never exceeded it (peak net electricity demand is approximately 65 MW and hydrogen 17 MW). The 0 MW limit represents the extreme islanded case, 50 MW corresponds to a connection size that does not allow for the full supply of the demand, and 100 MW corresponds to a realistic, slightly oversized connection size.

The results in Table 4 are colour-coded based on each technology's installed capacities for each combination of the maximum allowed import/export.

Firstly, the trade-off between the different renewable technologies is interesting to comment on, as they evolve in opposite directions to grid capacities.

- A high import / high export combination favours FOW. This is due to FOW's more stable output (see profiles, Availability Factor profiles section) leading to maximising export revenues.
- A low import/export combination favours wave technology, with additional tidal generation and nearly no FOW. This combination of renewables is primarily because since this sensitivity implies that all energy consumed must come from renewable sources, the amount of curtailment is bound to be high. Because wave has the lowest capacity cost, it also has the lowest cost of curtailed energy (a MWh of more expensive FOW is more "precious" than a MWh of less expensive wave in this context). As a result, the optimiser balances between maximising the match between supply and demand while minimising the overall wasted curtailment costs.
- Energy curtailed versus demand served for minimal storage size. The reduced wave cost explains why a large wave capacity is installed in this case, whereas tidal is favoured at higher CAPEX values, as its 12h oscillations are easy to match a roughly periodical 24h demand profile with a few hours' worth of storage.
- A low import / high export combination leads to high tidal and wave capacities with close to no FOW. This type of network constraint also requires the highest battery storage capacity. When looking at the operational results, the network exports are maximised most of the time with a nearly flat line at 100 MW. The battery store is mostly used to average out the tidal oscillations. The hydrogen storage also absorbs these oscillations through the electrolyser. The latter operates on a significantly less stable output than for more regular runs, i.e., with lower tidal oscillations.
- A high import / low export combination is the least favourable for renewables overall: the optimiser installs about 17 MW each on reduced renewables costs. It does not install renewable energy when running on the higher CAPEX values.

The impact on cost of the different combinations of import and export capacities is shown in Table 4. It should be noted that none of the scenarios studied reach economic breakeven after 30 years. However, Table 4 makes it clear that the driving factor is the export capacity size. In particular, the NPV drops significantly at zero export capacity due to the impossibility of generating revenues by selling the energy produced.

On the other hand, the optimiser can maintain a similar NPV value for all the other combinations, with a slight decrease as import capacity increases.

4.6.2 Dynamic connection constraints

A more dynamic approach to the network connection constraints was applied to estimate the impact of a network connection with a capacity that varies through time based on the conditions of the rest of the network.

The hourly wind availability time series was used to obtain such dynamic constraint profiles, assuming that the higher the wind availability, the more likely the network will be constrained. To represent this, a threshold was applied to the wind availability profiles of the north of Scotland (UKM6 region under the "NUTS2" classification from the Renewables Ninja platform). For periods of time when the availability factor was higher than the threshold value, the network was assumed to be constrained. Therefore, imports and exports were brought down to zero. The rest of the time, the full network capacity was available. Thresholds between 65% and 95% were used in steps of 5% to obtain multiple sensitivities, and the model was run for each.

The resulting installed capacities of technologies are shown in Figure 16. Unsurprisingly, when the constraint level increases (constraint threshold decreases), the level of FOW reduces. More specifically, below the 90% threshold value, the model almost stops installing wind generation. This can be expected, given the fact that the UKM6 wind and the Orkney FOW site are highly correlated with one another. As a result, the dynamic constraints tend to occur when the offshore wind generation is generally high.

Figure 16 shows that the installed capacity of overall renewable energy remains stable regardless of the constraint levels, except for very high constraint levels: at 65% constraints threshold, the optimal renewables capacity drops to below 500 MW.

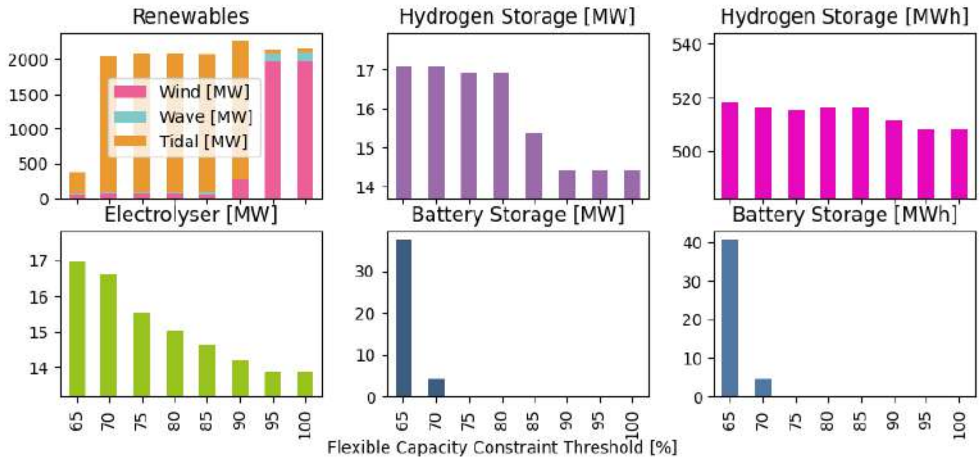

Figure 16: Installed capacities for the different technologies at all the threshold values for the network constrains

Below the 90% threshold, tidal energy almost entirely compensates for the reduced FOW generation. The techno-economic reason for the shift is visible in Figure 17. As the threshold decreases, the ability for wind to generate revenue shrinks. The 90% threshold value corresponds to the limit where it becomes equally economical to sacrifice the large revenues from the sale of electricity in favour of a cheaper renewable source – in this case, tidal, and maximise the capacity so its resulting investment is balanced by the revenues it achieves through electricity sales. FOW is not favoured at a lower threshold value partly by design: a lower threshold means the network is assumed constrained for lower wind generation in the north of the UK. Since the wind generation at the Orkney site is correlated with that in the rest of the north of the UK, a lower threshold implies network constraints in a particularly unfavourable way to FOW.

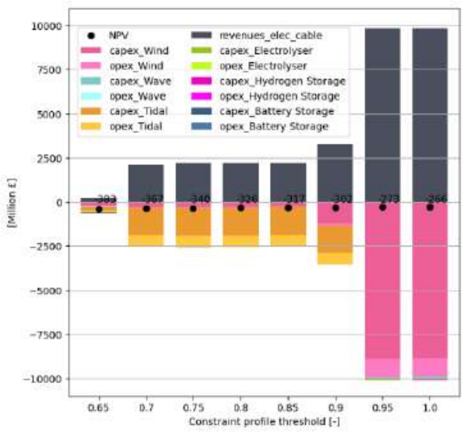

Figure 17: Evolution of the NPV and contributing factors for different constraint profile thresholds

Tidal becomes favoured at higher constraint levels, as it is the technology for which the investment costs are best compensated by revenues and its ability to supply the Orkney Island demand during constrained periods.

5. Conclusions

After a general survey of the co-location potential around the British Isles, the Orkney site was implemented in the co-location model. This location possesses a great combined potential for FOW, wave, and tidal generation, supported by projects like MeyGen and the West of Orkney Windfarm. Additionally, the Celtic Sea has shown a strong potential, with significant movements in floating wind and wave developments, such as the Erebus Project and areas of the seabed leased by the Crown Estate. Moreover, medium co-location potential is observed in the north-east of Scotland, particularly around the Orkney Islands. There are also small areas for potential exploitation off the coast of southern England adjoining the English Channel and in the confined areas of the Rockall Plateau in the North Atlantic Ocean. These areas may be less promising for large-scale projects but are ideal for small-scale or targeted projects. Although solar energy was not included in this case study of the Orkney Islands, there is potential for co-locating floating solar with other renewables in the southern regions like Cornwall and the Celtic Sea.

The model included three renewable generation technologies (FOW, tidal, and wave generation) and the modelled island demand for electricity and hydrogen. An electrolyser was included for hydrogen generation, as well as hydrogen storage and a battery storage unit.

The initial run results showed that the optimiser did not install any renewable generation or battery storage capacity under the reference assumptions for costs. The electrolyser was used to generate the bulk of the hydrogen by converting electricity directly bought from the wholesale market. Additional hydrogen storage was still present to smooth the operation of the electrolyser and allow the purchase of the extra electricity at a lower price.

Several sensitivities were run to understand the impact of:

- Cost reductions required for renewables to be profitable (i.e., for renewable energy generated to compete with grid prices).
- Switching to CFD mechanisms for renewable energy as opposed to market trading.
- Forcing storage in or out of the model and reducing their cost.
- Applying grid constraints to the model for the import and export of electricity.

The following insights were derived from analysing the run results:

- the current costs for FOW are on the verge of becoming profitable: a 9% reduction in capex compared to the reference cost for 2025-30 leads to economic viability. This is encouraging for FOW, given that FOW costs are projected to reduce by about 30% in the next 5-10 years.
- The costs of wave and tidal technologies present a greater challenge: for the Orkney site, an 85% and 70% reduction were required to reach economic viability.

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- Contracts for difference-style policies offer a great incentive to support a single technology by protecting from market fluctuation risks. However, even with high CFD strike prices for wave and tidal technologies, the optimal configuration was systematic with a single technology. As a result, careful consideration should be given to the design of supportive policies to ensure they do not short-circuit each other or exclude potentially beneficial combinations.
- Another way to reach economic viability is via cost reductions by sharing infrastructure during co-location projects' construction and maintenance phases. The costs implemented in the model were reflective of each technology's required investments and, therefore, did not include this type of logistical synergies.
- The cost of battery storage made it unable to compete with hydrogen. However, this is partly because parts of the hydrogen infrastructure (i.e., the electrolyser) were necessary to generate the hydrogen. This suggests that existing or non-negotiable infrastructure significantly impacts the remaining available, viable configurations.
- Battery storage was only installed in highly constrained sensitivities. Given the increasing network capacity constraints issues, this suggests that battery storage remains an important part of supporting renewable generation's co-location.

However, this study was limited to a specific site, so caution should be applied when attempting to generalise the results. However, a tool such as the co-location model is a great candidate for modelling a larger number of sites, and such an approach would allow us to draw more general insights.

Moreover, the modelling analysis from this report highlights several candidate areas for further investigation to promote the implementation of co-located generation. In the FOW context, the infrastructure and logistics required to commission a FOW site have great potential to be shared between other co-located systems [5]. This could include sharing land for storing parts during the commissioning phase and sharing boats and skilled workers for offshore installation and maintenance.

Finally, the analysis shows that a straightforward application of some existing supportive mechanisms (the contract for difference, in this case) may not allow a co-location site to exploit its full potential, because it would favour a single generation technology. This means innovative policies should be developed with the co-location aspect in mind.

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