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WIND ENERGY SCIENCE DISCUSSIONS

Economic Viability of Floating Offshore Wind in Portugal with Varying Market Conditions and Financial Support Mechanisms

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Abstract. This study assesses the economic viability of commercial scale floating offshore wind farms in Portugal, under a range of CfD mechanisms. A techno-economic model was developed to generate a synthetic range of time series wind and spot price data that creates financial revenue under varying CfD types, water depths, and distances to shore. Results are split into levelized cost of energy, net present value, and internal rate of return, and are influenced by a range of sensitivity analyses that help define the financial setting for successful floating offshore wind projects, including CfD mechanisms varying in type, value and duration. Results indicate that floating offshore wind shows potential in Portugal, but only under strong financial support, with outcomes heavily influenced by site characteristics, wind regime, and economic conditions.

1 Introduction

Strong and consistent winds that played their role in the age of exploration now present an opportunity for the development of marine renewable energy in the deep waters off the coast of Portugal. Offshore wind offers mature and proven technology but is generally limited to shallower marine areas with activity within Iberia. The deployment of floating wind (FOW) into deeper waters offers access to greater wind resources with less marine competition, boosting low-carbon energy generation whilst reducing the visual impact in coastal regions. Floating technology has grown and improved since the first full-scale prototype in 2009 (Skaare, et al., 2015), with early commercial farms commissioned in 2017 (Hywind Scotland, 30MW) (Jacobsen & Godvik, 2021), 2021 (Kincardine, 50MW) (Risch, et al., 2023) and 2023 (Hywind Tampen, 88MW) (Musial, et al., 2023).

Geopolitical events have caused costs to rise in recent years and reductions are necessary to achieve commercial deployment, and global installed capacity in the hundreds of GW (DNV, 2023). FOW must realise levelised cost of energy (LCoE) improvements through cost reductions to become economically viable and compete with fixed-bottom offshore wind and other renewable energy technologies. Site selection and resource optimisation are crucial to achieve this, alongside financial assistance that includes feed in tariffs, power purchase agreements, and Contracts for Difference (CfDs) that reduce risk and encourage private investment in this promising sector.

In 2020, as recorded by (Gomes, et al., 2020), 30% of Portugal's electricity generation was provided by coal and was responsible for 25% of Portugal's total CO_2 emissions. Energy policy was changed in 2018 to align with climate targets and

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coal was phased out of the system in 2022, as part of the "National Renewable Energy Action Plan" that established an emissions reduction pathway aiming for a 47% renewable energy mix by 2030. Such increases in variable renewable energy (VRE) require grid balancing capacities such as hydropower, says (Ramos, et al., 2014), which have increased from ~5GW (28% generation share) in 2010 to ~9.5GW (36% share) in 2020. Of this, almost 3GW is defined in the (Clean Energy Technology Observatory (CETO), 2022) as pumped hydro storage that can utilise Portugal's favourable high terrain and react quickly to balance demand with supply. This storage will play an important role as argued in (Bilbao-Terol & Gónzalez-Pérez, 2023) as a balancing mechanism for future higher capacities of floating wind generation, supplemented with large scale hydro-battery storage. Notwithstanding the lower costs of onshore wind and solar, (Silva & Sareen, 2021) argue that public attitudes vary, with community opinions and engagement often overlooked or bypassed, which presents an opportunity for floating wind development.

The Portuguese energy system is interconnected with Spain, helping to stabilise the grid and energy pricing and with fluctuating supply and demand. This connection broadens the generation, load, and storage mix, with Spain contributing more solar, and northern Portugal a large capacity of pumped-hydro plants. The national system has just over 20GW of installed power (REN, 2024), with average generation in 2023 exceeding 9GW, of which 85% was from renewable sources. On the demand side, peak consumption across all sectors was 8GW, with a 13.5GW future consumption pipeline expected to consist of hydrogen and extra domestic demand through electrification (Laboratório Nacional de Energia e Geologia (LNEG), 2023). The aim is to decarbonise the gas network through hydrogen and boost Portuguese energy security by reducing gas imports. Market spot price per MWh of generation was 93€ on average in 2023, 230€ in 2022, 73€ in 2021 and 31€ in 2020 (REN, 2024), highlighting volatility in the market.

This paper analyses the economic potential of commercial scale floating offshore wind in Portugal, for three different CfD types. The geospatial assessment is carried out at a range of locations and distances from shore across the entire coastline. Costs consider current macro trends (i.e. increased cost of materials as seen since the Covid-19 pandemic). The LCoE is used to assess projects with variation to location, wind resource and distance to shore/port. A sensitivity analysis is presented with adjustments to discount rate, capital expenditure (CAPEX), operational expenditure (OPEX), generation, CfD duration and strike price level, and spot price.

1.1 Support structure design

CfDs provide financial support to renewable energy systems by guaranteeing a price of energy which is usually supported through public funds. The aim is to establish a long-term revenue stream for the generator which minimises risk (Beiter, et al., 2024). Current CfDs do guarantee price but are still at risk to changes in volume, whether low or high. Future CfD methods have been proposed that aim to maintain price security and limit over-supply especially in low demand hours. They can either be formed of payments based on a reference generator or based on typical output.

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1.1.1 Traditional CfD

CfDs of this nature are generation-based which provide a stable price per unit of energy generated but are still at risk to volume changes, as discussed in (Wind Europe, 2025). A guarantee of payment for energy is not always best for a power system with significant variable renewable energy share, which can cost a power system through balancing costs, grid instability and price-cannibalisation through over-generation. CfDs can either be one-sided, where the market price above the strike price is kept, and can be more costly to sponsor. The other method is two sided, where underpayments are topped up and overpayments are returned, which maintains price consistency. Mitigation is possible for generation-based schemes, including using monthly average prices, or wind-weighted averages, but still are at risk during low-wind periods with revenues dependent on production.

1.1.2 Financial CfD

For the financial CfD method, as proposed by (Schlecht, et al., 2024) the generator receives fixed payments based on the size of the generator plant irrespective of generation, whilst repaying the revenues based on a reference generator and the market spot price. With fixed payments, the risk profile is reduced and revenues consistent and predictable, even in low wind speed months. A downside is that there is less exposure to windfall events, reducing the ability of generators to respond to high price and/or high wind periods.

1.1.3 Capability CfD

Capability-based CfD is another generation-independent method outlined by (Kitzing, et al., 2024) which creates a reference capability which payments are measured against. The goal is to accurately model the generation profile of the farm through the accurate modelling of the power curve, losses and wind profile. This creates a fair assessment of the farm's potential, rewards efficient operation and high availability, whilst creating forecastable revenues and again lowering the risk of the asset from an investor's perspective.

1.2 Techno-economic evaluation metrics

Evaluation methods, from a techno-economic perspective, utilise consistent and useful techniques to quantify the expected technical and financial performance of a prospective floating offshore wind farm. Three such methods are widely used as indicators for VRE project assessment: LCoE, Net Present Value (NPV) and Internal Rate of Return (IRR).

The main function of LCoE is as an evaluation metric for energy generation projects and is improved through cost reductions and energy generation increases. Benefits lie in its simplicity, wide industrial acceptance and understanding, quick assessment, easy modification, and flexibility to assess all energy generation technologies. The LCoE calculation is the lifetime costs of the project (CAPEX, OPEX and DECEX) divided by the lifetime energy generation. Both terms are discounted to account for the time value of money, recognizing that the CAPEX investment has a higher present value today, and that energy generated now is more valuable than the same energy sold in the future.

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$$LCoE\left(\frac{€}{MWh}\right) = \frac{lifecycle\ costs}{lifecycle\ generation} = \frac{\sum_{t=-3}^{n}\frac{CAPEX_t+OPEX_t+DECEX_t}{(1+r)^t}}{\sum_{t=-3}^{n}\frac{E_t}{(1+r)^t}}, \quad (1)$$

$CAPEX_t$ is the capital expenditure, $OPEX_t$ the operational expenditure, $DECEX_t$ the decommissioning costs, E_t the energy generation (MWh), all in year t. r is the discount rate, and n is the project lifetime.

A large benefit of LCoE analysis is that it is applicable to all forms of energy generation. The metric can lack a theoretical foundation, which (Aldersey-Williams & Rubert, 2019) explored via comparison with other cost of energy metrics. It was still found to be the preferred method, but weaknesses were identified in the discount rate, inflation, and uncertainties in future commodities.

Another critical review of the LCoE metric by (Shen, et al., 2020) found a lack of clarity leads to large fluctuations in results. A method for increasing the accuracy of the metric, namely higher inclusivity of costs even if transferred from another source was suggested. Studies have also shown that the highest drivers of LCoE are typically financing, system costs, lifetime and loan term length (Brankler, et al., 2011).

A common argument made here by (Ueckerdt, et al., 2013) is that LCoE is not well adapted to the inconsistency of VRE generation, which is often misaligned with demand, disrupting the value of energy. Integration and balancing costs are often not included and have real-life significance on results that are often ignored, resulting in higher costs when projects are grid-connected. These can also add carbon to the energy mix, often from dispatchable gas generators. At higher wind shares, these integration costs can be in the same order of magnitude as the generation costs of wind and conventional power plants. The study presented a more accurate metric based on economic theory that included these costs. This was also found by (Sklar-Chik, et al., 2016) and factors omitted inflation, although future inflation is hard to predict and the discount rate does account for lower future cash flows.

FOW-specific studies give important insights into the key drivers and sensitivities, for example the balance between higher CAPEX and stronger wind resources. A comprehensive LCoE study by (Myhr, et al., 2014) across the main FOW concepts of spar, TLP, and semi-submersible designs. Results for a 500MW wind farm are compared to a similar system using jacket and monopile foundations. Results confirm that LCoE is highly sensitive to both water depth and distances to shore, with load factor and availability also driving change and is of relevance to the cases presented in this study. Moderate depths of 50-150 m and deployment at scale allows FOW to become competitive with fixed offshore wind, and LCoE increases are slower with increasing depth compared to fixed. LCoE results are wide ranging from 82-326 €/MWh, reflecting the lack of standardisation across designs.

NPV is the difference between the present value of cash inflows and outflows of a project, discounted to present using a discount rate. Negative NPV would indicate a project that is not viable, due to high CAPEX, OPEX or reduced cashflow

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when combined with low windspeeds, low energy prices, or both. A positive NPV indicates a profitable project, where cashflows overcome initial CAPEX spend and ongoing maintenance of the farm within the project lifetime. As NPV discounts cash flows to present, the chosen discount rate of the project, which can be thought of as the financing cost that an investor would expect to receive as a return on investment, has a large impact on the NPV value.

$$NPV = \sum_{t=0}^{n} \frac{CF_t}{(1+r)^t}, \tag{2}$$

with NPV as the sum of all cash flows CF_t from year 0 to year n, assuming r as the discount rate for the project.

IRR is a similar metric to NPV in that it also compares revenues to costs, but it can also be a straightforward decision maker for a project as it does not require an initial assumption on the discount rate. The IRR equals the discount rate where the project NPV is zero, and IRR above the discount rate define a project that yields positive returns for investors over the lifetime of the project, with one below the discount rate indicating unprofitability.

$$0 = \sum_{t=0}^{n} \frac{CF_t}{(1+IRR)^t}, \tag{3}$$

$$IRR = R_1 + \frac{(NPV_1 \cdot (R_2 - R_1))}{(NPV_1 - NPV_2)}, \tag{4}$$

In the above R_1 and R_2 are initial guesses for the IRR, and NPV_1 and NPV_2 represent higher and lower values of NPV, respectively. If the NPV is close to zero, then the IRR is equal to the R_1, and if NPV has not converged close to zero then new rate guesses must be input into the equation.

An economic viability assessment of FOW by (Castro-Santos, et al., 2020) used three platform technologies in Portugal with another multi-phased site selection method of geographical, economic, and restrictive phases. Two electricity tariffs affected Net Present Value and IRR, with LCoE derived from CAPEX and wind resource. Results again show large variation across different platforms with 289.49€/MWh, 303.97€/MWh, and 325.64€/MWh for spar, semi-sub and TLP platforms respectively. Tariffs of 200€/MWh do not yield positive results for NPV and IRR, with 300€/MWh leading to positive results. This raises the necessity of policy support for FOW deployment which, in turn, will enable economies of scale and supply chain maturity.

2 Method

2.1 Techno-economic model

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Table 1 - Wind farm and general site characterics

Name	Symbol	Units	Near	Mid	Far
Farm size	-	MW	1005	1005	1005
Turbine rating	-	MW	15	15	15
Number of turbines	-	-	67	67	67
Lifetime	-	years	30	30	30
Discount rate	r	%	8	8	8
Avg. exp. cable distance	-	km	33	56	78
Avg. port distance to shore	-	km	49	70	91
Avg. wind speed (10m)	U_{10m}	m/s	6.40	6.69	6.84
Avg. wind speed (150m)	U_{HH}	m/s	8.03	8.42	8.62
Avg. sign. wave height	Hs	m	1.93	2.07	2.13

A techno-economic model (TEM) was developed to provide a detailed cost-generation assessment of floating wind farms at a range of offshore sites in Portugal, with results expressed in terms of LCoE, NPV and IRR. A process flow of the time series data feeding the model, and the model itself can be seen in Figure 1. The TEM takes hourly wind speed data and converts to generation and revenue. OPEX, CAPEX, and DECEX were calculated based on farm scale and affected the three financial metric calculations to assess each location's economic and technical potential. This method was applied to twelve locations, each at three distances to shore, to provide a comprehensive feasibility study for the whole of Portugal. The model considers the distance to shore and its impact on distance-sensitive CAPEX and OPEX change to reflect varying site metocean severity.

For consistency, each location was maintained at 1,005MW (~1GW) installed capacity, using 15MW turbines at a 150m hub height. A 1GW farm size was chosen to reflect the commercial scale of floating offshore wind, as current active leasing areas are generally of this scale or larger, with the initial three leasing zones of 0.5, 1, and 2 GW (Anon., 2023). Locations were chosen to represent the full coastline of Portugal and were not selected based on existing leasing zones or designated offshore development areas, but rather on sites that demonstrate sufficient potential and practicality to support suitable installation and O&M bases for the FOW farms.

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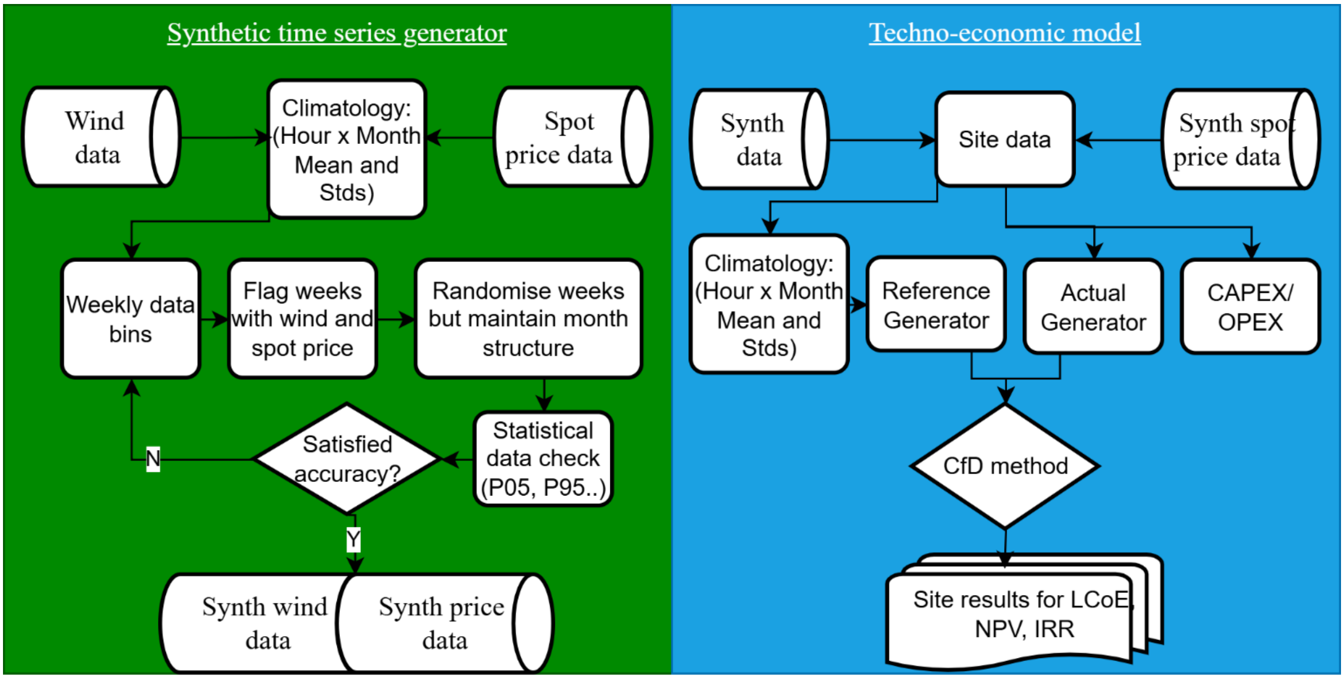

Figure 1 - Flowchart for synthetic time series generator and techno-economic model

2.1.1 CAPEX

Capital expenditure (CAPEX) is based on a reference report: Guide to a Floating Offshore Wind Farm (BVG Associates, 2025). This considers price shocks to raw materials that Europe has experienced in recent years and includes final decommissioning expenses (DECEX), giving a current assessment of FOW expenditure. Costs affected by distance, mainly mooring lines and export cables, were split into per unit of distance values and then re-calculated to reflect the water depth and distance to shore for all sites. A conversion of 3.98 on average was applied to depth to reflect the catenary configuration of the mooring lines. All costs were adjusted to 2024 Euros.

2.1.2 OPEX

OPEX listed above is calculated in two stages using the distance and site severity method as described in (National Renewable Energy Laboratory (NREL), 2016). First, the site metocean data are scaled into three scenarios: a mild site with mean significant wave height (Hs) under 0.88m; a moderate site between 0.88m and 2.5m; and a severe site above 2.5m. These scenarios establish an OPEX cost per kW of installed capacity per year based on the distance to shore and the wave climate, and can be represented as a set of natural logarithm equations defined by (National Renewable Energy Laboratory (NREL), 2016):

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$$OPEX\left(\frac{\frac{€}{kW}}{yr}\right) = \frac{\begin{Bmatrix} 6.0992\cdot\log dTP + 38.127, Hs < 0.88 \\ 4.5907\cdot\log dTP + 48.827, 0.88 \geq Hs < 2.5 \\ 4.0739\cdot\log dTP + 76.993, Hs \geq 2.5 \end{Bmatrix}\cdot conv_{\$€}\cdot\frac{CPI_{FID}}{CPI_{orig}}}{600\cdot 1000}, \tag{5}$$

With Hs the mean wave height at site, measured over 30 years of hindcast data, dTP the distance from site to O&M port in km, $conv_{\$€}$ the conversion rate at the year of reference publication, CPI_{FID} the consumer price index at desired project FID for this study, and CPI_{orig} the CPI at the time of reference publication. The farm size in the original equations, 600 MW, can then be extrapolated to the project capacity of 1,005 MW. Once classified, a learning rate discount is applied to OPEX (National Renewable Energy Laboratory (NREL), 2019), countered by an inflation adjustment over the same period to achieve a realistic value for project FID.

2.1.3 Revenue calculation

2.1.3.1 Spot prices

For the spot price data, a data set was created that is representative for Portugal as a whole, the process for which can be seen in Figure 1. The week-to-week price shape is maintained by using sampled weeks from the original wind data. Price climatology and anomalies are established as before. A quantile map aligns the synthetic price distribution to history, with 200 percentiles of the current synthetic base prices, and the original historic price data. A linear interpolation then preserves the shape and rank per hour and matches to the statistical distribution of historical price data.

Synthetic spot prices form the base layer of cost revenues for each project and provide income to each farm when a CfD mechanism is not in place, which in most cases is after 15 years of operation. No inflation or adjustments are made to the synthetic data, except under sensitivity analysis.

2.1.3.2 CfD support mechanisms

Alongside spot prices, a traditional generation-based CfD was added which provides a stable price for the wind farm, but is dependent on generation where, in low windspeed hours, revenue suffers. The total hourly revenue for a two-way settlement (support and payback) is:

$$CfD_{trad_t} = G_t \cdot P_t + \ (S - P_t)\ G_t, \tag{6}$$

with S the strike price, P_t the reference electricity price, and G_t the actual metered generation at hour t. Settlement is against an ex-ante reference volume instead of actual farm generation.

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For the generation-independent CfDs, the financial version gives stable revenues that separate payments from actual farm generation. Revenues depend on deviations between actual and reference generation profiles, with the net hourly reference revenue being:

$$CfD_{fin_t} = S \cdot MW_{farm} + (G_t - Q_t) \cdot P_t, \quad (7)$$

with Q_t the reference volume and MW_{farm} the rated capacity of the wind farm in MW.

The capability CfD rewards available generation capability instead of delivered energy. Compensations are made to the generator based on availability adjusted potential generation, with hourly payments:

$$CfD_{cap_t} = (S - P_t) \cdot Q_{cap_t}, \quad (8)$$

with Q_{cap_t} the capability generation, based on expected capacity from a fleet and actual capacity of the wind farm in question.

2.1.4 Time series synthesis

The model also contains a timeseries generator, which creates random timeseries for both windspeed and spot price data, and respects the statistical properties of the original. A method was suggested by (Wan, et al., 2013) which utilises climatology and the statistical nature of actual time series data to reliably produce a synthetic future set. Seasonality is maintained alongside diurnal patterns. Mean, median, and P10 and P90 heads and tails are kept as close to the original data as possible. The data is split into weekly blocks where wind and price data overlap, where the shape of the week is intact whilst randomizing the weekly order to create new data for analysis.

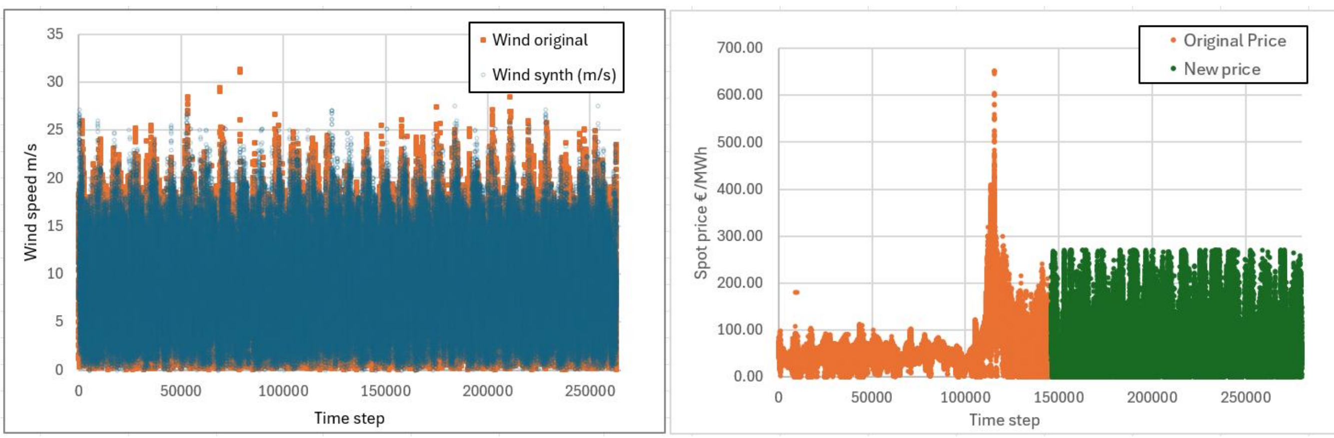

Figure 2 – Synthetic time series generator of actual historical data and future synthetic values

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2.2 Case study

The model was applied to a case study, considering the extent of the Portuguese coastline split into 36 zones. The sites considered are shown in Figure 3, along with windspeed data from the Global Wind Atlas[1], depth contours from the GEBCO database[2], and the most recent lease areas identified by the Portuguese Government[3].

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2.2.1 Wind data

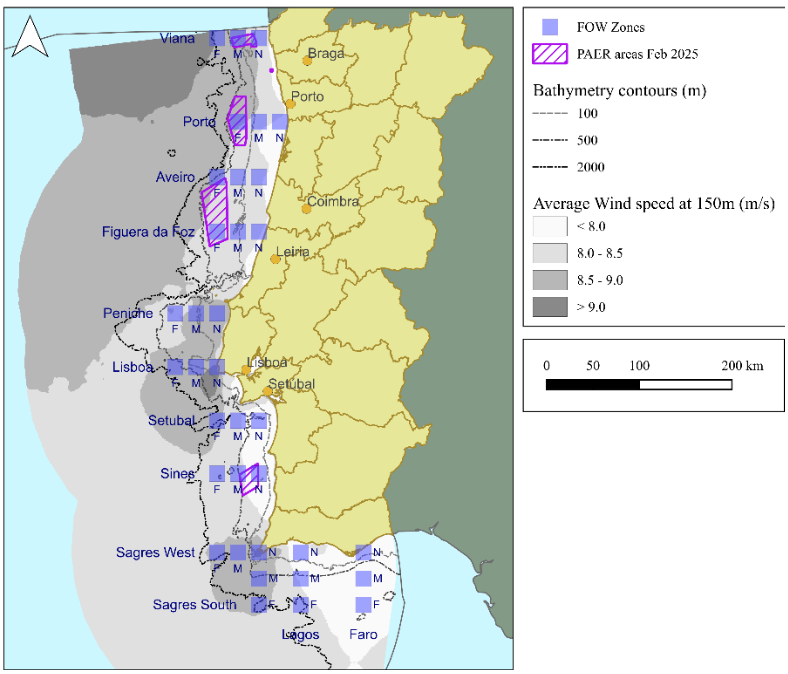

Figure 3 - Map of Portugal showing the chosen sites, leasing rounds, bathymetry and average 150m annual wind speeds (DTU, 2025).

[1] Global Wind Atlas - https://globalwindatlas.info/en/. Last accessed 30.09.2025
[2] GEBCO Database - https://www.gebco.net/. Last accessed 22.09.2025
[3] Portugal Offshore leasing areas - https://webgis.dgrm.mm.gov.pt/portal/apps/webappviewer/index.html?id=9ea76f6fe4ca463a8ced196e30fcc2e1. Last accessed 29.10.2025.

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A 30-year hourly hindcast dataset was generated from (Lautec, 2024) which accesses the European Centre for Medium-Range Weather Forecasts (ECMWF) ERA5 dataset, as has been used for similar studies including (Molina, et al., 2020). Generation and OPEX run for a base length of 30 years, confirmed with recent leasing rounds in the UK now allowing 60 years of operation (two cycle) (The Crown Estate, 2024). Datapoints provide wind speed data at 10m and 100m, plus significant wave height and wave period and are selected from a latitude-longitude gridded dataset at a 0.25º resolution. Figure 3 shows the three datapoints for each site at increasing distances from shore. Of interest are the higher windspeeds to the North, and close to the capes of Roca (north of Lisbon) and São Vicente (Sagres) creating higher wind speeds due to the wind gradient and funnelling effects of inland winds reaching the lower friction surface at sea. To reflect higher wind speeds experienced at the turbine nacelle, 10m above sea level measurements were extrapolated to a hub height of 150m using the power law equation:

$$U_z = U_{ref}(\frac{z}{z_{ref}})^{\alpha}, \qquad (9)$$

Here U_z is the wind speed in m/s at height z, U_{ref} the reference wind speed from the data set, z_{ref} is the reference height in m, α is the exponent factor that relates to the atmospheric stability (Touma, 1977), with a value of 0.11 used to reflect deep water offshore locations as recommended in IEC standard IEC 61400-3: and consistent with the findings of (Yang, et al., 2024.).

For the data synthesis, an hourly climatology of average and standard deviation across thirty years per site was created. Anomalies are then established as the difference per hour between the site wind speed measurement and mean climatology value over thirty years. Anomalies are then re-added to the synthetic time series to preserve the temporal correlation and wind-price alignment, alongside monthly and diurnal cycles.

2.2.2 Generation

Once the wind resource is defined at hub-height, the kinetic energy contained in the wind is transformed into electrical power through the turbine's aerodynamic and electromechanical processes. This is done by creating a power curve using the exponential parameters of a curve fitted to the 15MW wind turbine generator (WTG) parameters and wind speed

$$P_U(kW) = A \cdot (1 - e^{(-k \cdot U_z{}^n)}) \qquad (10)$$

With P_U the power at wind speed U, A the WTG rated power in kW, k, n are fitting constants that are adjusted and optimised in the model to reduce the sum squared errors (SSEs) between the actual power curve and the modelled power curve produced with Eq. 10. This equation allows the hourly averaged wind speed data to be converted at a higher temporal resolution with regards to distributional probability methods with mean annual values. Constraints can also then be applied to produce no power at wind speeds below cut in and above cut out speeds (set at 3m/s and 25m/s respectively).

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Farm generation is the individual energy production from one WTG scaled to the farm level, with reductions applied for wake effects and electrical losses, and with availability applied last. The scope of this study is not the optimisation of farm using detailed wake models and layouts, and therefore a simple grid was used for layouts and turbine spacing. However, this aspect serves as a potential avenue for future work.

$$E_{farm}(kWh) = P_U \cdot n_{WTGs} \cdot (1 - \eta_{wake} - \eta_{elec}) \cdot avail \tag{11}$$

E_{farm} is the total energy output of the wind farm in kWh for one hour, n_{WTGs} the total number of WTGs in the farm, η_{wake} the wake losses, η_{elec} the electrical losses, and $avail$ the total farm availability. This is then summed over the lifetime to obtain total energy.

3 Results

3.1 LCoE

LCoE results were mapped according to the latitude and longitude of each prospective wind farm location. Figure 4 presents these results, along with mean wind speed at the hub height of a 15 MW wind turbine and the depth contours, alongside leasing areas. Due to the impacts of longer cable routes and sea depths, sites closest to shore tend to be the most desirable from an LCoE perspective. This is especially true for sites to the South, where lower wind speeds further reduce the benefit of far sites. In the North, far sites are preferable due to improved wind speeds, with some above 9.0m/s. Also shown are the current leasing zones associated with Portugal's floating offshore wind auctions, to contextualize the results within the present development landscape. Geographical features including Sintra peninsular off Lisbon and also in the Southwest, Sagres zones also benefit from improved but local windspeeds. Also, larger areas of shallow shelf see consistent LCoE, especially zone B in Figure 4.

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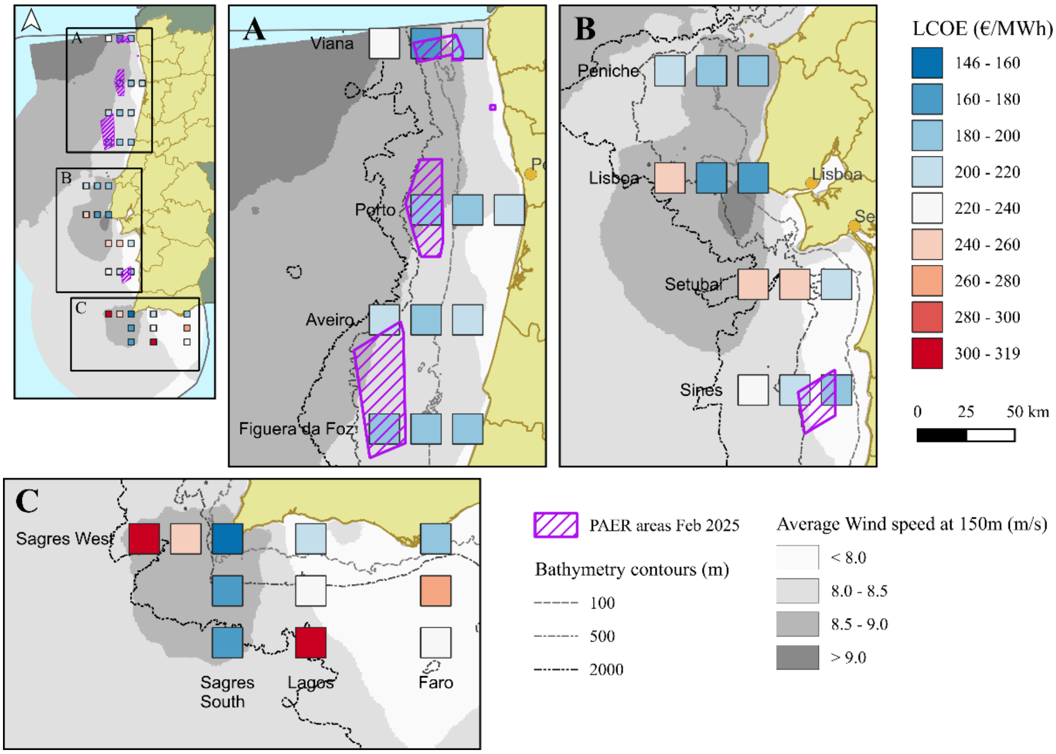

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Figure 4 - Mapped LCoE results, with mean wind speed and depth layers

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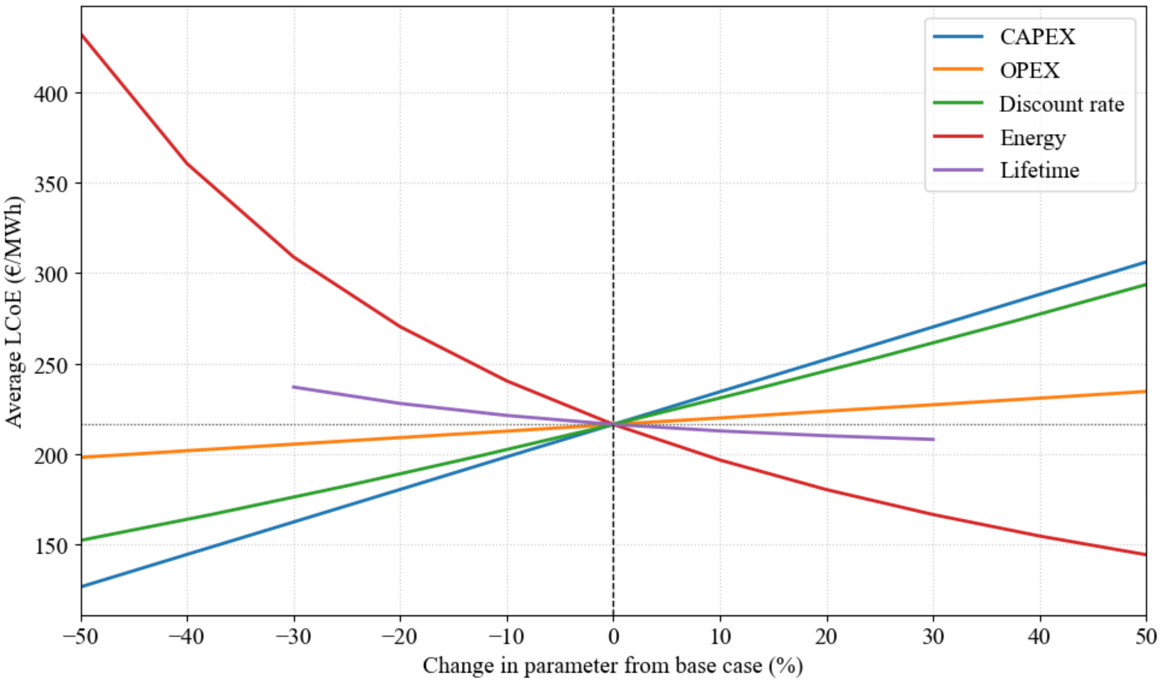

Figure 5 - LCoE Sensitivity Analysis across main parameters, averaged across all sites

Figure 5 presents sensitivity analysis for the key parameters with influence over LCoE, ranging ±50% from base case, and averaged across all sites. Steeper gradients represent larger effects on LCoE, which is highest for changes in energy generation, followed by CAPEX and discount rate. Energy change is significant as there is on average a 7% rise in wind speed moving from near to far sites, but this must be tempered by the longer export cable routes and steep increases in water depths.

In this study, CAPEX is spread across the years leading up to the project and so is negatively discounted which raises costs. This represents a more realistic approach to FOW purchasing, as consolidating all procurement in the year before generation would be impractical. CAPEX adjustment from 50%-150% of total expenditure, alongside energy generation, has the greatest impact on LCoE. 50% of total CAPEX would require dramatic cost reductions especially to the heaviest and material intensive components such as platforms and mooring systems in deeper waters (Barter, et al., 2020). 150% CAPEX is also a potential risk, considering changes to commodity markets that have in some cases doubled in recent years. At 50%, LCoE range is narrower, between 88-183€/MWh and with the distance-based costs not being as impacted by smaller costs. At baseline, LCoE is between 150-326€/MWh and at 150% CAPEX it ranges from 183-469€/MWh. As this result range reflects the LCoE of some of the best performing offshore wind farms in operation to LCoE that initial demonstrator or pre-commercial arrays may experience, efficiency in component fabrication, selection and improving all project phases leading up to FID are of critical importance.

The discount rate also has high impact on results and project feasibility and therefore a realistic value and sensitivity range should be set, owing to the larger impact on generating, O&M, and any CAPEX not undiscounted at year 0. The base

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value of 8% represents riskier technology in a challenging environment and 2% above normal fixed offshore wind, which is currently the rate for most wind farms built and operated in mature markets (Malleret, et al., 2024).

For OPEX, around one third of total project expenditure is attributed to the operating and maintenance of the FOW farm. As OPEX is discounted over time, this results in ever reducing costs over the project life. Most sites are classed "severe" due to wave heights and the classification method explained in Section 2.1.2. OPEX adjustments maintain a relatively low impact to LCoE. It is impacted with increasing distance, but most sites fall into the 25-100km (severe) or 25-150km (moderate) bands that define a medium-distance strategy and therefore moderate cost impact.

General LCoE results across all sites are found in Figure 6, with the average across all sites and distances shown for reference. Northerly and Southerly sites vary most with increasing depths, where better wind speeds are not enough to offset the longer cable routes and O&M expenses. The flatter and larger shelf area North of Lisbon benefits sites such as Peniche, Porto, Aveiro and Figuera, where mooring costs are not so extensive and present more room and shallower water for deployment, in line with the proposed deployment areas shown in sectors A and B of Figure 4.

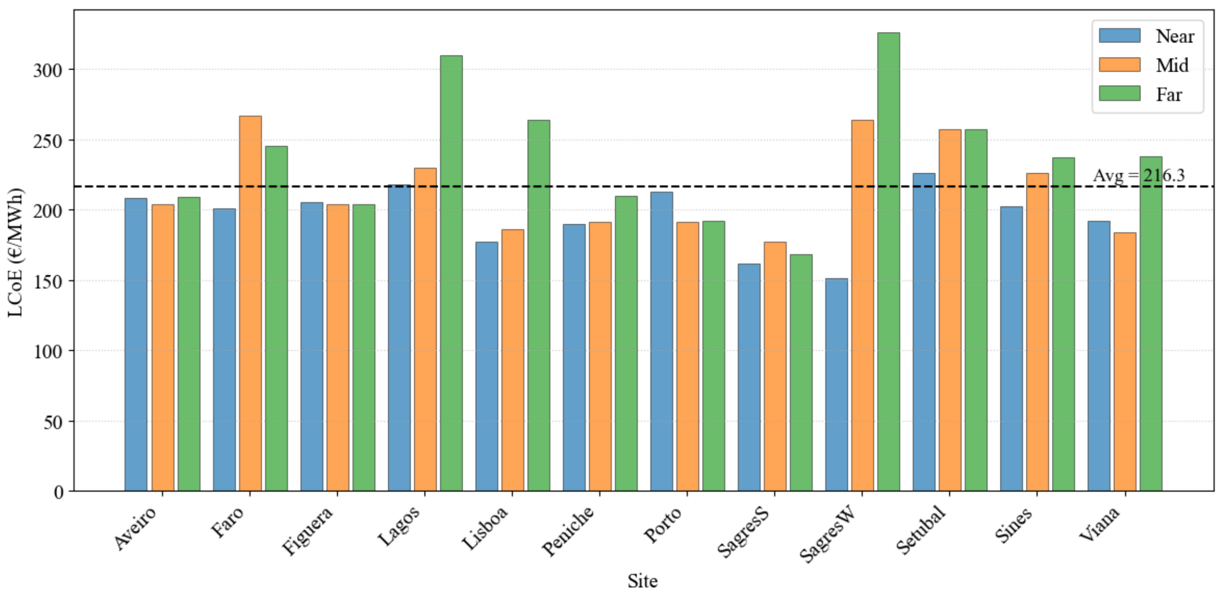

Figure 6 - LCoE results per site and distance to shore

3.2 NPV

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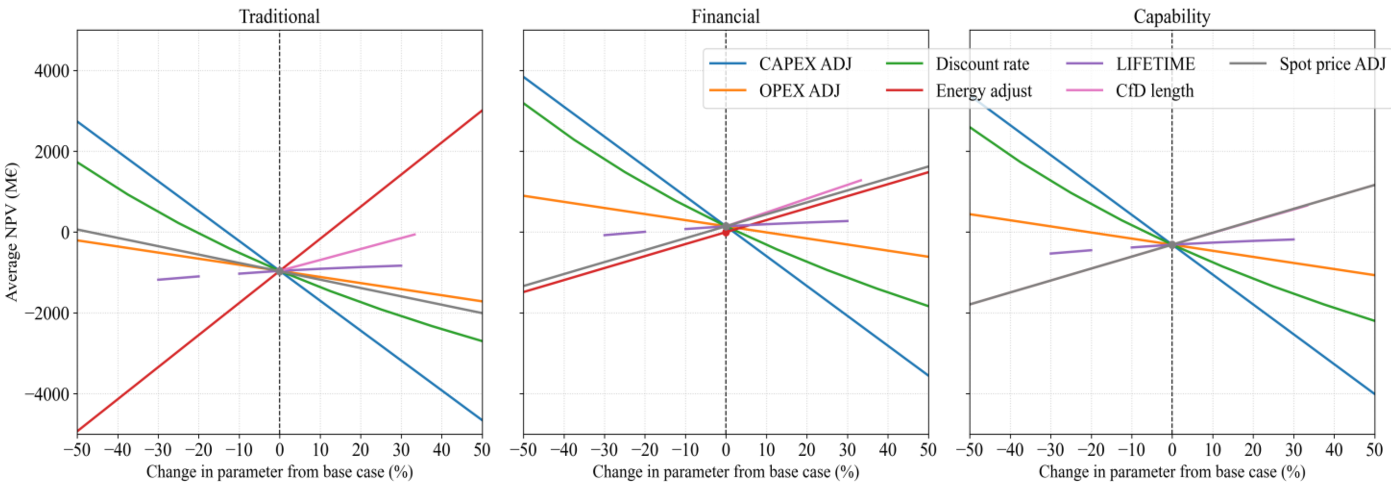

Figure 7 – Sensitivity analysis results for NPV for Traditional, Financial, and Capability CfD

Sensitivity analysis for NPV is shown in Figure 7 with changes to key parameters. As expected, energy adjustment has a large impact on the traditional CfD type, which is the only truly generation-dependent method. CAPEX and financing costs are also high drivers, which highlight the need for de-risking and cost reductions in FOW for commercialisation to become a reality.

Project balance for a range of wind farm locations, closely linked to the prospective leasing areas, are shown in Figure 8. Almost all traditional CfD methods with a €250/MWh price do not make profitability within 30 years of base case operation. The steeper part of the upward curve after the CAPEX debt represents the CfD, and the financial and capability methods almost all result in wind farm profitability before the regular spot prices come into effect from year 15 onwards.

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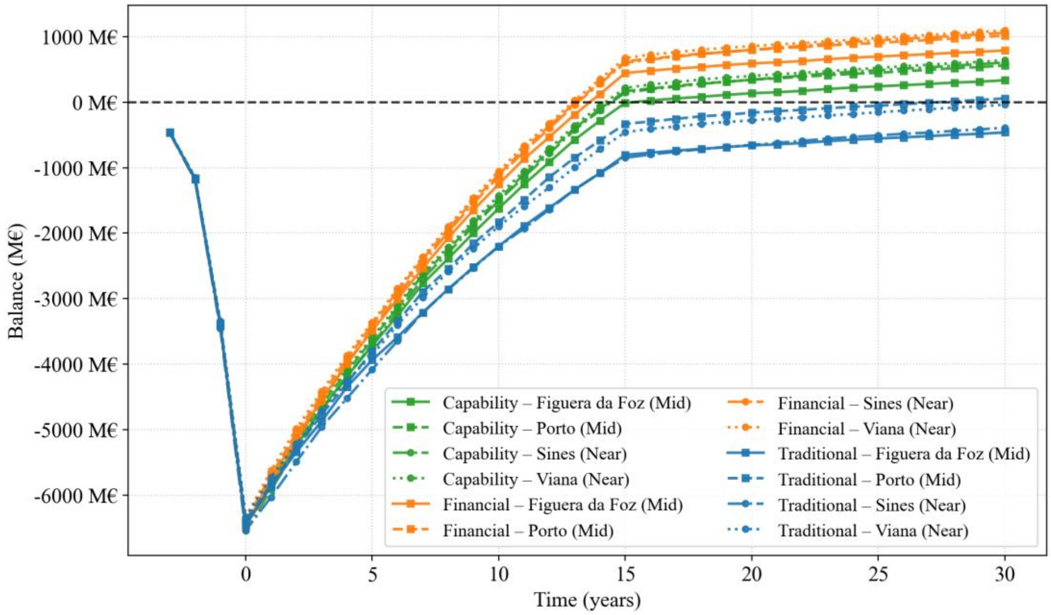

Figure 8 - Project balance for a range of Portuguese wind farm locations

3.3 IRR

Geospatial IRR results under a Traditional CfD are presented in Figure 9. This defines a commercial farm but with added risk compared to fixed offshore wind; any IRR value under 8% represents a currently unprofitable wind farm area. Wind speeds at hub height and significant depth contours are also shown. Coastal areas under a traditional CfD are profitable in the Southwest Sagres area only, due to the lower export cable routes, O&M distances and higher wind speeds local to the Sagres peninsula. Under traditional CfD revenues, which are dependent on farm generation and not helped by a fleet average, only a selected few sites would be viable under the current economic conditions (considering an 8% hurdle rate).

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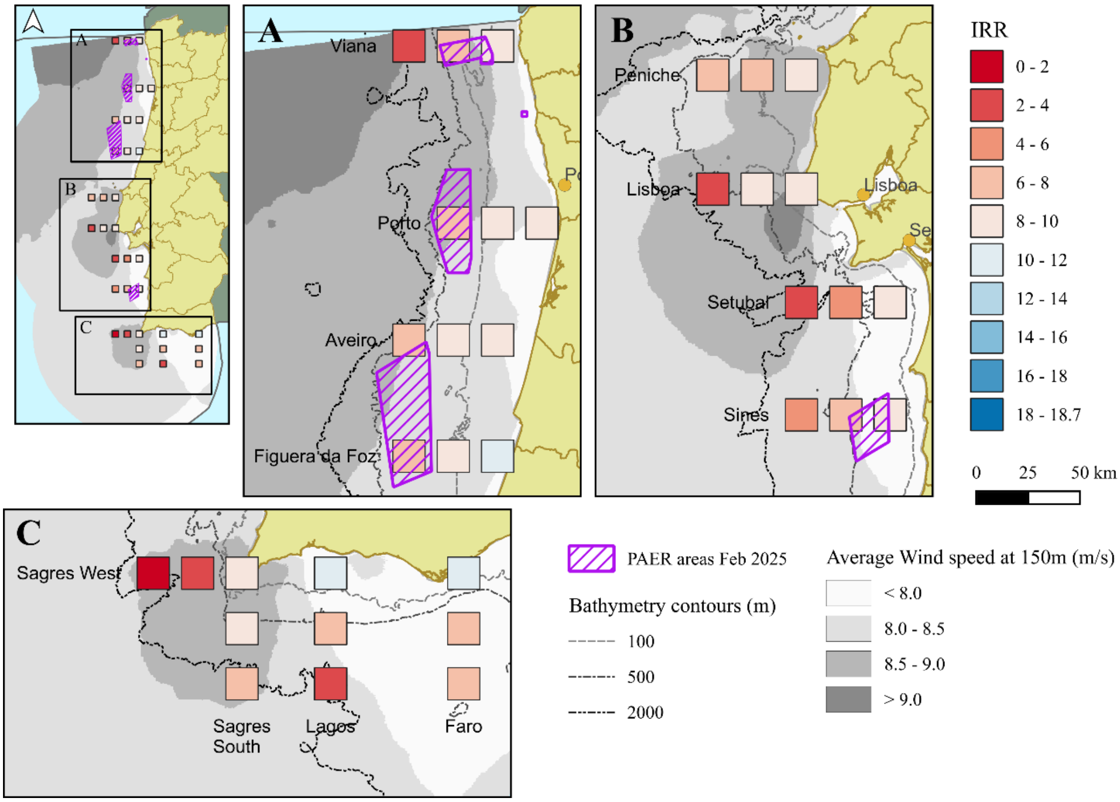

Figure 9 – Mapped IRR results for Traditional CfD, with mean wind speed, leasing zones and depth layers

The generational-independent revenue support schemes are presented in Figure 10, along with the IRR delta compared to the traditional generation-based CfD method. The capacity method provides the best results, which provides consistent revenues across the CfD lifetime, set at 15 years for the base case. All but two near coastal sites are now viable under the financial CfD method, which is set at 100€/MWh reference generation for the first 15 years of operation. Far-shore sites are still unprofitable around Lisbon and South towards Sagres owing to the challenging distance both to shore and to the seabed.

For the capability method, improvements are still visible and again only two coastal sites are not profitable under these conditions. The Capability method is set at 250€/MWh capability payment base which would come at considerable financial expense to the sponsor, but does result in profitable outcomes for the majority sites, especially West-facing near and mid zones.

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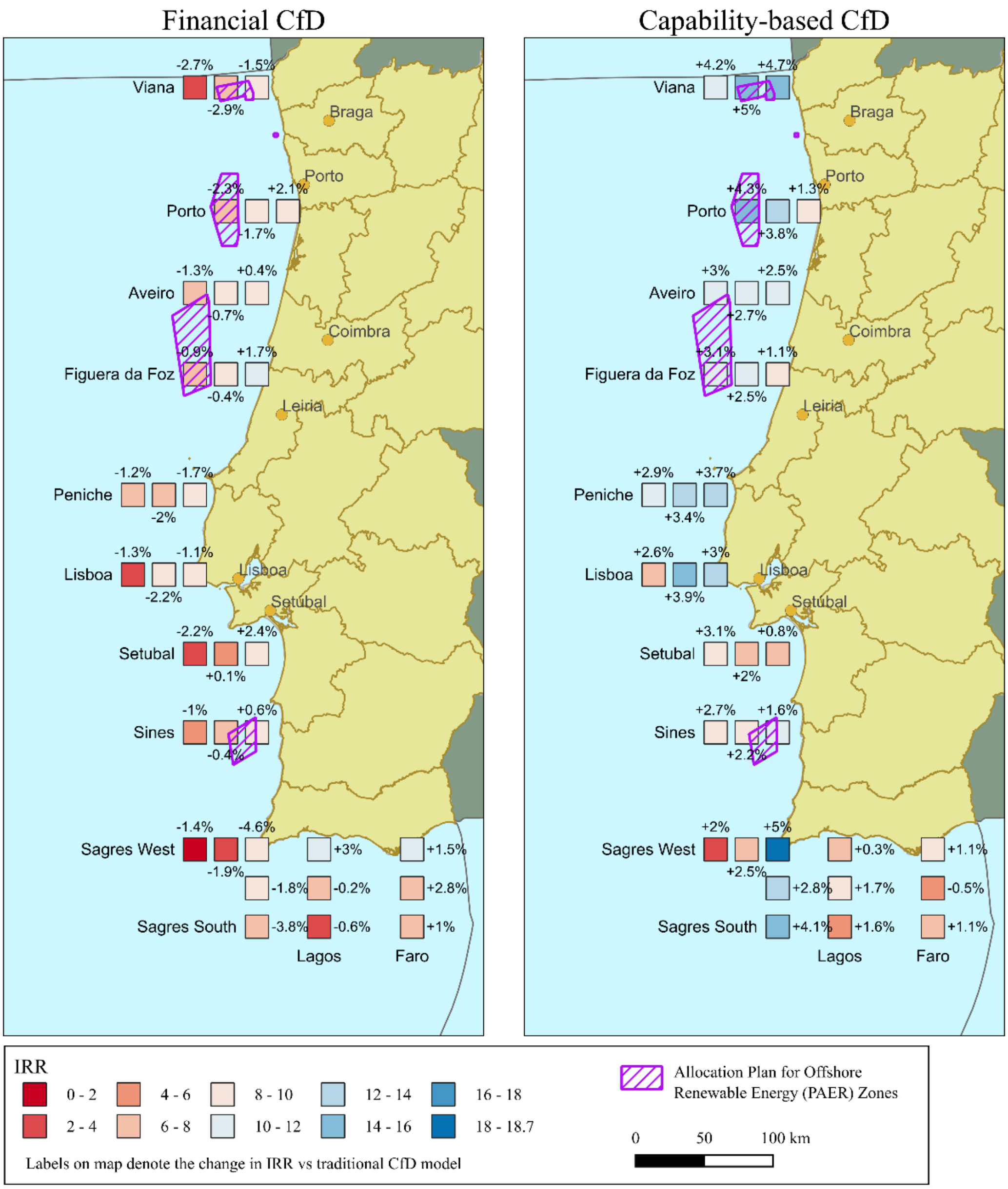

Figure 10 – Mapped IRR results for generation-independent Financial and Capability CfDs

370 **4 Conclusions**

This paper shows that floating offshore wind is economically viable in Portugal, but only under specific financial conditions. Under a traditional CfD approach, only near-shore coastal sites are viable given current CAPEX levels and expected project financing terms. Under generation-independent CfD schemes, where remuneration is based on reference generators or installed capacity rather then actual output, most near-shore sites become viable at a spot price of €100-250/MWh for a 15-year contract. Sensitivity analysis shows that CAPEX, energy yield, and discount rate are the most potent drivers of changes in LCoE, IRR and NPV, and therefore represent the principal barriers to be addressed for floating offshore wind to progress from its current pre-commercial scale o full commercial deployment, with the associated climate and socio-economic benefits this expansion would enable. Although the present analysis does not evaluate wider industrial or market-evolution effects, as global costs fall and domestic supply chains mature, floating offshore wind has the potential to move from a challenging investment today to a major long-term economic and strategic opportunity for Portugal.

5 Author contribution

Craig White: Study conception; techno-economic model development, simulations, results analysis, writing.

Ciaran Frost: GIS mapping, manuscript review, editing.

José Cândido: Manuscript review, editing.

6 Competing Interests

"The authors declare that they have no conflict of interest.".

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