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Macroeconomic impact on the risk management of offshore wind farms

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ABSTRACT

The present study aims to develop a risk model to analyse offshore wind projects based on operational and macroeconomic data. The study investigates the underlying parameters defining the project-specific risk premium attached to an offshore wind project. These parameters are modelled as stochastic variables, and a probabilistic financial analysis is conducted using Monte Carlo Simulation. To calculate an interest rate based on operational characteristics, the present study assumes that two net present value equations yielding the same result can be written where certainty equivalent cash flows discounted at the risk-free rate and b) expected cash flows discounted at the cost of capital. The project-related risk is then estimated by solving the resulting equation for the unknown cost of capital. The macroeconomic factors are also considered as they impact the uncertainty associated with revenue and operating expenditure. The model developed to calculate the cost of capital is validated by comparing it with the data obtained for publicly traded renewable energy companies worldwide. Finally, the developed model is demonstrated for a fictitious ageing offshore wind farm under different economic circumstances. The parametric study is conducted on the effect of critical project-specific parameters such as the number of offshore wind turbines, the life extension duration, and the degree of uncertainty related to cash flows.

1. Introduction

For offshore wind to be a competitive energy resource without states' incentives, investment decisions in offshore wind projects must be made based on rigorous analysis of the expected economic benefits and the risk associated with getting these economic benefits. Whether the economic benefit of an offshore wind project is modelled as net present value, return on capital, internal rate of return or economic added value, the risk of a prospective project is usually represented by a discount rate that reflects the time value of money, i.e., opportunity cost.

The discount rate accounts for the risk-free rate, the project's financial structure, and last but not least, the project-specific risk premium. In corporate finance, the discount (hurdle) rate is estimated based on confidence in achieving the project's rate of return. In this context, the present work develops a risk modelling framework based on the uncertainties associated with revenue and operating expenditure to estimate the project-specific risk. The project-specific risk is represented in the form of the relative risk measure that can be implemented within the capital asset pricing (CAPM) theory so that the model developed here can be generalisable to other offshore wind projects across the world. The outcome of the present study can help decision-making in offshore wind projects under uncertainty and could be used as a risk-based asset management tool.

Historically the progress in the capacity factor and the low-interest rate environment have been the biggest contributor to the low cost of energy (Voormolen et al., 2016). Also, the financial attractiveness of offshore wind projects is increased even though there is a considerable increase in capital expenditure due to developing offshore wind farms (OWF) in deeper waters and more distant from shore (Prässler and Schaechtele, 2012). However, this reduction has not been at the same rate in the countries heavily invested in offshore wind, such as the United Kingdom, Germany, and Denmark. For instance, Voormolen et al. (2016) suggested that location-driven factors, commodity prices, and the discount rate affect capital expenditure differently, in turn, levelised cost of energy (LCoE). Prässler and Schaechtele (2012) argued that energy policymakers have a direct impact through financial support schemes and an indirect impact on cost structure through regulations related to grid connection and agreements with the fishing industry.

It can be argued that labour cost and competition intensity can also contribute to such differences in the financial attractiveness of offshore wind projects influencing the risk appetite of private and institutional

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Nomenclature

OWT	Offshore Wind Turbine
OWF	Offshore Wind Farm
CAPM	Capital Asset Pricing Model
CAPEX	CAPital EXpenditure
OPEX	OPerational EXpenditure
LCoE	Levelised Cost of Energy
O&M	Operation and Maintenance
DFC	Discounted Cash Flow
nOWT	number of Offshore Wind Turbine
CoV	Coefficient of Variation
var	variance
WACC	Weighted Cost of Capital
MWh	Megawatt-hour
AEP	Annual energy production
WH	Working hours
RP	Rated power of the wind turbine
rMar	Ratio of Marginal Investor
CF	Capacity factor
AV	Availability
CR	Currency
FiT	Feed-in tariff
ROCE	Return on capital employed
g	projected perpetual growth rate
r_f	Risk-free rate
r_e	Cost of equity
r_d	Cost of debt
r_c	Cost of capital
$\beta_{unlevered}$	Unlevered relative risk measure
$\beta_{levered}$	Levered relative risk measure
$\beta_{business}$	Relative risk measure related to business
$\beta_{project}$	Relative risk measure related to project
$r_{inf,\ demand}$	Rate of inflation on the demand side
$r_{inf,\ supply}$	Rate of inflation on the supply side
σ_{asset}	Standard deviation in asset price
σ_{market}	Standard deviation in the market
$\rho_{asset,market}$	Correlation between the asset and the market
ρ_{sector}	Correlation between the sector and the market
$\mathrm{E}[CF_i]$	Expected cash flow at year i
$CECF_i$	Certainty equivalent cash flow at year i
ΔDCF	Difference between total $\mathrm{E}[CF]$ and $CECF$
ERP_{mature}	Equity risk premium for the mature market
σ_{equity}	Standard deviation in the equity market
σ_{bond}	Standard deviation in the bond market
CRP	Country risk premium
ICR	Interest coverage ratio
EBIT	Earning before interest and taxes

investors being more active in offshore wind projects. More details can be found on the economics of offshore wind in (Green and Vasilakos, 2011), historical cost developments in (Vieira et al., 2019), and future economic perspectives in (Beiter et al., 2020; Blickwedel et al., 2021; Zwarteveen and Angus, 2022).

Liu et al. (2021) classified decision-making approaches in offshore wind power investments as basic methods (discounted cash flow, life cycle assessment), advanced methods (levelised cost of energy, cost-benefit analysis), probabilistic methods (real options theory, Monte Carlo simulation, modern portfolio theory, stochastic optimisation) and multi-criteria methods (data envelopment analysis, multi-criteria decision making). Although the line separating basic and advanced methods is somewhat obscure, the review Liu et al. (2021) argued that accounting for uncertainty and all life-cycle phases is the key to sophisticated decision-making.

In the present study, this view is acknowledged and even taken further to claim that the key to any good investment decision can be boiled down to the accurate reading of the risk-return relationship because, ultimately, what matters more is a relative valuation (comparison between risk and return) rather than an absolute value of the return. Therefore, it makes relatively little difference whether the performance indicator is the net present value (Shrieves and Wachowicz, 2001), economic added value, discounted cash flow, internal rate of return, levelised cost of energy (Johnston et al., 2020) or carbon emission, real option value (Lee, 2011) or Sharpe ratio (Yeter et al., 2022).

It is worth mentioning that the view given above does not encourage reductionism; instead, it encourages careful and detailed scrutiny of revenue, operating expenses, corresponding uncertainties, side benefits, and opportunity costs. Moreover, side benefits and opportunity costs are rarely mentioned but are equally important to the terms of the financial statements. Weaver (2012) also advocated that risk-based returns are not the only investment criterion in today's offshore wind investment landscape, and investors have engaged in projects incorporating social and environmental initiatives. Nevertheless, one can still argue that an investment decision-making problem can be formulated, including all the cost and benefit components, as long as the variables are scrutinised and the model is internally consistent, which is covered by a risk-based analysis.

In terms of the risk in offshore wind projects and the relevant methods to manage the risk, the works of Ioannou et al. (2017a), Gatzert and Kosub (2016) and Abba et al. (2022) stood out in the literature. Ioannou et al. (2017a) stated that the risk in renewable energy investment is multifactorial and categorised using a political, economic, social, technology, legal and environmental (PESTLE) approach (Kolios et al., 2016). These factors gain importance depending on stakeholders' perspectives. The present study focuses on the risk factors that are more relevant for project developers and investors; however, the risk factors associated with other stakeholders such as insurers, manufacturers, consumers, affected local communities, and policymakers can be considered with an appropriate weighting factor.

There is a vast literature regarding financial appraisal of offshore wind projects majority of which is conducted deterministically. However, as a result of accumulated knowledge, available operational data, and enhanced computational capacity, there is a growing interest in stochastic simulations encapsulating all major factors influencing revenue (wind farm layout (Ali et al., 2013; Ali et al., 2012), wind speed (Mora et al., 2019), losses (Wilkie and Galasso, 2020, 2022), structural condition of blades (Staffell and Green, 2014), curtailment (Burke and Malley, 2011), energy market prices (Haji Bashi et al., 2016; Ioannou et al., 2018, 2020)) and costs (fixed and variable O&M (Heck et al., 2016; Kerres et al., 2015; Papadopoulos et al., 2022; Rinaldi et al., 2021; Tran and Smith, 2018), weather (Ioannou et al., 2020; Judge et al., 2019), insurance (Ioannou et al., 2017b), inflation rate (Ioannou et al., 2018, 2020)).

The success of a financial appraisal of offshore wind projects relies on an accurate definition of the revenue and cost drivers as well as the stakeholders involved in an offshore wind farm operation. In this regard, it is critical to consider risk premiums associated with macroeconomic, microeconomic and financial structure-related (Angelopoulos et al., 2017) as well as investor-specific project risk (Salm, 2018). Moreover, an alternative to the computationally expensive simulations to estimate operational expenses, parametric equations can be derived from the literature and, if available, from the operators' databases, as shown by Maienza et al. (2020) and Castro-Santos et al. (2016).

In light of the literature review above, the present study acknowledges that the uncertainties regarding the cash flow stream and

Table 1
Risk identification for offshore wind projects using the PESTLE approach (Abba et al., 2022; Gatzert and Kosub, 2016; Ioannou et al., 2017a; Kolios et al., 2016).

Risk category	Risk subcategory	Risk factors
Political	Country	Political stability Shift in the government's energy and climate change policy Geopolitical Crises, e.g., war, embargo, currency strength, scarcity in resource supply
	Regulatory	Insufficient or uncertain supporting policy frameworks and incentives, e.g., feed-in-tariff, tax benefits Difficulty in acquiring land or competing with other stakeholders, e.g., the fishing industry, tourism Regulatory limitations in interconnectivity between mini-grids and main grids
Economic	Market	Variability of revenue due to electricity price Variability of revenue due to demand fluctuations Sensitivity of competitiveness of renewable energy to prices of conventional energy sources Risk in speculative markets, e.g., real state (lease) market, equity market, foreign exchange markets Modelling uncertainty regarding future energy prices Sensitivity of market disturbance due to research on competitive technology and application Limited market and consumer data availability Vulnerability to external market volatility due to dependence on imports
	Sales	Risk regarding potential business interruptions, e.g., O&M-related downtime, natural hazard, defective serial assets, grid availability, curtailment Modelling uncertainty regarding resource (wind) and capacity (wind turbine) assessment Risk regarding counterparties' poor credit quality (O&M Supplier and power purchaser) Currency risk resulting in lower-than-expected revenue
	Financial and Fiscal	Involvement and sentiment marginal investors Limited access to affordable capital, e.g., private equity, market equity or debt High initial investment, i.e., CAPEX Poor economic outlook, i.e., recession – Uncertain macroeconomic factors High-interest rates or dramatic changes in interest rates Change in the nature of the product – from non-discretionary to discretionary High operating leverage, i.e., fixed to variable operational cost ratio Suboptimal financial structure, i.e., debt-to-equity ratio Financing or refinancing risk due to a mismatch between short loan terms and project lifetime Limited domestic or foreign investor capital
	Business value proposition	Health and safety concerns damaging reputation
Social	Lack of public acceptance	Public resistance to projects due to mistrust of technology and its constituents affecting policy support schemes Public resistance to projects due to environmental and aesthetic influence delaying construction and licence acquisitions
Technological	Project development and technology qualification	Limited data availability for resource and techno-economic assessment Unexpected delay for commercial operation data due to licencing, clearances, access, weather etc., Failing in technology qualification and certification Reliance on technological development in other life-cycle stages, installation, transportation, etc., Technology progressiveness impacting on efficiency and quality Limitation in skilled labour in manufacture, construction, operations, maintenance, etc.
	Construction	Uncertainty regarding novel design with new manufacturing technologies Reliability of the critical components used in construction, transportation, and installation Uncertainty regarding the material quality Damages occurring during construction
	Operation/maintenance	Damages occurring to physical assets due to negligence, accident, wear and tear Damages due to natural hazards Higher OPEX due to the unavailability of critical components to be replaced Inefficient scheduled maintenance planning Harsh weather conditions Risk of unexpected costly repair actions in inaccessible locations Unprecedented closure of assets due to systematic risk (grid connection lost) Risk of serial losses due to defective components
	Resource risk	Aleatory (natural variability, climate change, etc.) and epistemic (hindcast data) uncertainties in estimating power potential and its variability
	Infrastructure	Risk due to the limitation in grid connectivity, management, and resilience
	End-of-life	Uncertainty regarding decommissioning, repowering, or life-extension costs Life extension certification
Legal	Energy and climate change policy	Risk arising from liabilities to the third party and contracting risks resulting in legal disputes and lower-than-expected revenue Legislative changes and obstacles, bureaucracy, inefficient approval processes resulting in the delay of permits and higher-than-expected expense
Environmental	Environment damage	Natural disasters Carbon footprint and life cycle modelling/assessment

macroeconomic factors are the main drivers of the risk involved in an offshore wind farm project. Thus, the present study aims to contribute to the literature by developing a generalisable risk model for offshore wind projects using operational and macroeconomic data. To this end, the underlying parameters defining the project-specific premium attached to an offshore wind project are investigated. Further, the macroeconomic and microeconomic factors are also considered as they impact the uncertainty associated with the economic benefit. These parameters are modelled as stochastic variables, and a probabilistic financial analysis is conducted using Monte Carlo Simulation. Finally, possible ways to de-risk a life extension of an ageing offshore wind farm under different economic scenarios are discussed, aiming to maximise the economic added value by the project.

2. Risk and risk management in offshore wind projects

2.1. Risk definitions in offshore wind projects

As offshore energy systems become more complex with the inclusion of more stakeholder policymakers and civil society, such analysis requires a more interdisciplinary approach where the insights from each discipline are integrated to develop a more comprehensive risk model of these complex systems. Commercial offshore wind farms are massive investments for any firm in terms of capital, whether public or private. Many stakeholders are involved, directly and indirectly, affecting the risk associated with such ambitious endeavours. The risk involved in such projects can be purely related to the nature of the business or project-specific risks. Such risk can be considered internal, which can be lowered by executing the project at the right site, size, and time with the right recruitment.

Moving on the continuum of risk specificity (project-specific to the market or idiosyncratic risk to systematic risk), besides internal factors, investors should also expect external factors such as political, social, regulatory, and macroeconomic, which can be diversified by taking on more projects globally up to the point of reaching the systematic market risk. All these factors can influence the return on the investment; therefore, it is imperative to identify all relevant risk factors, factor them in a risk assessment based on their criticality and manage the risk by avoiding, transferring, and mitigating.

The present study adopts the PESTLE (political, economic, social, technological, legal and environmental) approach that was demonstrated to be very useful in the risk identification process by Ioannou et al. (2017a) and Kolios et al. (2016). The risk categories, subcategories, and factors for offshore wind projects from the developers' and investors' perspectives are presented in Table 1.

The advantage of viewing an investment from by lenses of multiple stakeholders is that it allows for a more realistic and effective risk management plan providing more resilience to crises driven by factors such as commodity prices, recession, supply-demand disequilibrium, high inflation, and investor sentiment.

It should be noted that developers and investors in each country face these risks differently. For instance, According to Abba et al. (2022), political, regulatory and financial risks have appeared to be a major barrier to renewable energy investments in the United States, France and the United Kingdom, whilst resource variability and infrastructure limitation resulting in curtailment have been seen as a priority. Last but not least, there is a first-mover advantage and a risk; some of the technological and financial risks can be overlooked or accepted due to "intangible" rewards to be collected in the future as a result of evoking innovation and creating new markets for non-consumers of the technology (Christensen et al., 2019).

2.2. Project risk modelling in corporate finance

A risk-return model is a tool that facilitates conducting a cost-benefit analysis of an investment. It utilises an appropriate risk measure for the expected return on investment. The expected return is usually used as a benchmark in the analysis of different projects, i.e., hurdle rate. It is only possible to maximise the long-term value of a business by taking on projects with returns higher than their hurdle rates.

A good risk-return model should be generalisable; provide a rationale for the risk factors included. The risk measure should be comparable with others providing a chance to evaluate different projects from the risk point of view. The risk measure must be convertible to a return measure for compensation. The model should work with historical data and be capable of making future predictions.

The risk can be measured by characteristics of the probability distribution of the actual returns. An investment with a certain return in a short period of time would seem riskless. However, an investment in securities frequently traded in the stock market can have a much different return than expected. Thereby, it can be argued that the difference represents the riskiness of the investment, which is captured by the variance of the actual return distribution. There are other statistical attributes that can reflect the risk in an investment, such as the skewness of a distribution, which shows the bias towards positive or negative, and the kurtosis of a distribution showing the tendency of extreme values in either direction.

In the case of normally distributed returns, variance or standard deviation provides a relative risk measure. It is a common practice to compare the risk of an asset to the market risk that represents non-diversifiable and what a marginal investor holds. By doing so, firm/business/project-specific (idiosyncratic) risk can be distinguished from market risk (systematic risk).

The marginal investor is the type of investor with the most influence on the valuation/price of a tradeable asset, such as large institutional investors. The marginal investor can be a mutual fund, pension fund, sovereign wealth fund and internationally well-diversified. This assumption is particularly important because if the project's investor is not well-diversified, then the expected return, in turn, the hurdle rate must also reflect diversifiable risk. The degree to which the hurdle rate is raised depends on the correlation between the sector and the overall market, which will be discussed in the following section.

2.3. Relative risk measure

Before presenting the details of the risk model, it is essential to lay the groundwork for measuring the relative risk of a company, business, or project. The following three subsections explain how to derive a relative risk measure based on the historical stock prices of a company, the bottom-up approach where the relative business risk measure is estimated using statistical analysis, and the certainty equivalent approach for pure project risk.

The underlying principle behind a relative risk measure is that the risk of any asset to an investor is the risk added by that asset to the investor's overall portfolio or market portfolio, which contains only systematic risk that cannot be diversified away. Statistically, this added risk is measured by the covariance of the asset with the market portfolio, which means assets that move more with the market portfolio tend to be riskier than assets that move less. Once the covariance of the asset with the market portfolio is standardised by the variance of the market portfolio, an asset-specific risk measure β is derived:

$$\beta = \frac{CoV(asset, market)}{var(market)} = \frac{(\sigma_{asset}\sigma_{market})\rho_{asset,market}}{\sigma_{market}^{2}} \tag{1}$$

The expression above suggests that assets riskier than the average are expected to have a β higher than 1, and assets safer than the average will have β lower than 1. The riskless asset, such as cash, will have a β of 0.

For the marginal investor, the cost of equity is as follows:

$$r_e = r_f + \beta(ERP) \tag{2}$$

For an undiversified investor:

$$r_e = r_f + \beta(ERP)\left(\frac{1}{\rho_{sector}}\right) \tag{3}$$

where r_f is a riskless asset for which the investor knows the return with certainty for a given time horizon. Nevertheless, the time horizon must be decided before and should match the length of the project under analysis. *ERP* is the equity risk premium the investors demand for holding a market portfolio. ρ_{sector} is the correlation between the sector and the market. β is a relative risk measure arising from firm-specific risks (including business nature, competition, financial leverage and leverage, and macroeconomic factors).

Over the decades, many models were developed to calculate the risk-based expected return from an investment, most of which were formulated based on the price of an asset and the market. Based on the assumption that the variance of the actual return represents the relative risk measure and the risk should be measured from the marginal investor point of view, the capital asset pricing model (CAPM) provides an easy-to-follow and generalisable procedure to estimate expected return that can be used as a cost of equity or hurdle rate. Apart from CAPM, one can also adopt the arbitrage pricing model, the multi-factor, proxy, and accounting models. Although the arbitrage pricing model, the multi-factor model or even the proxy models tend to do a better job of representing the sector and market risk, they are very comprehensive and hard to generalise as they have heavily relied on the statistical analysis performed using historical data, which might not represent the future (Damodaran, 2014).

The present study employs a similar strategy to the accounting model, which measures the risk based on the volatility in earnings (cash flows). The introduced model assumes that the value of offshore wind projects is more related to cash flow stability rather than growth speculation. Thus, one can argue that the mean value and variance of cash flow distribution can be used to calculate the project's intrinsic value, representing market pricing in an efficient market environment.

The introduced model does not require market pricing, thereby opening up an opportunity to extend the calculation for the projects executed by private companies. The risk measure solely focuses on the cash flow stability, and the model needs to be complemented by considering the effect of financial structure (debt-to-equity ratio, cash position) to derive levered β. By doing so, β becomes a measure comparable to the market.

The introduced model does not have the drawback of some of the commonly used accounting models, which is that accounting numbers might not be revealed as frequently as the market pricing. In contrast, digitalisation and continuous data collection make up-to-date cash flow estimation possible. Furthermore, because the model measures the risk involved relative to the market, it allows for validation based on the statistical data calculated based on CAPM on the sector in which the project takes part.

2.3.1. Regression-based relative risk measure

The regression analysis is one of three ways by which the relative risk measure β can be obtained. The historical data on market prices are used to perform the regression analysis, where the regression slope measures an asset's riskiness. It is worth noting that the R-square of the regression stands for the proportion of the variance of a firm that can be attributed to market risk; then, the rest can be attributed to firm-specific risk. In other words, it is the correlation between the asset and the market. The regression-based β is arguably the most common approach and can be considered appropriate for companies that have been publicly traded for a long time. Nonetheless, it is less so for private companies or new projects.

A peril mentioned several times here is that, more often than not, historical data might represent neither the current macro and micro-economic conditions nor the conditions in the future. Moreover, there is a trade-off between the number of data points and sampling size that data analysts need to compromise. Overall, it can be argued that this approach provides with a backwards-looking measure for the risk of an asset (Damodaran, 2014).

2.3.2. Bottom-up approach

A more forward-looking approach was suggested by Damodaran (2014), which is named as Bottom-up Approach for relative risk measure. The approach does not require past prices of an individual firm or asset to estimate its β, whereas the approach relies on the median value of the publicly traded companies worldwide in the sector of interest. The large the number of companies included, the more robust the representative risk measure becomes.

The financial leverage premium is removed from levered β ($\beta_{levered}$) to get unlevered β ($\beta_{unlevered}$) as:

$$\beta_{unlevered} = \frac{\beta_{levered}}{1 + (1 - T)\frac{D}{E}} \tag{4}$$

where D is debt, E is equity, and T is the tax rate. Finally, $\beta_{unlevered}$ is adjusted by the cash-to-firm value ratio because cash has no correlation with the market, and its β is 0. $\beta_{project}$ is calculated as:

$$\beta_{project} = \frac{\beta_{unlevered}}{1 - \frac{cash}{Firm\ Value}} \tag{5}$$

Although the bottom-up approach does rely on stock prices directly, to get the median of levered β, it is required to find as many publicly traded companies as possible and calculate the relative risk measure β of these companies based on the historical data using regression analysis. The expression above can be used to obtain a firm's or project's β by reversing the expression to estimate the $\beta_{levered}$.

The bottom-up Approach uses the power of statistics and provides a proxy for the company when the financial leverage and cash position are taken into account. However, the sector's risk relative to the market does not necessarily infer the companies or project risk because the statistical descriptors depend heavily on the subset of companies used in the analysis. The statistical uncertainty caused by insufficient data points and outliers hinders the success of the bottom-up approach.

2.3.3. Certainty equivalent approach

The certainty equivalent is a "certain" amount of return a risk-neutral investor is willing to accept in the same way that the investor would accept a higher expected return from a risky asset. For the sake of consistency, the intrinsic value of an asset must be the same even if one uses the certainty equivalent or expected return because the investor must compare these returns against their corresponding counterpart. In this case, the investor preferring certainty equivalent return must discount the cash flows using a risk-free rate. In contrast, the investor preferring the expected return must discount the cash flows using a hurdle rate (cost of equity). Essentially, there cannot be any difference between the obtained values because the higher cash flows are annulled by a higher discount rate. This equilibrium is expressed as in the following:

$$\sum_{i=1}^{t} \frac{E[CF_i]}{(1 + r_e)^i} = \sum_{i=1}^{t} \frac{CECF_i}{(1 + r_f)^i} \tag{6}$$

where E[CF_i] is the expected annual cash flow at year i, $CECF_i$ is the certainty equivalent cash flow, r_e is the cost of equity, r_f is the risk-free rate, and t is the project duration.

The certainty equivalent approach requires a comprehensive probabilistic analysis of revenues and operating expenses over the course of the project life. The following section presents the details of such an analysis within the scope of offshore wind projects.

3. Risk-based analysis of offshore wind projects

3.1. Methodology for the project-specific risk measure estimation

The methodology introduced for risk modelling of life extension projects of offshore wind farms under considering macroeconomic

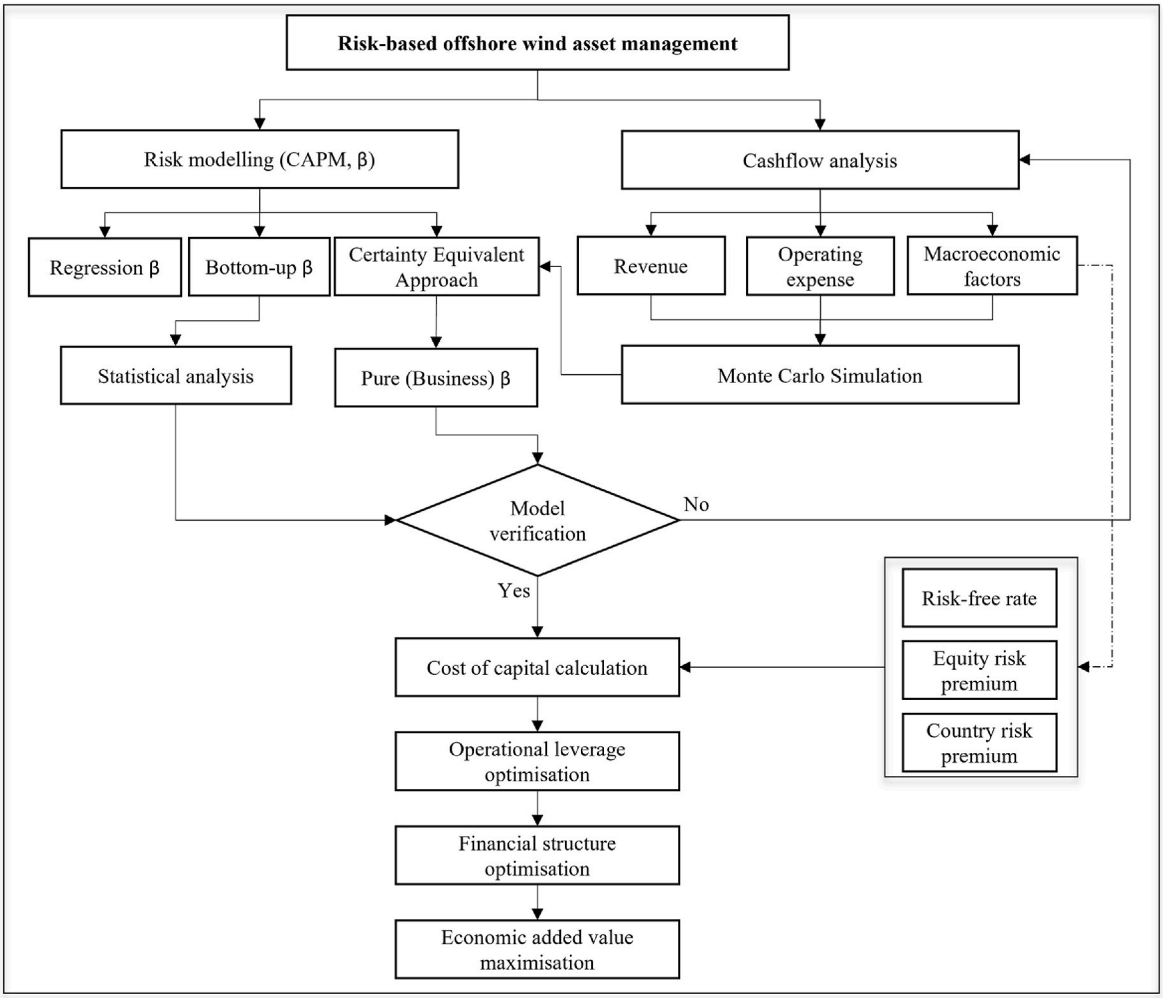


Fig. 1. Risk-based framework to analyse and manage offshore wind projects.

factors is illustrated in Fig. 1. To calculate an interest rate based on operational characteristics, the present study assumes that two net present value equations can be written, yielding the same result: 1) Certain cash flows discounted at a risk-free rate and b) expected cash flows discounted at the cost of capital. The pure project/business-related risk is then estimated by solving the resulting equation for the unknown cost of capital.

The underlying parameters defining the project-specific premium are modelled as stochastic variables, and a probabilistic financial analysis is conducted using Monte Carlo simulation. The independent input variables are the annual energy yield, strength of demand and supply, fixed cost-to-variable cost ratio, inflation, energy prices etc.

The statistical data collected for publicly traded renewable energy companies worldwide validated the model developed to calculate the cost of capital. Afterwards, particular attention is given to optimising the project's financial structure that minimises the cost of capital. The developed model is demonstrated for a fictitious ageing offshore wind farm under different economic circumstances.

3.2. *Probabilistic cash flow analysis*

3.2.1. *Revenue estimation*

The revenue produced by an offshore wind farm depends essentially on two changing variables, energy production and electricity price. The net annual energy production can be defined as a function of wind condition (mean wind speed and turbulence intensity), control system efficiency, wake effect, electrical losses, lack of reliability of components leading to downtime, and, last but not least, curtailment. To put it in simple terms, the factors mentioned above can be encapsulated in parameters, namely capacity factor, availability and curtailment, and annual energy production can be written as:

$$AEP = WH \times RP \times CF \times AV \times CR \tag{7}$$

where *AEP* is related to the annual energy production, *RP* is related to the rated power of the wind turbine, *CF* is related to the capacity factor, *AV* is related to the availability, and *CR* is currency. These variables are stochastic in nature and can be described in probabilistic terms.

The degree to which these variables account for the variance of overall annual energy production also depends on the number of offshore wind turbines in an offshore wind farm. It might be argued that as the number of OWTs gets larger, the uncertainty associated with the wake effect, cable loss, wind profile, availability, and curtailment increases. On the flip side, as offshore wind farm gets bigger, the law of large number works in favour of the variance of overall offshore wind farm energy production because fluctuations occurring for each OWT are cancelled even if they are somehow correlated (see Fig. 2).

The wake effect and variability of wind profile explain the variation in power production between OWTs, which requires detailed modelling. The fidelity of the modelling affects the uncertainty associated with these parameters. Such detailed probabilistic analyses are not within the scope of the present work; thus, reasonable assumptions are taken to account for these parameters affecting the overall annual energy

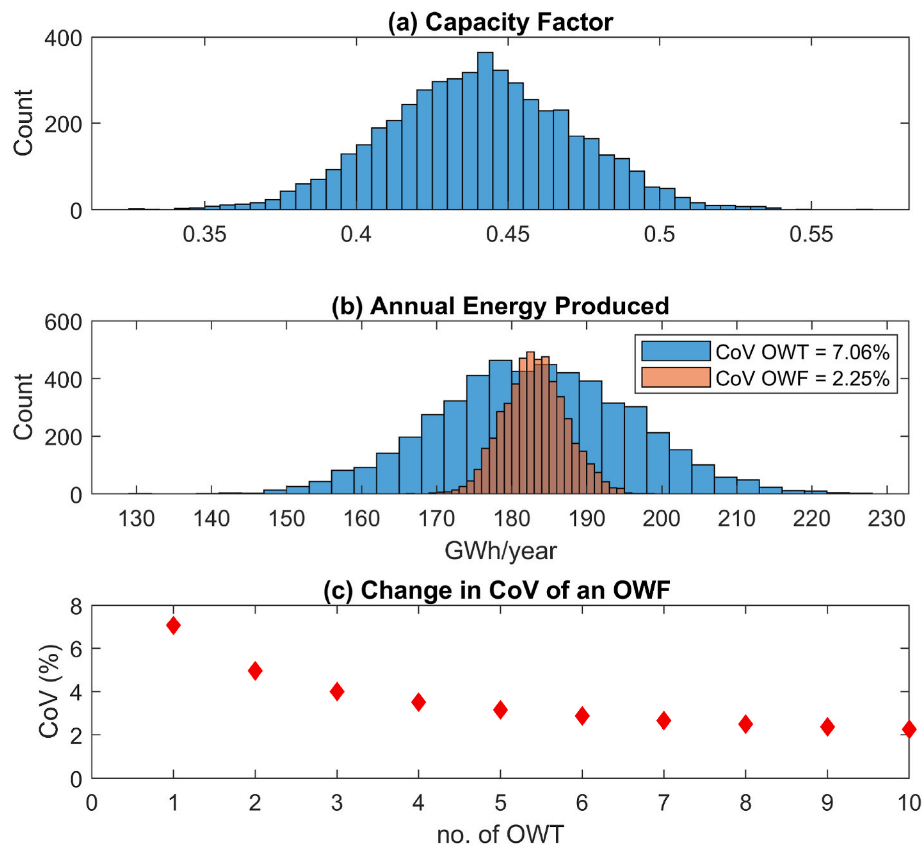
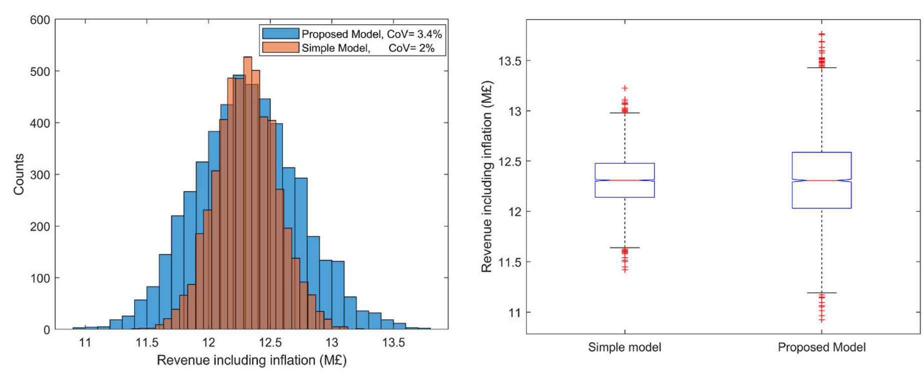


Fig. 2. Factors influencing the revenue stream and their variations **(a)** Distribution of capacity factor **(b)** Annual energy produced for an offshore wind turbine (OWT) **(c)** for an offshore wind farm (OWF).



(a) (b)

Fig. 3. Comparison between the evaluated revenue models **(a)** Histogram **(b)** Boxplot.

production.

The price of electricity is the other main variable regarding the expected revenue of offshore wind farms. The price is usually defined by the power market based on the supply-demand equilibrium. The market price is exposed to significant uncertainty, which is governed by seasonal household demand, industrial demand, weather conditions, alternative source prices, and macroeconomic factors. In many countries, the corresponding risk has been mitigated by power purchase agreements to warm investors and developers, boosting the development in the offshore wind industry experienced in the last decade.

However, there is still a political and regulatory risk associated with these contracts. The present study focuses on adjusting the strike price based on expected inflation. Nevertheless, it acknowledges the fact that the contract details and even tax and lease benefits matter in the final account. In light of these considerations, the annual revenue obtained can be written as follows:

$$Rev = (AEP \times FiT)\cdot\left(1 + r_{Inf,demand}\right)^{t} \tag{8}$$

where FiT and $r_{inf,\ demand}$ are the feed-in-tariff and inflation rate on the demand side, respectively.

One way to deal with the effect of inflation on revenue is to apply a deterministic inflation rate to the revenue. The present study proposes, instead, that inflation can be described probabilistically and applied to the revenue annually in a simulation. By doing so, the stochastic nature of the macroeconomy can be reflected in the revenue stream throughout service life accumulatively, which is a more realistic project valuation. Such an effect is illustrated in Fig. 3, where the proposed model exhibits a larger variance than the simple model that only accounts for the

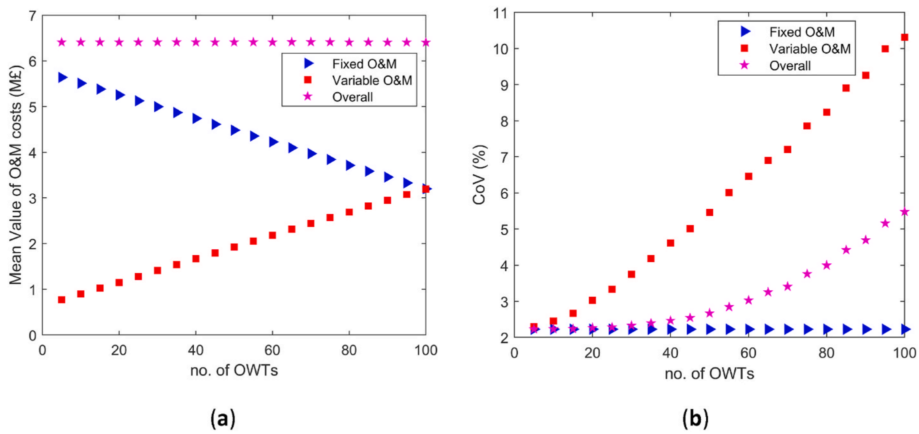


Fig. 4. Operating expense components (fixed O&M, variable O&M, and overall OPEX (a) Mean value (b) Coefficient of variation.

variance in revenue.

3.2.2. *Operating expense estimation*

The offshore wind farms are infrastructure projects needing high upfront investment (CAPEX). Nevertheless, OPEX is still an essential factor and gaining even more importance considering variable O&M costs due to unscheduled maintenance and repair of ageing support structures. The contribution of variable O&M costs is expected to be much more prominent when there are more ageing OWTs to maintain, which might cause bottlenecks due to the lack of skilled O&M labour. Such consideration is essential for future offshore wind farms designed to operate in harsher marine and narrower weather windows for remedial actions.

OPEX can be categorised as operation (O) and maintenance (M), where the operation cost covers administration, health and safety inspections, lease, insurance, and transmission charges, and the maintenance cost covers corrective, preventive and unscheduled maintenance, port, vessel and labour (Bosch et al., 2019). OPEX can also be categorised as fixed and variable O&M, which is much more relevant from a financial risk point of view as it describes the degree of operating leverage.

Operating leverage measures how an operation can translate the change in revenue into the difference in income, which can also be represented as a fixed cost-to-total cost ratio. High operating leverage means much higher revenues during good times and much lower revenues during bad times; thus, it increases the volatility and riskiness of the investment.

$$Exp = [OPEX \times AEP \times (1 - rMar) + OPEX \times AEP \times rMar] \times CR \times \left(1 + r_{Inf,supply}\right)^t \quad (9)$$

where Exp is an overall operating expense, *OPEX* stands for the characteristic OPEX value including both fixed and variable O&M. *rMar* is fix-to-variable O&M. $r_{inf,\ supply}$ is the inflation reflecting the supplier side, which can differ from the rate that is agreed by the demand side (power purchaser and government support scheme). Like in the revenue calculation, the uncertainty associated with the inflation o the supplier side should also be reflected throughout the service life.

As stated before, the fixed O&M can dominate the operational cost structure at the start of the service life. Towards the end of the service life, the variable O&M can impact the total O&M costs more due to unscheduled remedial actions. However, the operators can also intentionally reduce the operating leverage for a smoother cash flow stream. Such efficiency optimisation might also influence the useful life of offshore wind assets.

Another factor that can play a role in terms of operating leverage is the number of ageing OWTs. Based on the economies of scale principle, the contribution of variable O&M is expected to increase for a larger offshore wind farm. The impact of offshore wind farm size is illustrated in Fig. 4. It is also worth mentioning that the model developed here can also be improved by considering the learning curve associated with O&M cost reduction due to gained experience when such data is available.

Some initial investments can be considered part of the fixed O&M that can pay off significantly to achieve lower unscheduled maintenance costs, in turn, variable O&M costs. These are structural health monitoring systems supported by embedded sensor systems, Supervisory Control and Data Acquisition, digital twins of components, and drones. The data acquired can be trained by machine learning algorithms supported by physics-based models to devise optimal inspection and maintenance strategies avoiding costly unscheduled interventions (high day-rate of vessel and labour).

Table 2
Stochastic variables for cash flow analysis.

Variables	Risk factor	Mean value	CoV (%)	Reference
Mean wind speed	Technology	8.5	3	Mora et al. (2019)
Capacity factor	Technology	0.44	3	(Wilkie and Galasso, 2020, 2022)
Availability-Downtime	Technology-Legal	0.95	1	(Burke and Malley, 2011; Staffell and Green, 2014)
Feed-in-tariff (strike price)	Political-Economic	50 £/MWh	1	(Haji Bashi et al., 2016; Ioannou et al., 2018, 2020)
Fixed operational costs	Technology-Environmental	28 £/MWh	1	(Heck et al., 2016; Ioannou et al., 2020; Kerres et al., 2015; Rinaldi et al., 2021)
Variable operational costs	Technology-Legal-Environmental	7 £/MWh	2	(Heck et al., 2016; Ioannou et al., 2020; Kerres et al., 2015; Rinaldi et al., 2021)
Inflation-demand	Political-Economic	2%	3	(Ioannou et al., 2018, 2020)
Inflation-supply	Political-Economic	2%	5	(Ioannou et al., 2018, 2020)
Currency	Political-Economic	1	2	

3.3. *Monte Carlo Simulation*

The probabilistic discounted cash flow analysis is carried out using Monte Carlo simulation. The simulation is for an offshore wind farm with 50 OWTs for an extended service life of 10 years. The random

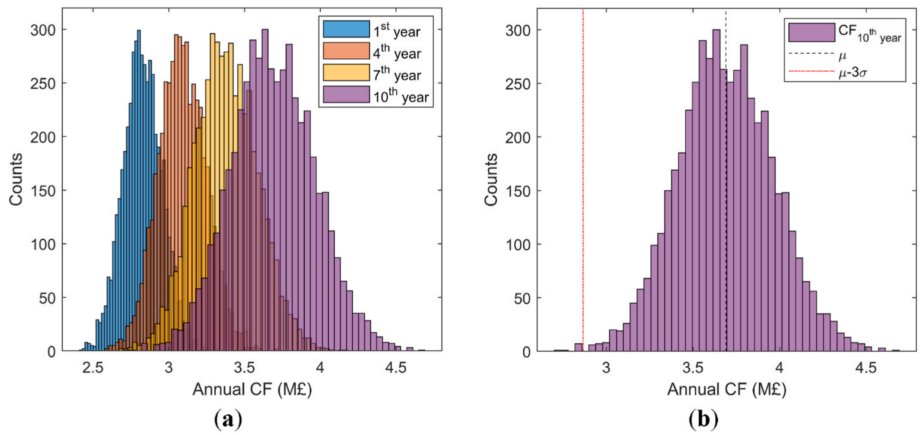


Fig. 5. Estimated annual cash flow in different years **(a)** Histogram **(b)** Expected cash flow vs Certainty equivalent cash flow.

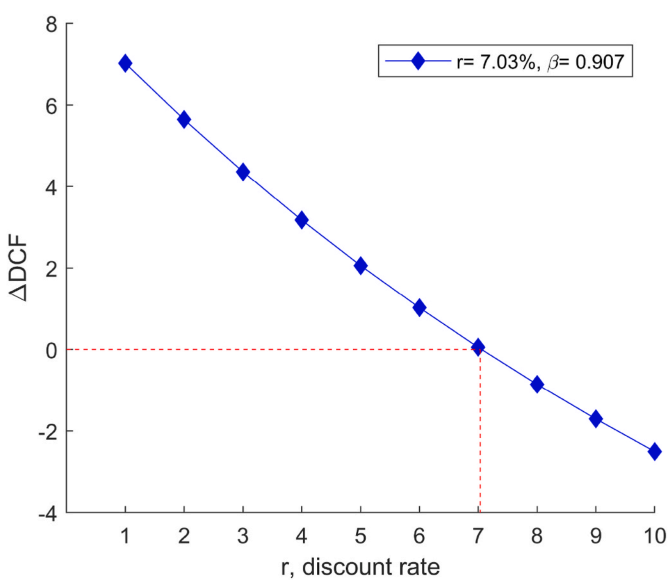


Fig. 6. Estimating $\beta_{project}$ value that minimises ΔDCF.

variables used in the Monte Carlo simulation are presented in Table 2.

The statistical descriptors of the cash flow at each year are calculated to determine the expected cash flow (50% probability of exceedance) and the certainty equivalent cash flow (99.7% probability of exceedance). Fig. 5 shows that the variance of the annual cash flow increases substantially with time. Consequently, the discounted cash flows (DCF) analysis may differ significantly from the DCF analysis performed deterministically.

3.4. Certainty equivalent cash flow approach for beta estimation

The probabilistic analysis of revenue and operating expenditure results in certainty equivalent cash flows to be discounted at a risk-free rate, whilst the expected cash flows are to be discounted at the cost of equity. The present study estimates the relative risk measure by finding the discount rate that minimises the discounted cash flow difference (ΔDCF) between the DCF calculated using expected cash flows and the DCF calculated using the certainty equivalent cash flows.

$$f(r) = \sum_{i=1}^{t} \frac{CF_i}{(1+r)^i} - \sum_{i=1}^{t} \frac{CECF_i}{\left(1+r_f\right)^i} \tag{10}$$

$$r = \underset{r}{argmin} f(r) \tag{11}$$

$$\beta_{business} = \left(r - r_f\right) / ERP \tag{12}$$

$$\beta_{unlevered} = \beta_{project}\left(1 - \frac{cash}{FV}\right) \tag{13}$$

$$\beta_{levered} = \beta_{unlevered}\left(1 + (1-T)\frac{D}{E}\right) \tag{14}$$

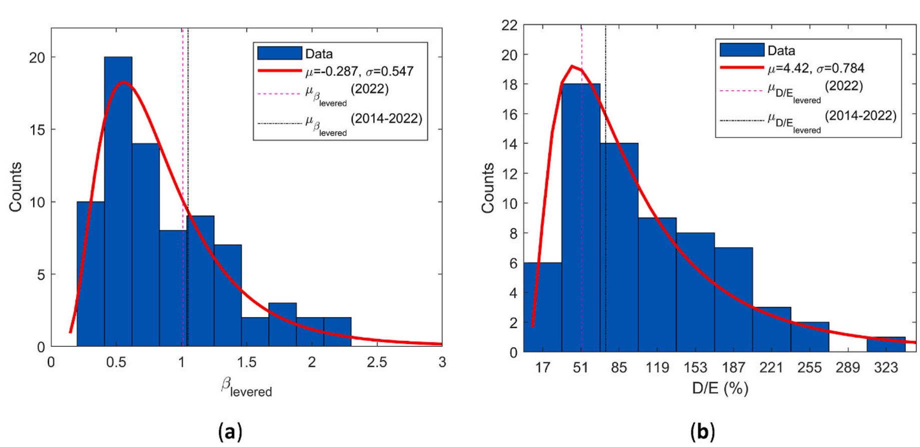


Fig. 7. Statistical analysis on project riskiness and financial leverage for publicly traded renewable energy companies **(a)** project riskiness ($\beta_{levered}$) **(b)** Leverage (D/E).

By solving Eq. (11), the relative risk measure β related to the only project (see Fig. 6). Afterwards, $\beta_{project}$ can be translated into levered $\beta_{levered}$ using Eqs. (6) and (7), which could be used to calculate the cost of equity accounting for cash position and financial leverage.

There are two approaches that can be used in the offshore industry to adjust the relative risk measure of project $\beta_{project}$ for cash position and financial leverage. The first is corporate finance, and the latter is project finance. In corporate finance, the firm raises debt and equity; hence, investors use the cash position and debt-to-equity ratio of the firm undertaking the project, which is commonly seen in projects from mature and well-established industries such as Oil & Gas.

In the project finance approach, the debt and equity are raised within the scope of a special-purpose vehicle. In this case, only cash flows from the projects are paid first to debt and then to equity owners. Furthermore, the debt owner cannot claim any assets from the firm in case of the project cannot fulfil its obligation to pay its debt (both interest and principal) (Steffen, 2020).

Such an approach is more appropriate for new industries, such as offshore wind, to increase investors' risk appetite, especially institutional investors. In this regard, PWC (2020) reported that the overwhelming majority of offshore wind projects in Europe had been financed by the project finance approach. This partially caused the consistent decrease in the risk premium attached to offshore wind projects, as claimed by Steffen (2020).

Before calculating the project cost of capital with optimal financial leverage, the cost of equity estimated in the present study is compared to the statistical analysis performed considering publicly traded companies worldwide in the offshore wind industry. The relative risk measure $\beta_{levered}$ of these companies is calculated using a regression-based approach considering five-year stock prices compared with the S&P 500 market index. The comparison shown in Fig. 7 confirms that the relative risk measure calculated in the present study lies the reasonable levels. For further support of the estimated cost of capital here, IRENA (2022) reported the cost of capital to be 7%, considering a net of 2% inflation for countries within the Organization for Economic Co-operation and Development.

3.5. Cost of capital and optimal financial structure for maximum value

The previous sections introduce a methodology to calculate the relative risk measure associated with an offshore wind farm and systematically explain the steps to calculate it based on the data related to the operation of wind turbines, operating leverage, and macroeconomic factors.

The present section brings together other constituents of, first, the cost of equity and then the cost of capital, i.e., hurdle rate. To estimate the cost of equity, it is required to define three main parameters: risk-free rate, equity risk premium and the relative risk measure. Afterwards, the weighted cost of debt needs to be added to the weighted cost of equity to calculate the cost of capital, which can be formulated as in the following (Damodaran, 2014):

$$r_c = \frac{E}{D+E}(r_e) + (1-T)\frac{D}{D+E}(r_d) \tag{15}$$

$$r_e = r_f + \beta_{levered}(ERP)(rMar) + \beta_{levered}(ERP)\left(\frac{1}{\rho_{sector}}\right)(1-rMar) \tag{16}$$

$$ERP = ERP_{mature} + CRP\frac{\sigma_{equity}}{\sigma_{bond}} \tag{17}$$

$$r_f = T - Tbond_{10\ year} - CRP \tag{18}$$

$$r_d = r_f + spread \tag{19}$$

where r_c, r_e, and r_d are the cost of capital, cost of equity and cost of debt, respectively. $\beta_{levered}$ is the relative risk measure after adding to the contribution of cash position and debt-to-equity ratio. ERP_{mature} is the equity risk premium associated with a mature stock market, most commonly the United States stock market. CRP is the country risk premium arising from the default risk of a sovereign country failing to pay its debt. σ_{equity} and σ_{bond} is the standard deviation associated with the equity and bond markets of the country of interest. $rMar$ is the proportion of marginal investors in terms of total investors in the project.

Table 3
Default risk spread for riskier firms (Damodaran, 2014).

EBIT Interest coverage rate	Rating in S&P	Default spread (%)
10^5–12.5	AAA	0.63
12.5–9.5	AA	0.85
9.5–7.5	A+	1.07
7.5–6	A	1.18
6.0–4.5	A-	1.33
4.5–4.0	BBB	1.71
4.0–3.5	BB+	2.31
3.5–3.0	BB	2.77
3.0–2.5	B+	4.05
2.5–2.0	B	4.86
2.0–1.5	B-	5.94
1.5–1.25	CCC	9.46
1.25–0.8	CC	9.97
0.8–0.5	C	13.09
0.5–-10^5	D	17.44

$Tbond_{10\ year}$ is a 10-year treasury yield for the country of interest because the project is considered to be for 10 years in the present study. Thereby, the cost of capital calculation does not need to be concerned with reinvestment rates. For a more precise calculation, a risk-free rate that varies from year to year can pay off in the net present value calculation when this change is expected to be dramatic.

Under the conditions of unstable inflation, net present value calculation can be done in real terms since the risk-free rate is just the real interest rate (~0.50%) and expected inflation rate. Thus, the effect of inflation on cash flows, as well as the hurdle rate, is removed. This is rather useful, especially when investors are certain that inflation on the demand and supply sides is almost identical. However, in the case of inflation, the demand and supply sides differ; it is more appropriate to account for both ends of the valuation.

Like the varying nature of inflation and the risk-free rate, the equity risk premium changes because it merely reflects investors' risk appetite. Assuming a positive correlation between economic prosperity and risk appetite is reasonable, and this means that during tough economic conditions, investors become more risk-averse and ask for a higher risk premium. This issue is left to be investigated in future work.

The currency in which cash flows are calculated also dictates the risk-free rate choice. For a project or firm expected to receive its revenue in different currencies, the cost of capital calculation needs to be done separately and take a weighted average of these cost of capital estimates depending on the revenue portion in each currency. This affects assumptions made for both risk-free rates and equity risk premiums.

The United States equity risk premium (ERP) is taken as 5.20%, whilst the volatility ratio between equity and country bond market is taken as 1.15 (Damodaran, 2022b). The equity risk premium can be attained in three ways: survey, historical records, and the implied equity premium. The implied equity premium is calculated based on the returns of the market index, and it reflects the present risk premium in the equity market rather than what was in the past, which can be misleading for developing countries. For the United Kingdom, CRP is taken as 0.51%, and the 10-year Treasury yield is taken as 2.5% (Damodaran, 2022a).

The cost of debt is equal to the sum of the risk-free rate and default spread associated with the firm. It is a common practice to evaluate a company's default risk based on proxies such as interest coverage, debt-to-capital ratio, income-to-sales, and return on capital. The present study uses earnings before interest and taxes (EBIT) to annual income

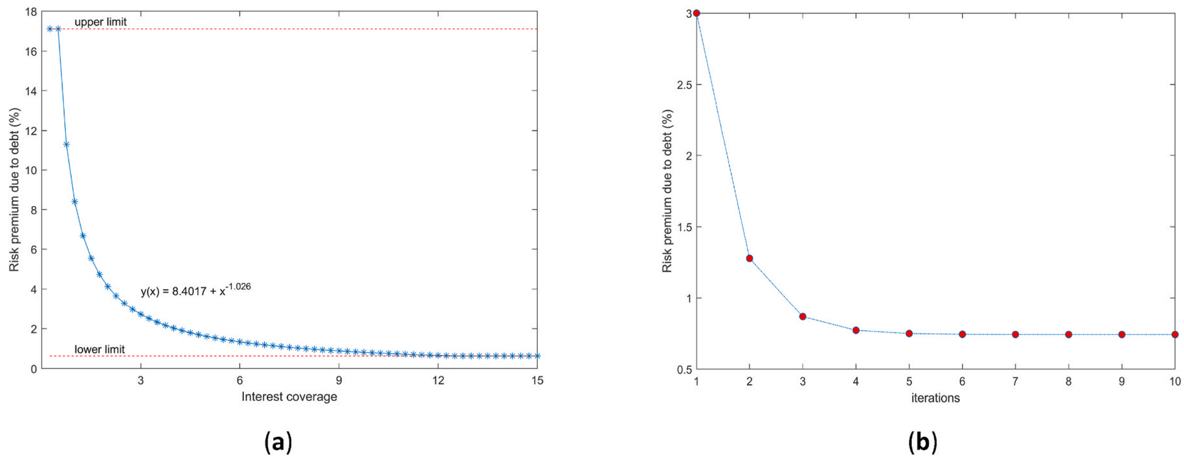


Fig. 8. Cost of debt calculation **(a)** spread as a function of *ICR* **(b)** iterations.

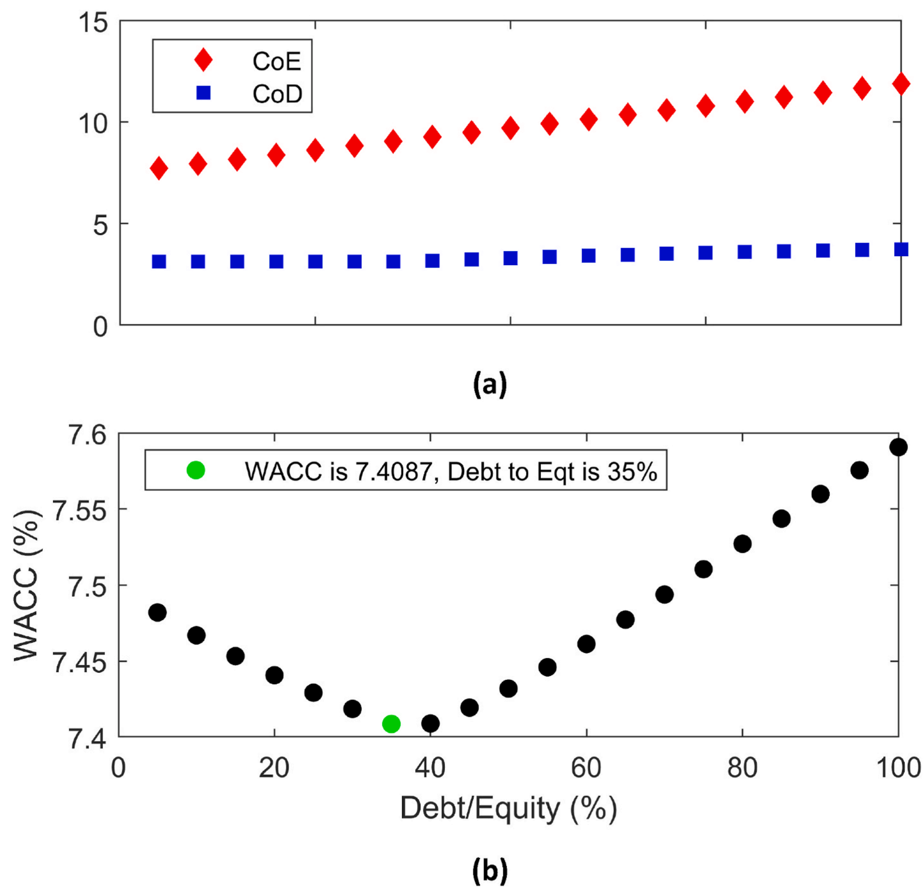


Fig. 9. Financial structure optimisation. **(a)** Cost of debt (CoD) vs cost of equity (CoE) **(b)** Weighted average cost of capital (WACC).

expense on existing debt. The EBIT interest coverage ratio and its corresponding rating default spread are presented in Table 3, which are given for relatively riskier companies.

It is worth noting that lower default spread values are to be expected for large-cap companies with a diversified portfolio of businesses. It should also be noted that the estimation of debt cost requires loop calculation as default spread (*spread*) affects the cost of debt, which then affects the interest coverage ratio (*ICR*). This can be dealt with using the Newtown-Rapson iterative approach (see Fig. 8). To facilitate this process, default spread is formulated through a quadratic regression fit as:

$$spread = \begin{cases} 0.69, ICR < 0.5 \\ 8.4017\left(ICR^{-1.026}\right), 0.5 \leq ICR \leq 12.5 \\ 17.44, 12.5 < ICR \end{cases} \tag{20}$$

$$ICR = \frac{EBIT}{r_d D} \tag{21}$$

$$EBIT = \frac{ROCE}{D + E} \tag{22}$$

Table 4
Variables used to generate prosperous and crises scenarios.

Variables	Prosperous	Crises
r_f (%)	2.5	7.5
ERP (%)	5	9
CRP (%)	0	1.5
CoV in $r_{inf,\ demand}$ (%)	1	3
CoV in $r_{inf,\ supply}$ (%)	1	5
CoV in *CR* (%)	1	2
T (%)	10	20
rMAR	1	0.75

$$ROCE = \frac{\frac{\sum_{i=1}^{t} CF_i}{t}}{\sum_{i=1}^{t} \frac{CF_i}{(1+r)^i} + \left(\frac{\frac{(1+g)}{(r-g)}CF_t}{(1+r_e)^t}\right)} \tag{23}$$

The cost of capital can be calculated for an already existing debt-to-equity ratio; however, the debt-to-equity ratio can be taken to a level that can minimise the cost of capital. This process is called financial structure optimisation. The firms involving a high debt-to-equity ratio have a higher chance of default, which is reflected in the relative risk measure and firm-specific spread on the cost of debt. However, the cost of equity is generally higher than the cost of debt. A minimal capital cost can be achieved by finding the right amount of debt-to-equity. The financial structure optimisation minimises the cost of capital associated with the firm or project; thereby, the economic value added by the project is maximised. The results of the financial structure optimisation are shown in Fig. 9.

4. Effect of macroeconomic factors on the riskiness of offshore wind projects

The previous sections defined the types of risks to which an offshore wind project is subjected and presented an operational-data-driven risk assessment framework. It is argued that the higher the difference between the expected return on capital and the cost of capital, the greater the economic value added by the offshore wind project. It can also be argued that this difference can significantly shrink and even get negative during tough economic conditions.

In the present section, the effect of macroeconomic factors on the riskiness of offshore wind projects considered for life extension is investigated by analysing two distinct scenarios. These scenarios are considered for a fictitious offshore wind project developed in countries with a mature market. Although the values used to generate these scenarios are speculative, the values can be deemed reasonable considering the mature market conditions in the last decade. It is also worth mentioning that the developed risk model relies heavily on the success of descriptive statistics regarding the operational and macroeconomic data, and the resulting weighted average cost of capital is sensitive to the changes in the stochastic variables. Nevertheless, the main goal of the section is to demonstrate how dramatically the project risk can change from prosperous times to economic crises, making offshore wind projects economically unattractive.

The first scenario is related to prosperous economic conditions, and the latter is during crises, especially driven by higher-than-usual inflation. The scenarios are characterised by the variables presented in Table 4, and the cost of capital associated with these scenarios is shown in Fig. 10.

During prosperous times, the expected inflation is aligned with a gross domestic product of a developed country, which can be assumed as 2%. Consequently, a risk-free rate can be assumed as 2.5%. In good times, the investors tend to seek a lower equity risk premium, and the country risk premium is expected to be close to zero. The prosperous times also imply a significant contribution of the marginal (well-diversified) investor, relatively lower corporate tax and less volatility in currency, and inflation (both demand and supply sides).

During worsening economic conditions or crises, if it is driven by

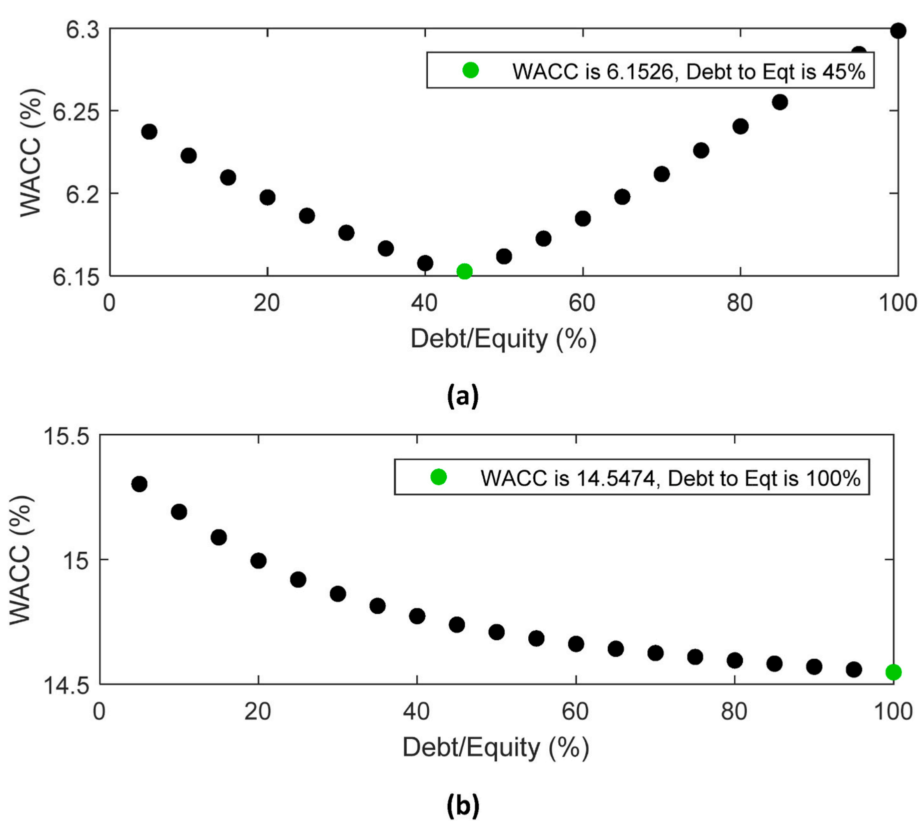


Fig. 10. Cost of capital for a medium-sized offshore wind project (a) prosperous times (b) crises.

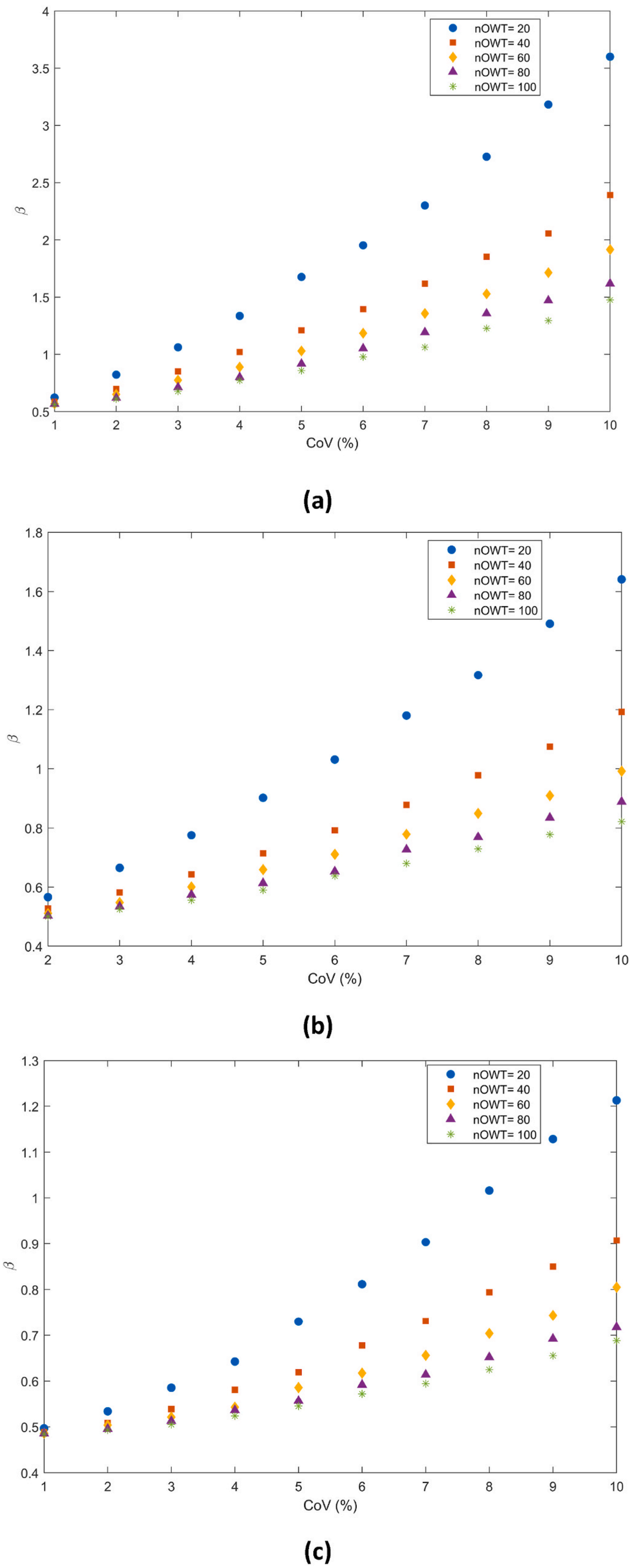


Fig. 11. Effect of offshore wind farm size on project riskiness, extended service life (a) 5 years (b) 10 years (c) 15 years.

supply-demand disequilibrium and inflation, one should expect much higher volatility in currency and inflation on both sides and some discrepancy between expected inflation rates as well. Correspondingly, a higher risk-free rate, equity risk premium, and country risk premium should be expected. This eventually may result in worsening participation of the marginal investor in projects with a lower rate of return in the face of a potential recession, which can then induce the participation of public entities to introduce higher taxation to fund or refinance these projects.

Economic crises punish those who take projects low in added value, meaning a high capital cost and a low return rate on capital. Nevertheless, there is still to be done to lower the cost of capital apart from finding the optimal financial structure and keeping marginal investors invested in life extension projects. The other fundamental determinants of relative risk measure are the nature of the business, operating leverage, cash position, diversified project portfolio in different currencies, supply chain reliability, and competitive advantage for demand power.

Amongst all the aforementioned factors, the business/operation type is especially critical. Provided that the offshore wind project is well supported by the government, eliminating contract-related uncertainties such as energy price, currency, curtailment, inflation, and tax rate, which make the product non-discretionary with pricing power.

The way to de-risk offshore wind life extension projects can be investigated by looking at the number of offshore wind turbines and the duration of life extension. The number of offshore wind turbines that fit for life extension can vary depending on the condition of the wind turbine and support structure. Through maintenance and repair, repowering, repurposing, or lowering the operational intensity of a functional offshore wind turbine, the number of OWTs fit for life extension can be increased.

Another way to de-risk the project is to increase the duration of life extension as long as the cash flow stability is ensured. In this regard, the operating leverage (fixed O&M to total cost ratio) is critical and needs to be optimised. The intelligent asset management system supported by structural health monitoring can decide on the operational intensity of wind turbines that will allow for opportunistic maintenance and fixed cost reduction, thus creating a more stable cash flow stream.

Fig. 11 shows that by increasing the duration of a project and involving as offshore wind turbines as possible, the relative risk measure associated with the life extension of an ageing offshore wind farm can be reduced significantly, even under very uncertain macroeconomic environments (high coefficient of variation (CoV) in expected inflation).

5. Conclusions

The present study investigated the underlying parameters causing project-specific relative risk measures based on operational and macroeconomic data and how these parameters influence offshore project valuation. To this end, a new methodology was introduced by incorporating the probabilistic financial appraisal with the certainty equivalent approach to derive the relative risk measure. The relative risk measure was first defined as project-specific, then adjusted by financial leverage and the diversity of assets such as cash.

The study assessed the effect of the macroeconomic factors influencing the cost of capital under two distinct scenarios where these factors affect not only market-related parameters but also offshore wind project-related parameters. Furthermore, the study analysed the degree to which the decision on the life extension of offshore wind farms can be affected by the offshore wind farm size, life extension duration and the uncertainty around the cash flow stream.

In light of the analyses presented above, the present study concludes that.

1. Every country, every sector, every firm, and every project has its own unique exposure to risk. Applying a broad-scale but erroneous hurdle

rate (cost of capital) to projects with different exposure to risk results in overinvesting in high-risk projects and under-investing in low-risk projects, making the firm risker, which can be translated into risk in the sector over the long run.

2. The historical records used for the relative risk measure are not the best predictor of future prediction regarding the riskiness of a project or business as the business, socio-politic and economic environment can evolve over time. This argument is also valid for the parametric equations used for OPEX per energy produced as they come from a different set of offshore wind turbines, different cost structure structures and different countries. The modelling uncertainty and uncertainty propagation (time-dependent) element of such cost components in a financial model must be acknowledged and included in the analysis.
3. The probabilistic method proves to be very useful for the financial appraisal (discounted cash flow) as it accounts for the uncertainties associated with an OWF with a very long project life. The underlying processes causing these uncertainties (aleatory and epistemic) must be analysed carefully.
4. The economic conjuncture can also evolve over time; thus, decision-makers cannot afford to overlook the economic cycles (from prosperity to crises and recessions) and investors' sentiment governed by loss aversion and unfamiliarity bias for emerging industries.

As for future work, the stochastic optimisation of operating leverage using operational and economic data seems to be a promising future work. The time-domain simulations for revenue, operating cost and the cost of capital are recommended instead of using static values. The resulting dynamic approach allows for more realistic and effective risk offshore wind asset management.

Because the LCoE is a technology-specific comparison metric, the positive derivative of economic added value can be suggested as a key performance metric. The results of this study can be used to engineer possible ways to maximise economic value added by sizeable offshore wind projects.

CRediT authorship contribution statement

Baran Yeter: Conceptualization, Methodology, Coding, Formal analysis, Investigation, Writing – original draft. **Yordan Garbatov:** Conceptualization, Methodology, Investigation, Writing – original draft, Supervision. **Feargal Brennan:** Conceptualization, Methodology, Investigation, Writing – review & editing, Supervision. **Athanasios Kolios:** Conceptualization, Methodology, Investigation, Writing – review & editing, Supervision.

Declaration of competing interest

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

Data availability

Data will be made available on request.

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Appendix a

Table A.1
List of renewable energy companies considered in the validation and their levered relative risk

NAME	$\beta_{levered}$ (11/2017–11/2022)
ORSTED A/S	0.57
IBERDROLA S.A.	0.52
VESTAS WIND SYSTEMS A/S	1.02
SIEMENS ENERGY AG	0.91
BROOKFIELD RENEWABLE PARTNERS L.P.	0.75
EDP - ENERGIAS DE PORTUGAL, S.A.	0.51
EQUINOR ASA	0.71
AKER SOLUTIONS ASA	2.29
RWE AG	0.73
NORDEX SE	2.19
AVANGRID INC.	0.36
XINJIANG GOLDWIND SCIENCE & TECHNOLOGY CO., LTD.	1.35
GENERAL ELECTRIC COMPANY	1.12
NEXTERA ENERGY PARTNER LP	0.86
ZHEJIANG WINDEY CO., LTD.	0.74
SHANGHAI ELECTRIC GROUP	0.51
DOOSAN ENERBILITY CO., LTD	2.08
NORTHLAND POWER INC.	0.45
TRANSALTA RENEWABLES INC.	0.63
BORALEX INC.	0.50
EDP - ENERGIAS DO BRASIL S.A	0.37
EDF - ELECTRICITÉ DE FRANCE S.A.	1.08
HUANENG POWER INTERNATIONAL, INC.	0.58
ENEL CHILE S.A.	0.68
HUADIAN POWER INTERNATIONAL	0.43
SSE PLC	0.53
ENGIE SA	1.14
ACCIONA	0.78
CHINA SUNTIEN GREEN ENERGY CORPORATION LIMITED	1.16
CHINA LONGYUAN POWER GROUP CORPORATION LIMITED (CLASS H)	0.86
INNERGEX RENEWABLE ENERGY, INC.	0.34
DUKE ENERGY CORPORATION	0.34
ALLIANT ENERGY CORPORATION	0.46

(continued on next page)

Table A.1 (*continued*)

NAME	$\beta_{levered}$ (11/2017–11/2022)
TORAY INDUSTRIES, INC.	0.90
PRYSMIAN SPA	1.34
HEXCEL CORPORATION	1.26
ABB LTD	1.09
ENDESA, S.A.	0.54
AB SKF (CLASS B)	1.25
CS WIND CORP.	2.00
ENEL SPA	0.84
TERNA ENERGY SA	0.53
ARCOSA, INC.	0.55
CLEARWAY ENERGY, INC. (CLASS C)	0.75
BKW AG	0.25
RENEW ENERGY GLOBAL PLC (CLASS A)	0.34
NEOEN SA	0.79
ENERGIEKONTOR AG	1.07
PNE AG	0.70
CONCORD NEW ENERGY GROUP LTD	0.42
CHINA DATANG CORP RENEWABLE POWER CO., LTD. (CLASS H)	0.84
GURIT HOLDING AG	1.11
EOLUS VIND AB (CLASS B)	1.76
INFRASTRUCTURE AND ENERGY ALTERNATIVES, INC. IEA	1.82
CHINA HIGH-SPEED TRANSMISSION EQUIPMENT GROUP CO., LTD.	0.54
UNISON CO., LTD.	1.16
SGL CARBON SE	1.75
DONGKUK STRUCTURES & CONSTRUCTION CO., LTD.	1.39
AMERICAN SUPERCONDUCTOR CORPORATION	1.36
CECEP WIND POWER CORP-A	0.50
MING YANG SMAR-A	0.20
INNERGEX RENEWABLE ENERGY	0.34
TITAN WIND-A	0.63
JINLEI TECHNOL-A	0.37
RIYUE HEAVY IN-A	0.67
TERNA ENERGY SA	0.53
OX2 AB	1.47
CHINA HIGH-SPEED	0.36
SUZLON	1.43
BERKSHIRE HATHAWAY	0.91
TPI COMPOSITES INC	1.64

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