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Multi-parameter analysis and mapping of the levelised cost of energy from floating offshore wind in the Mediterranean Sea

A. Martinez [a], G. Iglesias [a,b,*]

[a] School of Engineering and Architecture & MaREI, Environmental Research Institute, University College Cork, College Road, Cork, Ireland

[b] University of Plymouth, School of Engineering, Computing & Mathematics, Marine Building, Drake Circus, Plymouth PL4 8AA, United Kingdom

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ABSTRACT

Floating offshore wind, far less constrained by water depths than bottom-fixed, has great potential in the Mediterranean Basin. The levelised cost of energy (LCOE) is arguably the single most reliable metric to measure the viability of energy projects. In this work, the levelised cost of energy for floating offshore wind is mapped for the first time in the European and Eastern Mediterranean with a detailed cost breakdown and a focus on semi-submersible platforms. A multi-parameter analysis is conducted in a case study to discern the effects of specific elements on the LCOE. Expressions are formulated as functions of site-specific variables: distance to shore, water depth and annual energy production. The latter is estimated accurately by combining the power curve of an exemplar wind turbine with hindcast, site-specific wind data. The mapping shows the paramount importance of the wind climate, i.e., the resource, for the LCOE. The lowest values (∼95 €/MWh) occur where the wind resource is most abundant, i.e., the Gulf of Lion and the Aegean Sea. The highest values (>250 €/MWh) are found where the resource is scarce, i.e., around the Balearic Islands and in the North Adriatic, Tyrrhenian and Levantine Seas. Moderate values of the LCOE (130–180 €/MWh) occur off South Spain (Alboran Sea), Sardinia, Sicily and Malta, and in the South Adriatic. In addition to the local wind resource, other parameters that play a relevant role in the LCOE are those related to the production of energy (number of turbines in the wind farm and installed power), on the one hand, and to substantial sources of costs (cost of turbines and substructure), on the other, as well as the project lifetime and discount rate. These results identify hotspots for the deployment of floating offshore wind in the Mediterranean and opportunities for cost reductions, and contribute to decision-making in a region much in need of renewable energy.

1. Introduction

The production and use of energy account for the lion's share of global greenhouse gas (GHG) emissions; therefore, the development of a power system based on clean energies is a fundamental aspect in combatting climate change. The European Union has established in its Green Deal plan the ambitious goal of net-zero GHG emissions by 2050, which can only be attained through the decarbonisation of the energy sector [1].

Among all clean energies, wind power has grown significantly in recent years thanks to its technological maturity – 15.7 GW of new wind power capacity was installed in Europe in 2019 [2] and 14.7 GW in 2020 [3]. However, the scarcity of adequate onshore locations, noise nuisance and ecological impacts hinder its further development [4]. As a result, wind power has recently found in offshore locations potential areas for further development [5]. In 2019 and 2020, respectively, 3.3 GW [2] and 2.9 GW [3] of offshore wind power capacity were installed in Europe. The attractiveness of the steadier and stronger offshore wind resource is combined with lower environmental impacts [6]. Furthermore, the large available areas enable larger wind farms with fewer constraints in turbine sizing. The development of offshore wind in Europe has so far focused on the low-depth regions of the North Sea and Baltic Sea, with bottom-fixed turbines [7]. The current advances in floating offshore wind technology open up possibilities in regions of deeper waters, e.g., the Mediterranean Sea.

The development of marine renewable energy in the Mediterranean Sea is still pending. The wave energy resource [8] presents limited exploitability in the region [9], which may however be enhanced by new decision-aid tools [10] and technological solutions [11], including the downscaling of wave energy converters designed for more energetic seas [12]. Moreover, the deployment of wave energy converters in the

* Corresponding author at: University College Cork, School of Engineering and Architecture, College Road, Cork, Ireland.
E-mail address: gregorio.iglesias@ucc.ie (G. Iglesias).

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Nomenclature

AC	Alternating current
AEP	Annual energy production
CAPEX	Capital expenditures
DC	Direct current
DEA	Drag Embedment Anchor
D&C	Development and consent
ECMWF	European Centre for Medium-Range Weather Forecasts
FOWT	Floating offshore wind turbine
GHG	Greenhouse gas
HVAC	High-voltage, alternating current
HVDC	High-voltage, direct current
IRENA	International Renewable Energy Agency
LCOE	Levelised cost of energy
NOAA	National Oceanic and Atmospheric Administration
OAT	One-at-a-time
O&M	Operation and maintenance

Mediterranean Sea may be facilitated by synergetic uses for coastal protection [13] or harbour protection [14]. In any case, the vast resource of wave energy hotspots in, e.g., the Atlantic [15] can hardly be matched by any location in the Mediterranean. In this context, floating wind offers great potential for the development of marine renewable energy in the Mediterranean Sea [16]. The accurate assessment of the wind climate is fundamental for the selection of potential areas given its considerable spatial variability in the region [17].

A particular area of interest for the development of marine renewable energy in the Mediterranean Sea is its many islands, which are typically overdependent on fossil fuels, including in rather expensive forms (Diesel plants) [18]. It has been argued that, relative to onshore wind [19], marine renewable energies have a lesser impact on the landscape and tourist value of the islands, which are often their main, in some cases their only, economic drive [20]. Some of the solutions to harvest marine renewable energy are designed to integrate seamlessly in current infrastructures [21]. In Europe, research on the offshore wind potential of small islands has been carried out in, e.g., the Canary Islands [22]. Yet another avenue for marine renewable energy in the Mediterranean islands may well be combined or hybrid systems, which realise the synergies between different energy sources, such as wind-wave [23] or wind-solar [24]. This approach has been explored for islands in Tenerife [25], Fuerteventura [26] or the Aegean Sea [27]. The offshore wind and solar resources was also investigated for the Mediterranean Basin [28]. In sum, offshore wind is expected to have great applicability in the Mediterranean, and further research on the viability of new projects is much needed.

The levelised cost of energy (LCOE) is the most employed parameter to measure the viability of energy projects [29]. Defined as the ratio of all the costs incurred during the lifetime of the project to the expected energy production [30], the LCOE represents the theoretical cost of the electricity produced and is often used to compare different power generation technologies [31].

The cost of energy for bottom-fixed offshore wind has been investigated in several studies [32], considering turbines mounted on monopiles (for wind [33] and hybrid wind-wave systems [34]) or jacket structures [35], applicable in small and intermediate water depths [36]. However, the deep waters of the Mediterranean Basin impede the large-scale deployment of bottom-fixed technologies [37]. Far less constrained by water depth are floating offshore wind technologies; spar-buoys [38], tension-leg platforms [39] and semi-submersible platforms [40]. Semi-submersible platforms seem particularly promising, with fewer constraints than tension-leg platforms on the mooring system [41] and fewer requirements than spar-buoys for sheltered areas for assembly [42].

The LCOE of floating offshore projects has been studied for specific locations [43]. However, given the great spatial variability of the cost elements that define the LCOE and the vastness available for deployment, the mapping of the LCOE of floating offshore wind in the Mediterranean Sea is called for [44]. Previously, the mapping of the LCOE was proven to be a useful tool in determining potential locations for marine renewable energy projects in large-scale studies, including for wave [45], tidal [46] and offshore wind energy [47].

The LCOE of a project comprises two main elements: the costs and the energy produced. To estimate the costs of a project, expressions depending on site-specific variables, i.e., distance to shore and water depth, may be used [48]. Such a cost breakdown is a useful method to identify opportunities for cost reductions, and has not been undertaken so far for floating semi-submersible platforms in the Mediterranean Sea. As regards the energy production [49], it is typically computed using the average wind climate conditions at specific places [50]. However, the wind climate has been proven to greatly influence a number of economic indices [51], and this is only accentuated when considering the influence of climate change on wind energy [52]. In sum, an accurate, site-specific estimation of the energy production is essential to determine potential areas for the deployment of this technology [53].

In this work, the LCOE of floating offshore wind is mapped for the European and Eastern Mediterranean. A case study of a wind farm of semi-submersible platforms is presented, with a comprehensive breakdown of the costs incurred in the lifetime of the project and, where appropriate, expressions depending on site-specific variables, i.e., distance to shore and water depth. Moreover, the energy production is computed by combining the power curve of an exemplar wind turbine with hindcast data on wind speed at each grid cell. In this way, potential areas for the application of floating offshore wind are recognized along with the reasons for their attractiveness.

Furthermore, with a view to analysing how different variables influence the LCOE, a multi-parameter analysis is performed to ascertain the variables with the greatest impact on the LCOE and, thus, the viability of real-life projects, whilst identifying potential opportunities for costs reductions. Three locations with different values of the main site-specific parameters (distance to shore, water depth and wind climate) are chosen for this analysis. The variation of the LCOE of the case study with respect to 30 different parameters is analysed, and those that influence the LCOE the most are identified. Finally, different ranges of uncertainty are applied to those parameters in order to define best- and worst-case scenarios for the LCOE mapping.

The cost of energy is a fundamental aspect to determine the future development of floating offshore wind. Albeit still high in comparison with other technologies [54], great reductions are predicted [55]. In the future, the cost of energy is expected to fall thanks to economies of scale [56] (large-scale manufacturing, standardisation or upscaling of the components [57]) and optimisation of current devices [58]. In this context, assessing the effects of the various components on the LCOE and identifying potential areas for the development of this energy is essential – and therein lies the motivation for this work.

The paper is structured as follows. First, materials and methods are presented through a case study in section 2. All the costs incurred in the lifetime of the project are presented in the different subsections, along with the method to calculate the energy production. In section 3, results are presented: the LCOE mapping, with the distribution and allocation of the different costs, the multi-parameter analysis, and best- and worst-case scenarios. Finally, in section 4, conclusions are drawn.

2. Materials and methods

The levelised cost of electricity is the ratio of all the costs incurred in the lifetime of an energy project to the electricity produced. It can be understood as the price at which the electricity would have to be sold in order to break even the costs, and thus it is a fundamental parameter when studying the feasibility of energy projects. The LCOE can be expressed as

$$LCOE(x,y) = \frac{\Sigma_{i=1}^{T}(CAPEX_i(x,y) + OPEX_i(x,y))(1+r)^{-i}}{\Sigma_{i=1}^{T}AEP_i(x,y)(1+r)^{-i}}, \quad (1)$$

where the costs are subdivided into CAPEX (capital expenditures, spent prior to the functioning of the energy farm) and OPEX (operational expenditures, related to the operation and maintenance). AEP stands for annual energy production. In the LCOE mapping approach, these factors are dependant on site-specific variables, i.e., distance to shore, water depth and wind climate; and therefore they are a function of spatial coordinates (x,y). Finally, the variables r and T represent the discount rate and the lifetime of the project in years, respectively.

2.1. Case study

In this work, the LCOE is investigated through a case study: a wind farm with 200 turbines of 5 MW each (1000 MW of total installed capacity) mounted on semi-submersible platforms similar to the WindFloat concept [59]. To adequately implement Eq. (1), a breakdown of all the costs incurred in the lifetime of the project is presented by using expressions depending on site-specific variables, i.e., water depth and distance to shore. The lifetime of the project (T) is set to 20 years and the discount rate (r) to 5%. For the sake of simplicity, all the costs hereinafter are in 2020 euros (€).

The investigation and mapping of the LCOE is only relevant for eligible areas, determined as follows. First, with current technology, the installation of semi-submersible platforms is feasible in water depths within the range of 50–1000 m [60]. Second, a minimum distance to shore must be established in order to avoid visual impact and noise nuisance. However, different policies in this respect are applied in different countries [61]. E.g., Greek territorial waters (6 nm, ~11 km from the shore) present severe restrictions [62], while offshore energy projects should be located at least 8 km away from the coast in Spain [63]. In [64], it was stated that no visual nuisance was caused by wind farms situated 12 km away from the shore, on the contrary, it could lead to a slight increase in tourist attraction. Therefore, a minimum distance to shore of 12 km is established. Third, the same approach is applied to maritime areas ascribed to many different jurisdictions, so regional tax regimes and subsidies are disregarded [65]. Indeed, according to the International Renewable Energy Agency (IRENA) [66], the calculation of the LCOE typically does not consider such regional inconsistencies. Finally, due to the scale of the work, exclusion sites such as fishing areas, ship routes or natural reserves are not considered [67]. As a matter of fact, there are precedents of the installation of offshore wind farms in protected areas, i.e., the Dogger Bank in the North Sea. Since this technology is still in its early stages of development, the maritime landscape may be subject to change in future real-life, large-scale deployments.

2.2. Capital expenditures

Capital expenditures, or CAPEX, comprise the costs incurred prior to the functioning of the wind farm and those related to its decommissioning. They include costs related to the raw materials and devices, i.e., wind turbines, substructures, mooring systems and electrical infrastructure; the installation of all the components, and the development and consent procedures.

2.2.1. Development and consent

The development and consent phase (D&C) includes the environmental, met station and seabed station surveys, project management and development services [68]. Extrapolating data from bottom-fixed offshore wind, the costs considered are shown in Table 1.

Table 1
Development and consent cost allocation [69].

	Percentage of the total	Estimated cost (k€/MW)
Dev Services	70%	147
Seabed Survey	15%	31.5
Met Mast	7.5%	15.75
Environmental Survey	7.5%	15.75
	Total	210

2.2.2. Turbine & substructure

The turbine and substructure account for the biggest share of the total CAPEX [68]. In the case of bottom-fixed wind energy, the costs of the substructure are to a great extent determined by the water depth at the site. In the case of floating wind energy, and in particular semi-submersible platforms, the substructure (the semi-submersible platform) and the mooring system are considered separately, and the costs of the substructure are estimated irrespective of water depth.

The cost of the semi-submersible platform is difficult to estimate due to the novelty of the technology. An estimation for a semi-submersible platform similar to the WindFloat concept has been reported based on the material consumption and manufacturing process in [70], with a total cost of ~ 8 M€ per turbine. The price of a generic 5 MW wind turbine is set at 8 M€ [70].

2.2.3. Mooring system

The mooring system of a semi-submersible platform consists of a number of catenary lines, e.g., wire rope or synthetic fibre rope, arriving horizontally to an anchor. Due to the continuous mechanical wear and tear exerted by the seabed, these systems are typically complemented with a steel chain, more resistant to these stresses. The costs of the mooring lines are a result of extensive research and depend largely on water depth. The length of the mooring line is set approximately to 560 m for a 100 m depth and additional 150 m every 100 m depth, with an extra 50-metre-long chain [60]. As regards the anchoring system, Drag Embedment Anchors (DEAs) are considered. Although the anchoring choice may depend on the seabed conditions, DEAs are typically the preferred option due to their ability to withstand the large horizontal loads exerted by the catenary mooring lines [71]. An individual cost of 123 k€ is assumed [70].

With the assumptions made, a general expression for the costs of the mooring system ($CAPEX_{mooring}$) of a semi-submersible platform depending on water depth is

$$CAPEX_{mooring}(x,y) = n_{tur}n_{lines}[C_{anchor} + (1.5h(x,y) + 410)C_{line} + 50C_{chain}], \quad (2)$$

where $h(x,y)$ represents the water depth at the site of coordinates (x,y). The parameters n_{tur} and n_{lines} are the number of turbines and the number of lines per turbine (four in the case of WindFloat), respectively. C_{anchor} represents the cost of the individual anchor. Finally, C_{line} and C_{chain} are the costs of the mooring line and chain per unit length, respectively, which are estimated at 48 €m^{-1} and 270 €m^{-1} [60]. The bathymetry for the case study is obtained from the ETOPO Global Relief Model of the National Oceanic and Atmospheric Administration (NOAA) database, at a resolution of one arc-minute (Fig. 1). The total mooring cost for the case study is estimated using Eq. (2) and mapped (Fig. 2) in areas eligible for the deployment of the technology, following the restrictions explained in section 2.1.

2.2.4. Electrical infrastructure

Two different technologies are considered for the transmission of the electricity back to shore: High-voltage, alternating current (HVAC) and high-voltage, direct current (HVDC) [72]. The main issue with HVDC current is the fact that alternating current (AC) generated in the wind turbines must be converted to direct current (DC) for its transmission and back to AC at an onshore substation, resulting in greater fixed costs;

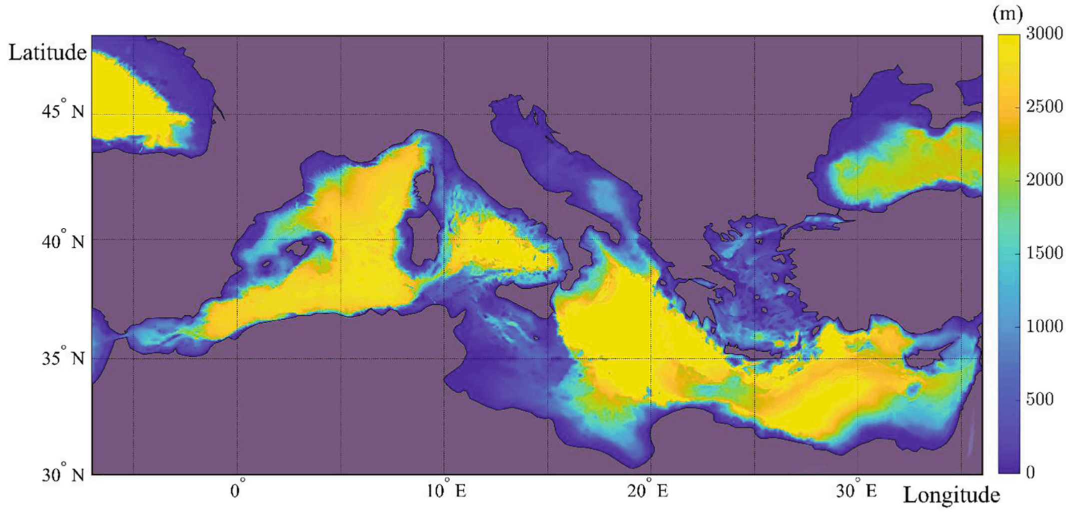

Fig. 1. Water depth (m) in the Mediterranean Sea.

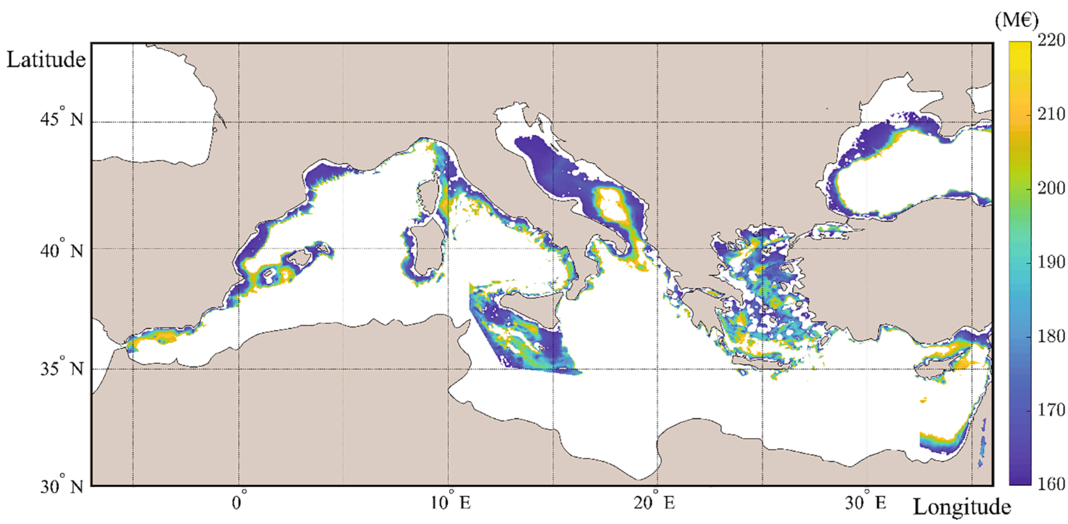

Fig. 2. Mooring cost (M€) of the case study in the eligible areas of the European and Eastern Mediterranean Sea.

however, HVDC is a cost-effective solution in projects located farther offshore [73]. In this study, the costs for both technologies are computed, and the most appropriate is chosen for each grid cell.

The inter-array cable also forms part of the total electrical infrastructure. It is considered to comprise 40 strands, each accommodating 5 turbines. The total inter-array cable length is estimated at 383.2 km, with a cost of 303.5 k€/km [60]. An estimation of the costs of both HVAC and HVDC technologies is presented considering the costs of the substations, inter-array cable and the length of the export cables. The total electrical infrastructure costs ($CAPEX_{elec}$) are estimated as

$$CAPEX_{elec}(x,y) = d(x,y)n_{ex\_cab}C_{ex\_cab} + n_{off\_sub}C_{off\_sub} + n_{on\_sub}C_{on\_sub} + L_{in}C_{in}, \quad (3)$$

where $d(x,y)$ is the distance to shore at the site of coordinates (x,y). The variables n and C represent the number and cost of the export cable, offshore substation and onshore substation (subindices *ex_cab*, *off_sub* and *on_sub*, respectively). All the values used in the case study are listed in Table 2 for both technologies. Finally, L_{in} and C_{in} are the length and cost of the inter-array cable. The total costs for the transmission of the power from the wind turbines to shore (Eq. (3)) for HVAC and HVDC technologies for the case study are represented as functions of the distance to shore (Fig. 3). It may be seen that HVDC technology becomes

Table 2
Parameters for the electrical infrastructure costs [47].

Variable	HVAC	HVDC
n_{ex_cab}	3	2
C_{ex_cab} $(M \in /km)$	2.336	1.168
n_{off_sub}	3	2
C_{off_sub} $(M \in)$	39	142.75
n_{on_sub}	–	2
C_{on_sub} $(M \in)$	–	84.35

the preferred solution beyond a certain distance, i.e., the break-even point (~72 km).Fig. 4.

2.2.5. *Installation*

This phase includes the installation of the turbine, substructure, mooring system and electrical infrastructure. These costs are difficult to estimate due to the inexistence of large-scale deployments. To overcome this, the installation cost of turbines and substructures is estimated with a simplified algorithm assuming the charter of a jack-up vessel and considering its operation and travelling times. The installation cost of

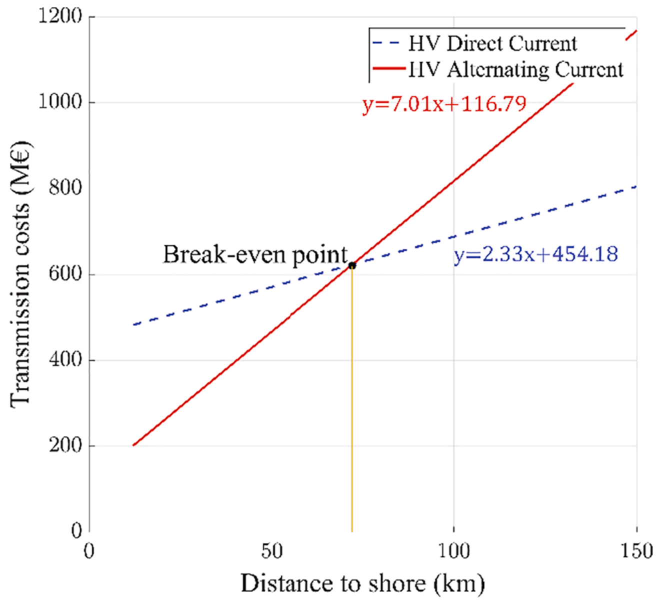

Fig. 3. Electrical infrastructure costs (M€) for HVDC and HVAC. The break-even point is estimated at ~ 72 km.

the turbines $CAPEX_{inst\_tur}$ is computed as

$$CAPEX_{inst\_tur}(x,y) = n_{tur}\left[t_{inst} + 2d(x,y){V_{vessel}}^{-1}\right]C_{vessel}{n_{tur\_trip}}^{-1}, \quad (4)$$

where n_{tur} and n_{tur_trip} are the number of total turbines and number of turbines carried per trip, respectively. The variable t_{inst} is the time spent in the installation of the turbines, C_{vessel} is the charter cost of the jack-up vessel and V_{vessel}, its speed. All values for Eq. (4) used for the case study are listed in Table 3. Additionally, an extra cost of 240 k€ per turbine is added for the installation of the mooring system [70].

The installation of the electrical components comprises the inter-array cable, export cable and substations. The cost for the installation of the export cable is estimated in the range of 382–892 k€/km [60]. In this work, an intermediate value of 637 k€ per km is assumed. As regards the inter-array cable, the installation cost is assumed to be one third of that of the export cable [74]. Finally, the installation cost of an offshore substation for semi-submersible structures is set to 30 M€ for the 1000 MW wind farm [60].

2.2.6. Decommissioning

This phase consists of a reversed installation process, with less care not to damage the components. In onshore projects, the costs related to the decommissioning operations are small as a result of the return value obtained from scrap metal. In offshore wind farms, these costs are challenging to estimate due to the lack of real-life projects having reached this phase. Typically, the estimation of the decommissioning costs is made as a percentage of the installation costs [75]. However, the return value of scrap metal has been estimated to be similar to the decommissioning costs themselves by some authors, leading to a break-even situation [47]. A detailed estimation of the final decommissioning expenses for an offshore wind project considering semi-submersible platforms is made in [70], resulting in a return value of 250 k€ per MW, which is assumed in this work.

2.3. Operation and maintenance

Operation and maintenance (O&M) costs, which comprise the hire of staff, port facilities and equipment, and the repair of damaged components, often account for a substantial share of the total costs (~25%) [76]. In offshore projects, these costs present an additional variable component that accounts for expenses related to travelling to site – time and fuel spent. The lack of large-scale offshore wind farms hinders the accurate estimation of these costs. In [60], an estimation of 138 k€ per MW is made for a project located 200 km offshore. To account for the costs related to travelling to site, a variable component of €40 per MW, year and km is considered [44].

2.4. Annual energy production

Whereas the wave resource in the Mediterranean Sea has been shown to present low values of the Wave Exploitability Index (WEI) [9], its offshore wind resource does offer potential for marine renewable energy development, whether by itself [77] or through co-located farms [78]. The spatial variability of the wind resource must be taken into account

Table 3
Parameters for installation costs of the turbines [47].

n_{tur_trip}	5
t_{inst} (**days**)	2
V_{vessel} (**km/h**)	20
C_{vessel} ($k \in /day$)	324

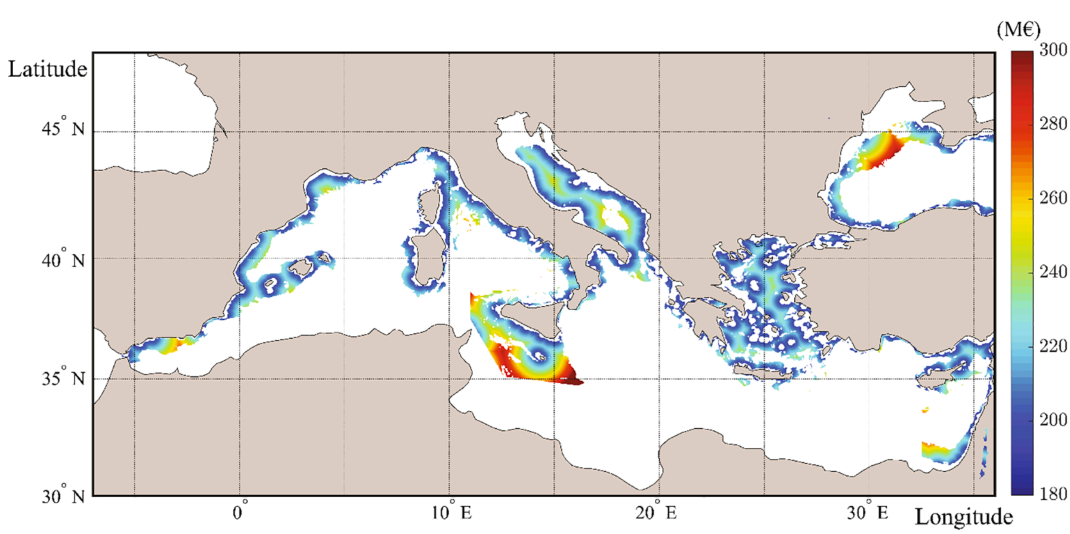

Fig. 4. Installation cost (M€) in the eligible areas of the European and Eastern Mediterranean Sea.

when considering a large-scale mapping [79]. In this work, the annual energy production (AEP) of the wind farm was computed at each grid cell using hindcast data of wind speed in combination with the power curve of an exemplar wind turbine. For this purpose hourly data of wind speed at an elevation of 100 m were obtained from the ERA-5 database of the European Centre for Medium-Range Weather Forecasts (ECMWF) [80]. As a reference, the mean wind speed at 100 m height is computed using 20 years' worth of data (2000–2019) (Fig. 5). As for the power curve, the REpower 5 MW wind turbine was used as the exemplar turbine (rated power at 11.4 ms^{-1}, cut-in at 3 ms^{-1}, cut-out 25 ms^{-1}, hub height 95 m) [81].

To account for different losses and operating times, a performance factor is applied to the energy production. The average time a single wind turbine is able to operate (availability time) is set at 94% [75]. Losses concerning the electric system are estimated at 1.8% [70], while aerodynamic losses are assumed to be 7% [82]. Finally, an additional 3% is applied to account for other losses, such as hysteresis, power curve degradation or the diminishing of power performance [75].

Combining 20 years' worth of data (2000–2019), i.e., the lifetime of the project, with the power curve of the exemplar wind turbine and the aforementioned losses at every single time step, the annual energy production is computed (Fig. 6).

3. Results and discussion

The installation of offshore technologies is conditioned by the bathymetry. In the Mediterranean Basin, large water depths, which preclude the large-scale deployment of bottom-fixed wind turbines, occur not far from the coast (Fig. 1). By contrast, extensive areas are found to be eligible for floating offshore wind turbines (FOWTs), including much of the Adriatic and Aegean Seas, as well as areas off Sicily, Malta, Cyprus and the Balearic Islands (Fig. 2). Non-eligible areas for floating offshore wind, following the criteria explained in section 2.1, are not coloured on the map.

Using the expressions from section 2.2, the total CAPEX is mapped in the European and Eastern Mediterranean Seas (Fig. 7). It is apparent that the distance to shore is the main variable driving the costs. The lowest capital expenditures (~4100 M€) occur systematically nearshore, whereas the highest (~5000 M€) are found far offshore – the reason being that the costs of installation and, above all, electrical infrastructure depend crucially on the distance to shore. Indeed, the costs related to the electrical infrastructure were found to constrain the deployment of floating wind farms farther offshore – even though the two technological options (HVAC and AVDC) were considered in the analysis.

In comparison, the effects of water depth on the total costs are less significant. The water depth only affects one aspect of the cost of the mooring system, namely the cost of the mooring lines. However, this effect on the cost of the mooring lines is overshadowed by other aspects of the mooring system that are independent of water depth, e.g., anchors or steel chain. As a result, the costs related to the mooring system do not vary as much as might be expected from the shallowest (160 M€) to the deepest sites (220 M€). Within the eligible range (50 – 1000 m), water depth is not such an important constraint for floating technologies as it is for bottom-fixed.

3.1. *Levelised cost of energy mapping*

Using the methods presented in section 2, the levelised cost of energy was computed and mapped for the eligible areas of the European and Eastern Mediterranean Sea (Fig. 8). For all the influence of the distance to shore, the resource is still the most important factor in the final value of the LCOE – ultimately proving the need for an accurate estimation of the annual energy production. In other words, the considerable spatial variability of the wind climate determines the annual energy production, i.e., the income, at a particular site. For this reason, the lowest values of the LCOE (~95 €/MWh) occur where the annual energy production is highest, i.e., where the resource is most abundant: in the Aegean Sea and the Gulf of Lion (Fig. 6). At the other end of the spectrum, the highest values of the LCOE (>250 €/MWh) occur where the annual energy production is lowest, i.e., where the resource is scarcest: around the Balearic Islands and in the North Adriatic, Tyrrhenian and Levantine Seas. Finally, moderate LCOE values (130–180 €/MWh) are found in South Spain (Alboran Sea), off Sardinia, Sicily and Malta, and in the South Adriatic Sea.

It is apparent, therefore, that the correct assessment of the resource is of paramount importance for the viability assessment of future projects. The areas with the greatest potential for the development of floating offshore wind have in common an abundant resource. The distance to shore or water depths are comparatively less important.

3.2. *Multi-parameter analysis*

To assess how the different factors considered affect the final value of the LCOE, a multi-parameter analysis is presented for three sites with different characteristics and values of the LCOE (Fig. 8). The first site (P1: 37.25°N, 25.75°E), near the island of Naxos in the Aegean Sea, is relatively close to shore and presents a great AEP (Fig. 6) and, as a result, a low LCOE. The second site (P2: 35.50°N, 15.75°E), east of Malta, is far

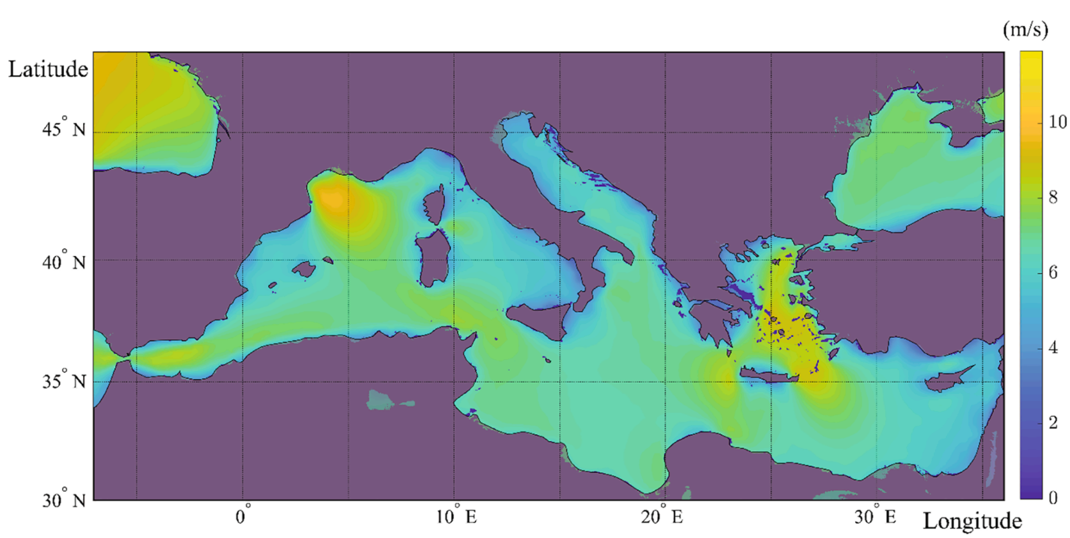

Fig. 5. Mean wind speed (m/s) at 100 m height in the Mediterranean Basin.

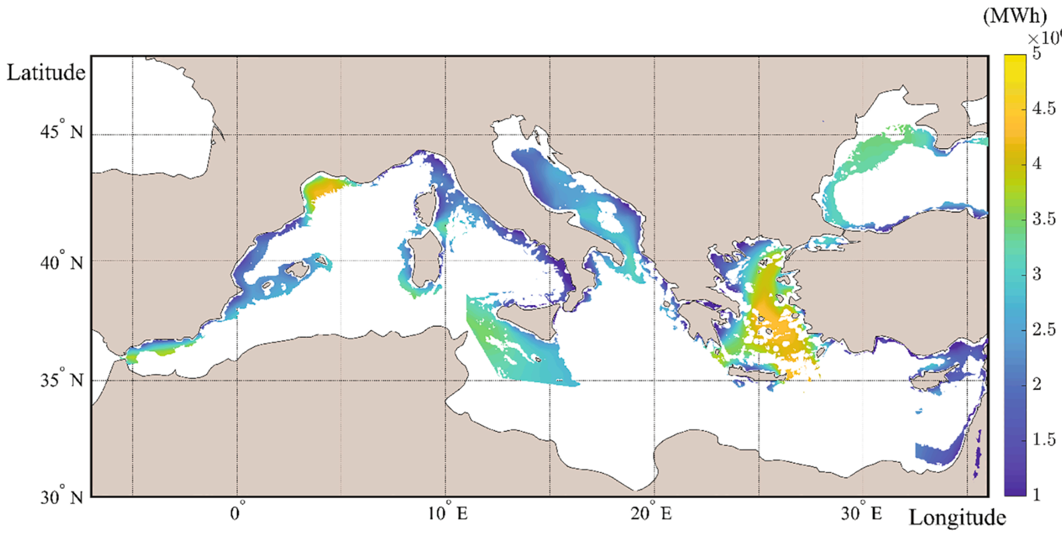

Fig. 6. Annual energy production (MWh) in the eligible areas of the European and Eastern Mediterranean Sea.

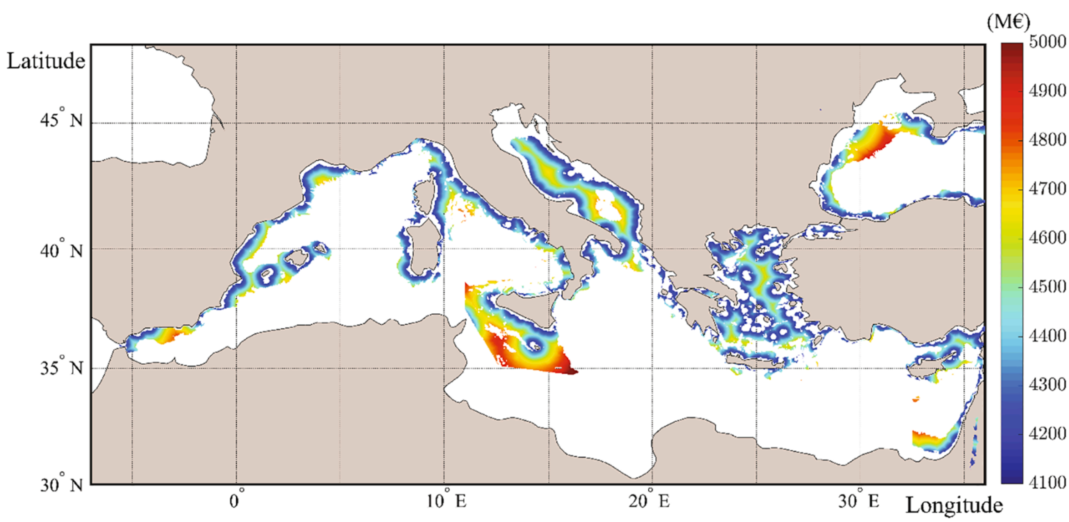

Fig. 7. Total CAPEX (M€) in the eligible areas of the European and Eastern Mediterranean Sea.

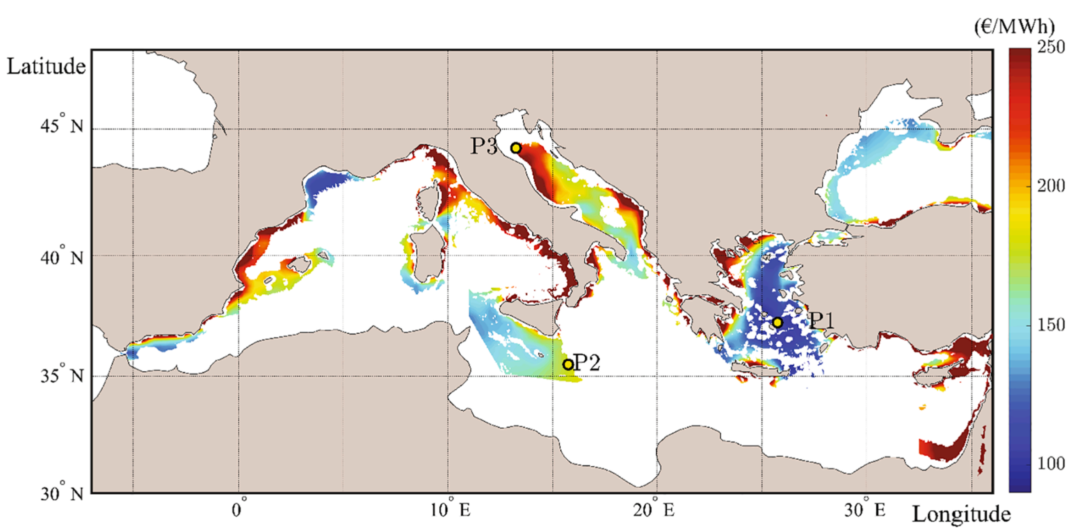

Fig. 8. LCOE (€/MWh) in the eligible areas of the European and Eastern Mediterranean Sea. The sites selected for the multi-parameter analysis (P1, P2 and P3) are indicated with circles.

offshore, with a moderate LCOE value. Finally, the third site (P3: 44.25°N, 13.25°E), in the North Adriatic, is relatively close to shore but has a low AEP, resulting in a high LCOE.

A breakdown of all the costs incurred in the lifetime of the project is presented for the three sites considered (Fig. 9). The costs of the turbine and substructure account for the biggest share of the total (~50%) [83]. The costs related to the mooring system are of a lesser order of magnitude, and thus of little significance in the greater picture. The costs related to the electrical infrastructure are greatly affected by the distance to shore – much more so than the installation cost or the OPEX. As a result, site P2 (which is located farthest offshore) presents the largest costs.

Fig. 10 presents the effects on the final LCOE value of a number of parameters: the costs of the turbine/substructure and OPEX (which dominate the total costs), number and nominal power of the turbines, lifetime of the project and discount rate. The One-at-a-time (OAT) method [84], which consists in varying one parameter while maintaining the others fixed, is used to perform the analysis at the three sites considered. Therefore, the effects of each single element on the final value of the LCOE are evaluated. With the OAT method, more precise values obtained in future works or eventual cost reductions can be easily applied to the results presented in this work.

It is found that variations in the cost of turbines, the fixed component of the OPEX and discount rate result in linear changes in the LCOE – due to the similarity between the costs of the turbine and the substructure, the latter is omitted. Variations of 50% in these variables produce changes of ~ 14% in the LCOE, with a positive rate of change. On the contrary, variations in the number and nominal power of the turbines and the lifetime of the project have a non-linear effect on the LCOE, with a negative rate of change – a negative change in the variables results in an LCOE increase. It is noteworthy how variations in the number of turbines have a more or less pronounced effect depending on the point considered. Indeed, decreasing the number of turbines has a greater effect at sites farther offshore (P2). A decrease of 50% causes the LCOE to increase 17% at P2, a much greater increase than at P1 or P3; whereas a 50% increase results in a ~ 5% reduction.

Importantly, the turbine nominal capacity influences the LCOE the most – a 50% reduction in the turbine nominal power produces a 70% increase in the LCOE, whereas a 50% increase results in a 20% drop. Nonetheless, variations in the nominal power of the turbines are inherently linked to the use of larger devices and thus to greater turbine

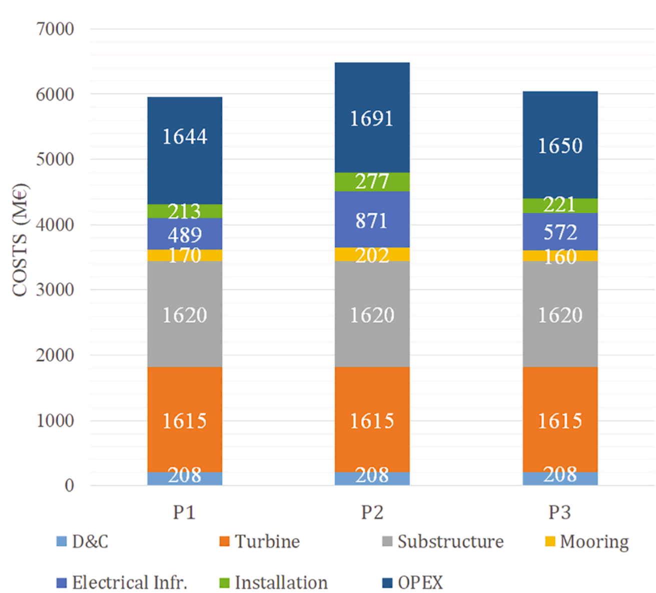

Fig. 9. Cost (M€) breakdown at selected sites (P1, P2 and P3). In white, costs (M€) of each element.

costs, a fact that is not considered in the OAT method. Notwithstanding, given that the LCOE varies nonlinearly with respect to the turbine nominal power but linearly with respect to the cost of turbines, there is much room for LCOE reductions in future.

As regards the lifetime of the project, the step curve representation is chosen, for this variable generally takes on natural numbers (Eq. (1)). The lifetime of the project also shows a great influence on the final values of the LCOE, which is reasonable given that it is the length of time available to amortise the CAPEX – costs incurred mostly before the operation of the wind farm.

On the downside, the nonlinearity of the relation between the LCOE and the above-mentioned variables, (number of turbines, turbine nominal power and project lifetime) is accompanied by a flattening of the curves – beyond certain values, the capacity to reduce the LCOE by modifying these variables will be less significant. In any case, the relation between the LCOE and these variables is a fundamental aspect in the design of future projects.

The effects of all the 30 parameters considered in this work are presented in Table 4. It may be seen that the variables that most influence the LCOE are those depicted in Fig. 10. Among all the costs depending on the distance to shore, the costs of the export cable are those that most affect the LCOE. Since HVAC technology presents low fixed costs but is very sensitive to distance to shore, changes in the cost of the export cable – represented by the slope of the function in Fig. 3 – are decisive for its application. Lowering the costs of the export cable in HVAC technology makes it more appropriate for locations farther offshore, e.g., P2, whereas augmenting these costs makes HVDC more appropriate. On the contrary, HVDC technology presents high fixed costs, and a decrease in these would make this technology more appropriate for nearshore sites such as P3.

Finally, the annual energy production dominates the final value of the LCOE. The changes in the LCOE resulting from the wind farm availability and aerodynamic losses vindicate the importance of an accurate estimation of the energy production.

3.3. Best- and worst-case LCOE scenarios

The multi-parameter analysis of the previous subsection showed how different factors affect the final value of the LCOE from a theoretical point of view, thereby identifying the important factors for the optimization of an energy project and providing useful information for future cost reductions. However, due to the novelty of floating offshore wind technology and lack of large-scale projects, a degree of uncertainty is inevitable. Therefore, in the following different uncertainty ranges are considered for the parameters that have the greatest influence on the LCOE. This study is conducted through best- and worst-case scenarios considering different uncertainty ranges specified by designers and common design parameters of the project (Table 5).

The lowest values of the LCOE in the best-case scenario (Fig. 11), ~75 €/MWh, occur in the Gulf of Lion and the Aegean Sea. In this scenario, relatively low LCOE values (~110 €/MWh) can also be found in locations with much higher values in Fig. 8, i.e., South Spain, off Sardinia, Sicily and Malta, and South Adriatic Sea, thus presenting great potential for future offshore wind development. In stark contrast, the worst-case scenario (Fig. 12) depicts a situation in which the lowest values of the LCOE are ~ 145 €/MWh, not ideal for the application of the technology. At the other extreme, the maximum values surpass 400 €/MWh.

4. Conclusions

The levelised cost of energy for floating offshore wind in the European and Eastern Mediterranean Sea was investigated and mapped. The approach was illustrated through a case study, with a focus on semi-submersible platforms. A comprehensive breakdown of all the costs incurred in the lifetime of a floating offshore wind project was

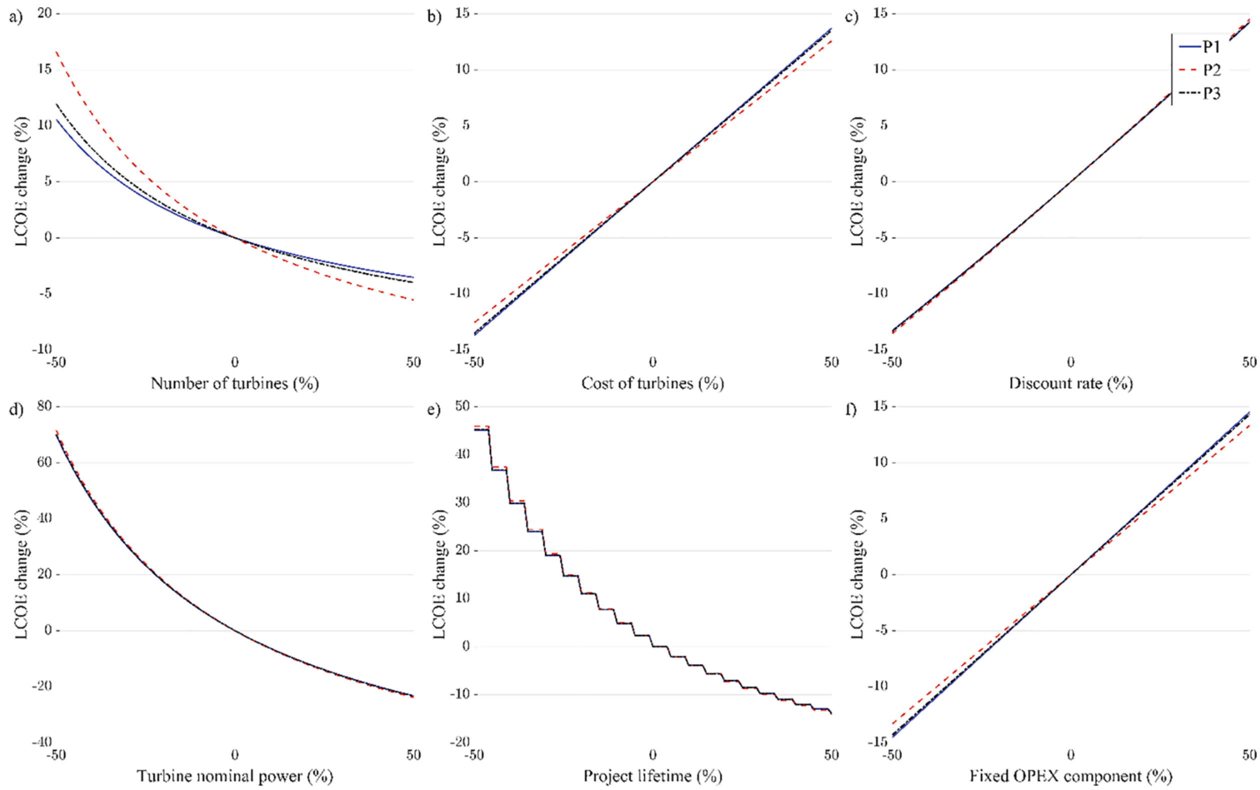

Fig. 10. LCOE change (%) resulting from the variation of: number of turbines (a), cost of turbines (b), discount rate (c), turbine nominal power (d), project lifetime (e) and fixed OPEX component (f) .

Table 4
LCOE change (%) resulting from the variation (±50%) of different parameters involved in the computation of the LCOE.

	P1		P2		P3	
	−50%	50%	−50%	50%	−50%	50%
Number of turbines	10.6%	−3.5%	16.6%	−5.5%	12.0%	−4.0%
Cost Turbines	−13.7%	13.7%	−12.6%	12.6%	−13.5%	13.5%
Cost Substructure	−13.8%	13.8%	−12.7%	12.7%	−13.6%	13.6%
Cost D&C	−1.8%	1.8%	−1.6%	1.6%	−1.7%	1.7%
Turbine nominal power	69.8%	-23.3%	71.6%	-23.9%	70.2%	-23.4%
Project Lifetime	45.1%	−13.9%	45.9%	−14.2%	45.2%	−13.9%
Discount rate	−13.3%	14.2%	−13.5%	14.5%	−13.3%	14.3%
Anchor cost	−0.8%	0.8%	−0.8%	0.8%	−0.8%	0.8%
Fixed OPEX component	−14.5%	14.5%	−13.3%	13.3%	−14.3%	14.3%
Variable OPEX component	−0.2%	0.2%	−0.5%	0.5%	−0.2%	0.2%
Inter-array length	−1.7%	1.7%	−1.5%	1.5%	−1.6%	1.6%
Days install turbine	−0.3%	0.3%	−0.2%	0.2%	−0.3%	0.3%
Cost jack-up	−0.3%	0.3%	−0.3%	0.3%	−0.3%	0.3%
Cost installation mooring	−0.4%	0.4%	−0.4%	0.4%	−0.4%	0.4%
Cost inst. export cable	−0.2%	0.2%	−0.6%	0.6%	−0.3%	0.3%
Cost inst. inter-array cable	−0.7%	0.7%	−0.6%	0.6%	−0.7%	0.7%
Cost installation substation	−0.3%	0.3%	−0.2%	0.2%	−0.3%	0.3%
Cost offshore substation AC	−1.0%	1.0%	0.0%	0.0%	−1.0%	1.0%
Cost offshore substation DC	0.0%	0.0%	−2.2%	2.2%	−0.5%	0.0%
Cost export cable AC	−2.2%	2.2%	−2.9%	0.0%	−2.8%	1.9%
Cost export cable DC	0.0%	0.0%	−2.3%	2.3%	0.0%	0.0%
Cost onshore substation DC	0.0%	0.0%	−1.3%	1.3%	0.0%	0.0%
Cost inter-array cable	−1.0%	1.0%	−0.9%	0.9%	−1.0%	1.0%
Cost decommissioning	1.4%	−1.4%	1.3%	−1.3%	1.4%	−1.4%
Cost mooring line	−0.2%	0.2%	−0.5%	0.5%	−0.2%	0.2%
Cost mooring chain	−0.4%	0.4%	−0.3%	0.3%	−0.4%	0.4%
Wind farm availability	−3.1%	3.3%	−3.1%	3.3%	−3.1%	3.3%
Electrical Losses	−0.9%	0.9%	−0.9%	0.9%	−0.9%	0.9%
Aerodynamic losses	−3.6%	3.9%	−3.6%	3.9%	−3.6%	3.9%
Other losses	−1.5%	1.6%	−1.5%	1.6%	−1.5%	1.6%

Table 5
Uncertainty values of different components used in the computation in best- and worst-case LCOE scenarios [83].

	Best	Worst
Number of turbines	50%	−50%
Cost turbines	−8%	15%
Cost substructure	−20%	20%
Discount rate	−20%	20%
Project lifetime	25%	−25%
Fixed OPEX component	−10%	10%

presented, with expressions depending on site-specific variables – the distance to shore and water depth.

Importantly, the electricity production over the lifetime of the project was calculated with hindcast data of wind speed in combination with the power curve of an exemplar wind turbine. In this manner, an accurate estimation of the electricity produced was performed considering the specific wind climate of each grid cell, thereby accounting for the considerable spatial variations of the wind energy resource in the Mediterranean.

The cost breakdown was compared for three sites of different characteristics (wind climate, distance to shore, water depth), and the role of different parameters in the final value of the LCOE was studied following the One-at-a-time (OAT) method – varying one parameter while the rest remain constant.

Some of the values used in this work are subject to uncertainty due to the novelty of the technology and lack of real-life, large-scale deployments. To take this into account, different ranges of uncertainty were applied to the parameters that most affect the LCOE. On this basis, best- and worst-case scenarios were considered and mapped.

The main site-specific variable controlling the LCOE was found to be the energy production (which depends on the local wind resource) rather than the distance to shore or water depth. Although the costs are greatly influenced by the distance to shore – not so much by the water depth – this effect is overshadowed by the spatial variability of the wind resource. Hence, the lowest values of the LCOE are located where the wind resource is best, i.e., the Gulf of Lion and the Aegean Sea: approximately 95 €/MWh (or as low as ~ 75 €/MWh in the best-case scenario). On the contrary, the highest values of the LCOE (>250 €/MWh) occur in areas with little wind resource, i.e., near the Balearic Islands or in the South Adriatic, Tyrrhenian and Levantine Seas. Moderate values of the LCOE, in the range 130–180 €/MWh (~110 €/MWh in the best-case scenario), are found in South Spain, off Sardinia, Sicily and Malta, and in the South Adriatic Sea.

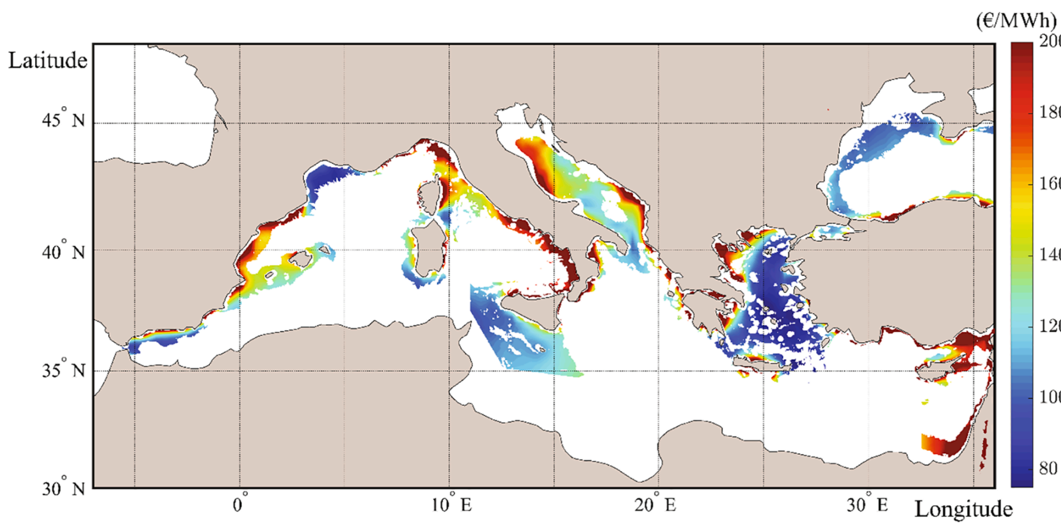

Fig. 11. LCOE (€/MWh), best-case scenario (Table 5).

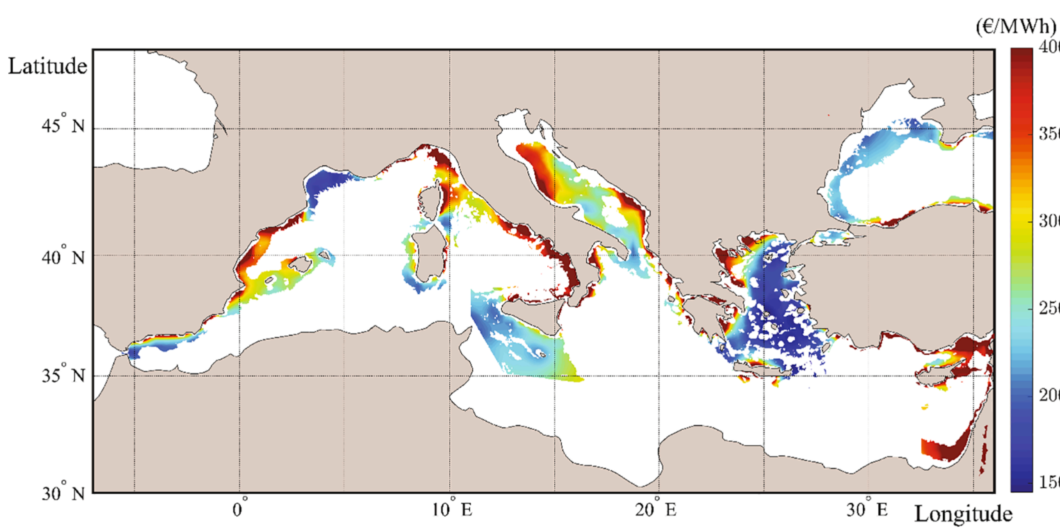

Fig. 12. LCOE (€/MWh), worst-case scenario (Table 5).

The breakdown of the costs indicates that the biggest share of the total expenses is related to the cost of the turbines, the corresponding substructures and OPEX. The multi-parameter analysis showed, therefore, that these are the costs that most influence the LCOE. The variables related to the production of electricity of the wind farm, e.g., the number of turbines, their nominal power and the project lifetime, are also of importance. The nonlinear relationship of these variables with the LCOE dictates that, below certain values, the cost of energy increases drastically. On the other hand, beyond a certain value, large increases in these variables lead to small reductions in the LCOE.

The lack of real-life floating offshore projects hinders the accurate estimation of the cost of energy. This is inevitable when dealing with a nascent sector, such as floating offshore wind energy. Areas with potential for the deployment of floating offshore wind in the Mediterranean were identified in the large-scale LCOE mapping presented in this work. The breakdown of the costs and the multi-parameter analysis performed can help to identify opportunities for cost reductions and facilitate decision-making for new projects. In the future, large reductions in the cost of floating offshore energy may be expected as economies of scale kick in, through large-scale manufacturing, standardisation or upscaling of the turbines and components.

CRediT authorship contribution statement

A. Martinez: Conceptualization, Methodology, Formal analysis, Investigation, Data curation, Writing - original draft. **G. Iglesias:** Conceptualization, Methodology, 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.

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