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Review article

A Review and Analysis of the Uncertainty Within Cost Models for Floating Offshore Wind Farms

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ABSTRACT

The development and deployment of offshore wind farms in the last decade have seen a dramatic increase, now totalling 743 GW globally (Global Wind Energy Council, 2022). This rapid increase is expected to further continue now with the potential to explore deeper sites with the adoption of floating offshore platforms. Proof of this growth has recently been seen with an impressive 60% of the 25 GW Scotwind leasing sites planning to install floating platforms in the next ten years (Crown estate, 2022 [1,2]). One main disadvantage of the advancement offshore is uncertainty and the potential increase in costs due to more complex structures and greater distances to shore. The cost increase for floating platforms is expected to be two to three times more expensive than traditional fixed support structures (Eric Paya, 2020). Thus, this work aims to review existing analytical cost models found within the literature to best determine their level of accuracy and compare the assumptions which have been made. Leading on from this review, a collection of all data found in the reviewed literature is presented, which leads to a data analysis that determines the variation across literature and the potential causes. Assessing this literature shows a wide range of model considerations, often leading to assumptions with little or no data to be validated against. Hence, high levels of variation and a lack of consensus on the cheapest floating platform were noted. All aspects of costs related to floating offshore wind systems vary heavily throughout the literature.

1. Introduction

Since the world's first offshore wind power project was installed 30 years ago in Vindeby, Denmark, the industry has come a long way [3]. The main driver behind the offshore wind industry has been to move away from fossil fuels and adopt a more sustainable lifestyle utilising natural, renewable sources such as wind. To ensure decarbonisation, legally binding international agreements have been signed: the 2008 Paris Agreement (COP21) was signed by 192 parties to keep the world's average temperature within 2 degrees of what had been experienced before the industrial revolution [4] - which has prompted these governments to accelerate the rate of deployment of renewable energy devices. The UK is already a world leader in the offshore wind sector, with the largest offshore capacity totalling 10.5 GW, which is expected to grow rapidly in the coming years [1,2,5,6]. The government has pledged that all homes in the UK will be powered by offshore wind by 2030, creating a target of 40 GW of installed capacity [7]. The end goal for the UK is to be net zero by 2050, with Scotland aiming to achieve the same goal by 2045 [8].

In order to install capacity at such a rapid rate, there is a considerable demand to explore all sites available. As expected, nearshore sites were the first to be explored, with around 77% of current installations in Europe utilising monopile foundations, which are limited to depths of around 40m [9]. However, it has been expressed that the feasible upper limit of water depth is 70 m for fixed platforms [10]. The seas around China, similar to installations around Europe, also utilise monopile and jacket structures due to their shallow water characteristics, applying to both near and further distance to shore [9]. There are however, also conditions where near-shore sites are only deep water where there is a small Continental shelf, examples of this are Japan and the western coasts of North and South America [11]. As more and more nearshore sites with shallow water depths are exploited, the only option is to move to deeper, further field sites.

It was estimated by the Scottish government that around 80% of Europe's wind resource is in waters deeper than 60 m, further highlighting the great potential the wind sector has to provide green energy [12]. As the water depth increases, traditional fixed foundations become much more difficult to design and install, and they may become economically unfeasible or at least very challenging [13]. It is however estimated that, due to harsher environments, increased turbine size and

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more complex structures, the CAPital EXpenditure (CAPEX) could be doubled in comparison to fixed turbines [14,15]. The increased distance from shore, fewer weather windows, and requirement for larger vessel capacity are also predicted to have an impact on Operations and Maintenance (O&M) and installation costs [16]. It is, however, due to such harsh operating environments that a stronger and more consistent wind resource can be found, allowing the Annual Energy Production (AEP) and the load factor to be increased, making Floating Offshore Wind Turbines (FOWTs) potentially competitive in terms of Levelised Cost of Energy (LCoE) [17–19].

An important parameter of any technology is cost. By quantifying the cost in generic terms such as LCoE, different energy types can be easily compared and proven feasible. The first step of finding the LCoE is being able to quantify the cost accurately. This is key in identifying the cheapest technology, allowing it to be competitive or better than existing energy resources. However, cost modelling is something which has been sparsely explored in terms of floating offshore wind turbines. Hence this work aims to review the cost models presented in the literature, determining any gaps, uncertainty, assumptions, and weaknesses in each model. This will allow the authors to determine what needs to be done to further improve existing cost models, implement these findings, and create a model which can best determine the cheapest platform for any given site.

This paper is organised as follows. In Section 2, an analytical review is carried out, firstly detailing the methodology to find appropriate literature, followed by a review of the market growth and technology advancements. In Section 3, the cost model literature is reviewed. Section 4 includes a data analysis which compares the literature cost models, Section 5 details future work, and finally, Section 6 draws conclusions on the main findings.

2. Literature review approach

2.1. Methodology to find appropriate literature

In order to carry out a comprehensive literature review, works related to cost modelling for offshore wind turbines were found and assessed. A range of keywords were used to find this literature, including cost model, floating offshore wind, offshore wind turbine, LCoE of floating offshore wind, wind turbine cost model, and offshore wind turbine cost model. Once the related literature was identified, the author started highlighting more papers found within the references, thus discovering the main authors in this area of work. From this research, it has been made clear that this area is relatively new, with the majority of papers published in the last 10 years and an increasing number of publications over time, as reported in Fig. 1 which highlights this trend.

A total of 76 papers were collected for the literature review. Inherently not all of these papers would be appropriate, hence filtering criteria was set to select the most relevant papers. These criteria were: appropriate content, number of citations and year published, journal, impact factor, and citescore.

The main aim of this research was to review cost models for floating offshore wind turbines. Therefore, the first step was to remove any papers which did not have a cost model. During the literature review, it was observed that there are three types of cost models used: (i) analytical, (ii) probabilistic, and (iii) audited data models. The analytical method is the most popular, using formulae to find the cost of each system/process related to the offshore wind farm. The focus of the review will be on analytical cost modelling. The probabilistic approach fits a probability curve to historical data related to wind farm cost, allowing the cost to be determined. Papers which use this approach can be found here [20–22]. Using an audited cost model technique to determine the cost relies heavily on existing data similar to the probabilistic method. However, the available data used in these pieces of research are all for fixed offshore turbines, due to the lack of maturity in the floating wind industry. For instance, Aldersey et al. [23] utilise this technique for cost modelling, using audited accounts to try and better determine the LCoE of different energy resources. This led to three sub-filters. Firstly, papers without cost models, secondly if they used a probabilistic approach to find the cost and lastly if they used an audited data method to predict costs. Since the probabilistic method and data technique are different in methods to calculate the cost they are not comparable to the analytical method allowing them to be discarded from this work.

The following criterion analyses the citation number, where a higher citation number indicates better visibility and impact. However, it is acknowledged that there are instances where papers can still be relevant, timely, and of good quality despite having lower citation counts. Therefore, the year of publication was also taken into consideration. Newer papers are expected to have fewer citations due to their recent publication. To account for this, the average citations per year was used as an indicator. Additionally, the author considered the journals in which the works were published by examining their impact factor, citescore, and the author's opinion on the paper's usefulness. This evaluation involved reading the paper and comparing the cost models to those in journals with high-impact factors and citescores. If the author felt they were comparable then they were also included in the review. Table 1 highlights the most common journals in which the research was published, along with their relevant scores accurate for 2020.

3. Offshore wind overview

3.1. Wind technology development

The global energy consumption each year is roughly 23,900 Terawatt-hours, according to statistics from 2019 [24]. It is estimated that 20% of the total wind power globally could account for around 123 Petawatt hours [25]. With this in mind, it is clear that harnessing wind energy is an important step in becoming a greener planet [15]. The wind sector has grown rapidly, creating a strong presence on and offshore. The first wind turbine used to create electricity was built in 1887, Marykirk, Kincardineshire, by Professor James Blyth [26]. Since then wind turbines have evolved to the most commonly known configuration today: horizontal axis, three-bladed, variable speed, pitch-controlled turbines. The story started firstly onshore, where the turbines could be engineered in the most efficient manner to maximise electrical production from the wind, this allowed learning, standardisation of parts and more importantly a decline in cost. There are a few issues with onshore sites, particularly visual impacts, noise and transportation. To avoid such friction with wind energy, a solution was to install them offshore and have been since 1991 [27]. Since then developments in engineering capabilities have allowed wind turbines to quickly increase in size, in terms of rotor diameter and power production. Fig. 2 shows this increase and future predictions, it can however be noted that the industry is already at the 15 MW prototype stage, a lot earlier than this Figure predicts. As wind technology advances, countries around the world have been increasing their capacity. In 2020, 16% of electricity produced in Europe came from the wind resource [28]. A total of 220 GW of capacity is now installed over Europe, 70% coming from 7 main contributors: The Netherlands, Germany, Norway, Spain, France, Turkey, and Sweden. Within Europe, offshore wind accounted for 20% of new installations, connecting 2.9 GW of capacity to the grid [28]. China has made its presence clear in recent years with the largest capacity installed of 100 GW in 2020, despite the COVID-19 pandemic [29]. Across Europe 3.7 GW of offshore wind turbines are expected to be installed, with the UK paving the way with a substantial 2 GW capacity. Looking to the future, it is predicted that between 2021 and 2025 a further 29 GW offshore capacity will be installed in Europe, 15 GW of which in the UK [28]. The growth across Europe can be highlighted in Fig. 3.

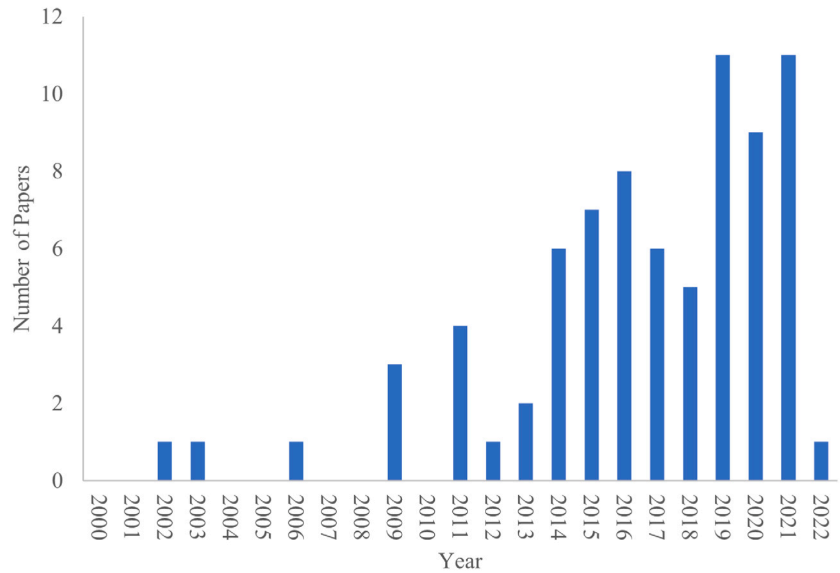

Fig. 1. The literature published per year relevant to the research area.

Table 1
Journals and their given performance indicators for 2020.

Journal	Papers' number	Impact factor	CiteScore
Renewable and Sustainable energy reviews	2	14.982	30.5
Applied Energy	1	9.746	17.6
Energy Conversion and Management	1	9.709	15.9
Journal of Cleaner Production	1	9.297	13.1
Renewable Energy	6	8.001	10.8
Energy	1	7.147	11.5
Sustainable Energy Technologies and Assessments	2	5.353	5.9
Energy Sources, Part B: Economics, Planning and Policy	1	3.205	5.2
Energies	1	3.004	4.7
Marine Science and Engineering	2	2.458	2
Energy Procedia	2	N/A	4.4
Other (e.g., Technical Report, Thesis)	5	N/A	N/A
Total	25		

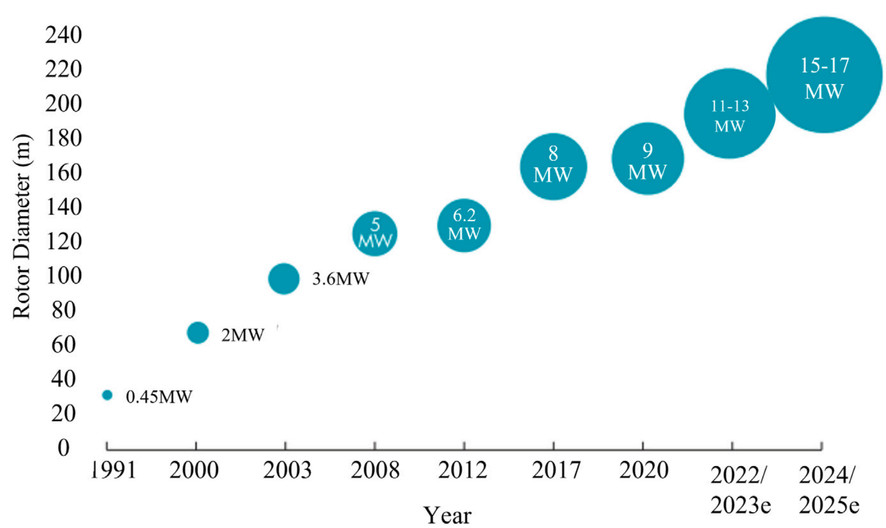

Fig. 2. Growth in turbine size and power [30].

In order to keep expanding offshore wind further afield, sites will have to be utilised as potential nearshore sites are becoming fewer. Compared to fixed foundations, floating options provide flexibility. The main advantage of a floating foundation is the ability to operate in deeper water where the resource is stronger, and more consistent, with little to no visual impacts. The possibility of transporting the fully assembled wind turbine on its platform, then transported by a tug arises, with the hope of reducing installation costs. The same concept

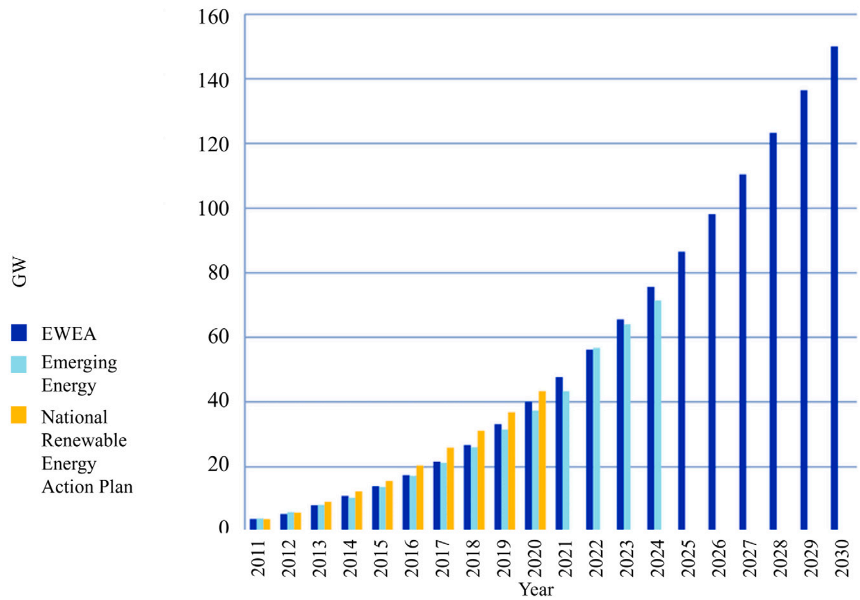

Fig. 3. Installed and predicted installations across Europe in the coming years [31].

can be echoed in the maintenance strategy, where it is expected that tow to port will become an option. This option will allow major repairs to be carried out at port which is cheaper and safer. Unlike fixed platforms floating only requires anchors which has a less negative effect on marine life [32]. Decommissioning of wind farms is more than ever becoming a predominant topic of conversation as the first farms approach the end of their life span. Due to the ease of removal, it is expected that specialised vessels will no longer be required and it will be a much cheaper clean-up process [13].

With advantages there are always disadvantages, the main drawback is the harsh environment which makes it difficult to install and operate in, leading to a high likelihood of increased failure rates [32, 33]. The cost and difficulty of carrying out O&M are also expected to be greater with a reduced number of available weather windows due to the harsh environment. The CAPEX of the offshore wind turbine is also expected to be around double that of the same turbine in shallower waters [14,15]. Increasing the distance offshore increases the length of export cable to transport energy. This has cost implications as well as increased losses, making traditional high-voltage AC (HVAC) no longer the most feasible option. At around 50 km offshore, it is predicted that high voltage DC is more cost-effective due to its higher efficiency [32,34]. Using greater wind resources creates the possibility of installing larger turbines, however, this can cause issues at port due to handling capabilities. The floating structures can also pose an issue for port handlers due to their large size and sometimes awkward shape [32]. These challenges are, however, as previously explained expected to be rewarded with a better capacity factor and therefore energy yield.

There are currently three floating wind farms which are operational, Hywind, and Kincardine, both in Scotland and WindFloat Atlantic in Portugal. Hywind is located off the coast of Scotland, installed in 2017, consisting of floating SPAR substructures. This site has an installed power of 30 MW, with a record-breaking average capacity factor of 54%, making it the best performing offshore wind farm [35]. Benefiting from the Renewable Obligation Certificates (ROCs), Hywind managed to achieve a LCoE of GBP180/MWh [14].

3.2. Technology review

Floating platforms have been used in the last 60–70 years for offshore oil and gas (O&G) platforms, meaning the technology is already proven, with lessons learnt over the years [36]. It is for this reason that a number of floating platform typologies have been adopted from oil and gas to floating offshore wind. There are three main categories of floating offshore platforms: SPAR, Semi-submersible and Tension Leg Platform (TLP). Fig. 4 provides a graphical representation of those categories.

Semi-submersibles have a large waterplane area, which helps provide the necessary stability to remain upright. As the platform is inclined, the leeward side of the platform has a greater submerged volume, creating a greater buoyancy force acting on the volume, restoring the platform to equilibrium. Due to this, these structures may afford to have a shallow draft [32,37]. The configuration of the semi-submersible in Fig. 4, highlights a number of columns joined together. This typology does not need a solid water plane area, it can in fact be built based on a number of columns joined together by bracings, so long as they are spread out in a manner which creates a large enough second moment of waterplane area, to provide the restoring force. Heave plates are typically used at the bottom of the column to reduce vertical motions [37]. Due to its sometimes complex geometry, it has a higher level of difficulty and complexity to fabricate, which will be reflected in terms of cost. Cost benefits are predicted considering the structure should have a lower overall structural mass [32]. Improved stabilisation can be achieved using active ballast to counteract the inclining moment created by the wind [37]. Due to the stability of the platform it can be built onshore and then towed to the site using tugs, making it fairly easy and inexpensive to do, reducing installation, O&M and decommissioning costs [37].

Once at the site, three or six catenary mooring lines are used to prevent the platform from drifting, which is the cheapest and most simple mooring system [37]. The platform is not sensitive to water depth, allowing it to be installed in a wide range of locations, this will however have an impact on the mooring line costs since this is directly linked to water depth. Catenary mooring lines use a combination of their own weight and a large footprint on the sea bed to keep the platform stable and in its desired location [14]. One main advantage of a catenary mooring system is the forces acting on the anchors are horizontal allowing cheaper anchors to be used and a greater range of seabed and water depths explored [14]. This mooring system does pose the issue of larger oscillations when exposed to waves, creating an issue for turbine operation and the export cable [32,37].

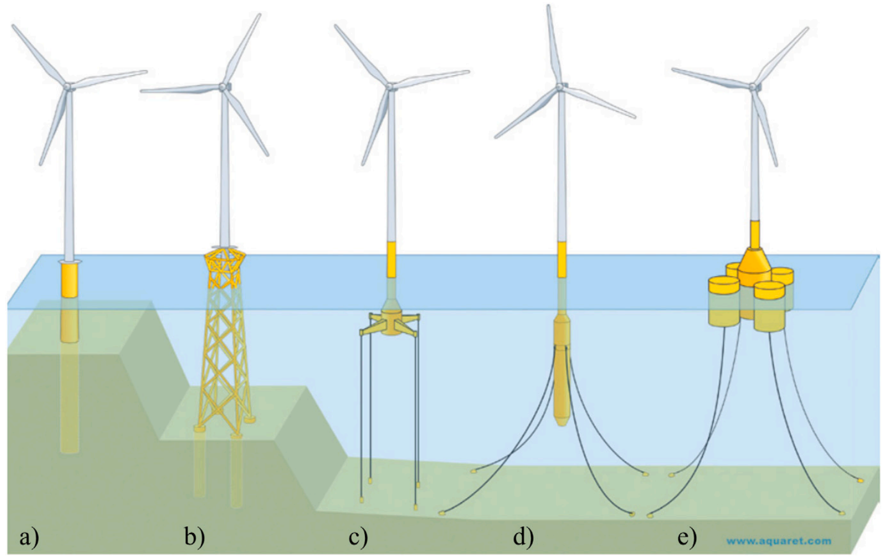

Fig. 4. Main platform types from the left: (a) Monopile, (b) Jacket, (c) TLP, (d) SPAR, (e) Semi-submersible [32].

The SPAR typology consists of a longer slender cylindrical body constructed from steel or concrete, typically utilising a catenary mooring system, similar to a semi-submersible. Unlike the semi-submersible, the SPAR has a very small water plane area (WPA) and relies on the vertical distance between the centre of gravity and the centre of buoyancy for stability. This works by the combination of the buoyancy force acting on the centre of buoyancy and the weight force acting on the centre of gravity forming a restoring moment which counteracts the inclining moment acting on the platform [32,37]. The small WPA makes the support structure suitable to operate in high sea states [37]. As previously mentioned, it has been proven feasible in the O&G industry and has been installed in depths up to 2000 m [32]. This has many advantages, particularly in locations where there is a small continental shelf close to shore. The shelf region can use traditional methods or potentially TLPs and semi-submersibles but the SPAR will allow such areas outwith the shelf to be utilised for offshore wind energy. It does have limitations, it is suggested that this configuration cannot be installed in a water depth below 130 m (for 5 MW turbines), as wind turbines become larger it is expected the SPAR size will also have to increase, increasing the minimum water depth it can be installed in. However, it can be noted that Hywind Scotland Pilot Park installed five 6 MW turbines in water depths ranging from 90–120 m. This demonstrates there is clearly a constraint on depth but maybe not as strict as the literature suggests. The deep draft also requires it to be towed in a horizontal manner, requiring a specialised vessel to position the SPAR at its site and install the tower and the Rotor Nacelle Assembly (RNA), increasing installation costs. However, due to the lack of complexity of the structure, the structural and maintenance costs should be less [32,37].

A Tension Leg Platform has large buoyancy which is restrained by a taut mooring system. The mooring system is slightly different from the catenary arrangement, where the mooring lines are essentially equal to the water depth, holding the platform in position and creating a restoring moment when inclined [32,37]. For such systems anchors which can bare vertical and horizontal loading are required, this is inherently more expensive, and the overall mooring system is more complex with higher loading. Since specialised anchors are required for this platform the design is then limited to certain seabeds [14]. The taut mooring system is more expensive, but it is more stable, resulting in very low motions, which is seen positively by RNA manufacturers. Compared to the catenary system, the footprint is smaller, requiring a lot less mooring line length and consideration for other platforms' mooring lines. Due to the high loading on the tendons, they are at higher risk of breaking and the anchors are at higher risk of becoming dislodged, therefore the system requires a higher redundancy. In locations where there is a higher probability for storm surges or large tidal variations, currently, this platform is inappropriate due to risks of overloading the mooring system, which could cause drifting and potential capsizing. TLP's can be installed in intermediate water depths making them relatively flexible [37]. Since the stability of the TLP is provided by the mooring system during the installation process specialised vessels are required [32]. There are also additional requirements for specialised vessels to install the mooring system due to its complexity. These platforms typically have a smaller draught than a SPAR but larger than a semi-submersible. Manufacturing difficulty also lies between a SPAR and a semi-submersible, with a small, simple structure comprised of a central column and a number of 'arms'.

It is evident that there is no clear consensus on which platform is the best, however, it is very likely that there will be no 'winner' as they are all good for different sites and operational conditions [14]. The most common concepts found within the literature and on test sites are shown below in Fig. 5.

It is clear that there is a large amount of diversity in platform configurations, most notably two of these platforms shown in Fig. 5 are being used in operational farms around Scotland. Concept three is being used at the Hywind Pilot site in Scotland, further details can be found here [39], which has been operational for the past five years and concept two was adopted more recently in 2021 at the Kincardine site off the coast of Aberdeen [40,41].

4. Cost modelling review

There has been little work done to develop cost models for floating offshore wind thus far, with only a small number of papers found in the literature. Castro et al. [18,42–46] have contributed the greatest number of papers in this research area, with six publications since 2014. These papers built upon their initial cost model presented in 2014 [42]. The authors [42] created a life-cycle model which was used over an area in the North West of Spain allowing the Life Cycle Cost System (LCS) to be determined over this space for the three different platform types. Expanding this model, in 2016, the researchers [18] added a wave energy converter, developing a cost model for renewable energy farms. In this work, only a semi-submersible platform was considered for the two proposed sites. In the same year, the authors [43] followed the same procedure as [18], however, the paper is made more concise removing a lot of equations used. Reducing the equations provides a

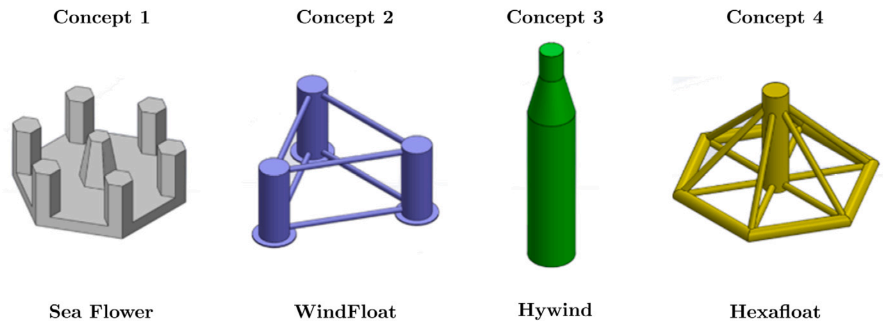

Fig. 5. Main platform concepts found in literature and test sites [38].

more general methodology, only stating the dependent variables for each section. In [44], they give a detailed cost model for the installation of three different platforms. Finally, two papers written in 2020 by Castro et al. [45,46] utilise the previously defined cost models in their work to map the LCoE, the internal rate of return (IRR), and net present value (NPV). This allows the user to determine over a selected region which platform is the cheapest and which areas in the region are cheapest. Considerations for bathymetry, distance to shore, wave height and period, and port are included in this work. The only difference between these two papers is the location considered.

Martinez et al. [47,48], in 2021 and 2022, created a map of LCoE over two different regions, for semi-submersibles which is comparable to Castro et al. [18]. Similarly to Castro et al. Maienza et al. [15] created a cost model which can be used for any platform type at a given site. In 2016 a flexible tool was created for the Life50+ project [49], which only has three inputs: water depth, turbine capacity, and distance to shore, resulting in an output of LCoE for each foundation type [50].

Mhyr et al. [51], built upon the work by [52], and created an LCoE cost model which allows both floating and fixed platforms to be compared. Bosch et al. [53] utilised some of the same methodology present in the cost models in [51,52], but is limited to Tension Leg Buoy.

Sarker et al. [54] focused on creating a model specifically for the installation cost, providing a higher level of detail than other complete cost models. Judge et al. [55] created a spreadsheet-based cost model, which includes a database of information for installation, O&M, and decommissioning to reduce the required number of inputs for the user. The most comprehensive decommissioning model within the literature is found in [56], considering both fixed and floating platforms. Although their case study focuses on a jacket foundation they highlighted the main differences in cost and how to calculate these for fixed and floating platforms. A decommissioning cost model for offshore wind was also presented by Milne et al. [57], utilising existing wind farm data, for this reason, it is suggested that this model would be most appropriate for fixed platforms given all of the data for existing wind farms is for fixed platforms.

Focusing on HVDC and HVAC transmission systems, Gil et al. [34] presented cost data for individual components and empirical formula, allowing the cost and losses of each transmission system to be compared.

Unlike all other papers reviewed, Ghigo et al. [38] presented an optimisation framework for floating offshore wind platforms with cost analysis. This work optimised the platforms geometry to minimise cost.

A simplistic cost model based on material mass was used in [58], to compare the three main platform typologies. Similarly, Heidari et al. [59] created a basic cost model, with most of the data based on GBP/MW values or trends within the wind industry. Comparable in simplicity, a number of models have been created basing all costs on a GBP/MW value [20,60–62].

A general overview of the literature in this area highlights a large amount of variation from cost model to cost model. In order to get a better understanding of the differences in each model, the following sections will break down the overall cost into five main categories, for more detailed analysis: preliminary works, manufacturing, installation, operations and maintenance, and decommissioning. Nearly every paper examined considered a similar breakdown in cost percentage with CAPEX 70%, OPEX 20%–30% and DECEX 5% [15]. This breakdown can be seen in Fig. 6, where the circled numbers highlight the number of related costs to this topic.

4.1. Preliminary works

The most simplistic way to model the full CAPEX of an offshore wind turbine is using a GBP/MW value found within the literature or from published wind farm data, an example of this approach is shown in [62]. The issue with this approach for floating offshore wind is the lack of data, the large number of potential support structures and site variation.

Maienza et al. [15] created one of the best models within the literature with a high level of detail for a 5 MW wind turbine. However, the model does lack the inclusion of costs related to concept definition, engineering, and project management. Similarly, Judge et al. [55] also neglected this cost. Generally, preliminary costs make up for around 4% of the total cost [61]. Ensuring that appropriate preliminary work is carried out is essential to ensure the project runs smoothly, and no other incurring costs are encountered at a later stage.

In [18,20,42,59–61] the preliminary cost such as market study, legislative factors, farm design, management and engineering were included. These costs are the same for all three platform typologies and are calculated based on the wind farm power capacity. Rather than using the wind farm capacity, another method which has been used is a percentage of the CAPEX, as in Lerch et al. [17]. A number of papers used data from fixed offshore wind farms, including environmental, met station and seabed station surveys, project management and development services GBP/MW values [47,48,51]. The reason fixed wind farm site data is used is because there is no real data for floating platforms as of yet, due to the lack of operational sites. The cost models presented in [51,52] have similar categories to those listed above but also include GBP/MW values for human impact studies and insurance and contingency. A general GBP/MW value was used in Bosch et al. [53] for general preliminary works, with no detail of what is included.

An improvement on a GBP/MW estimate would be to include cost information on the surveys carried out. It would be relatively simple to implement, considering installation cost models already including a variety of vessels and their related costs [15,18,44]. It is estimated by [51] that survey costs account for around 34% of the developmental cost phase.

A mind map detailing all costs which should be included in an offshore wind farm according to the literature can be seen in Fig. 7.

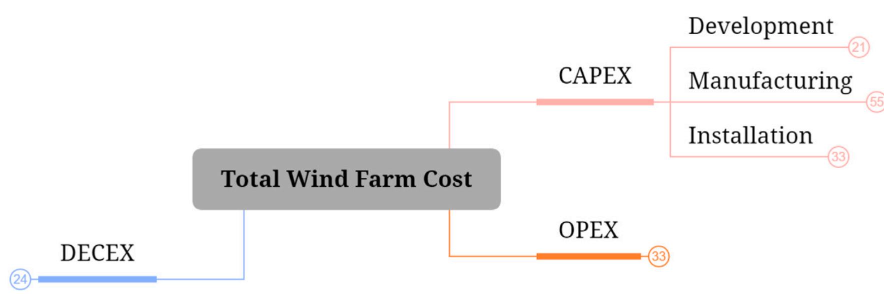

Fig. 6. Cost category breakdown.

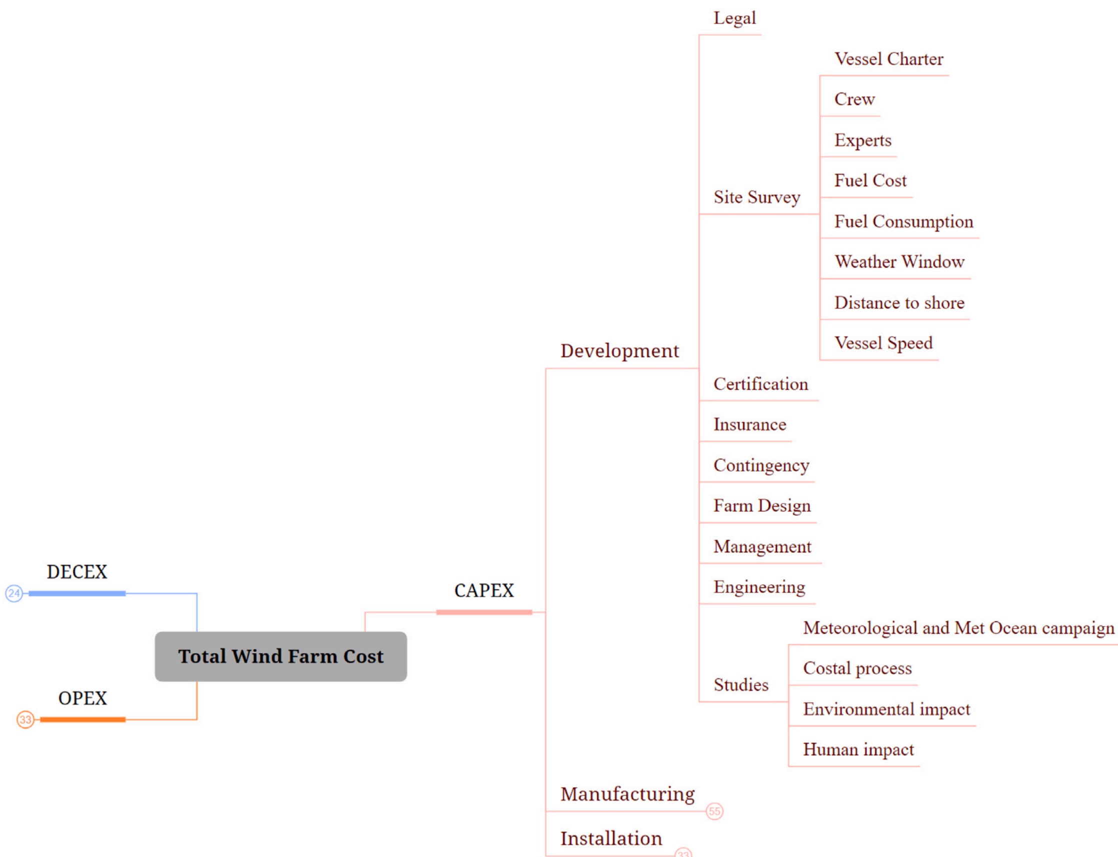

Fig. 7. Complete cost details for the development cost.

4.2. Manufacturing

4.2.1. Wind turbine cost

Generally, the manufacturing costs calculated are broken down into four main categories in a range of different research papers: wind turbines, platforms, transmission systems, and mooring and anchors [15,17,18,38,42,45,46,51,52,59]. Wind turbine costs have previously been estimated using a linear regression approach, fitting a line to 2–10 MW wind turbine cost information from a data set [15]. The most common approach to find the wind turbine cost was to use a GBP/MW value [17,18,38,42,47,48,53,59]. In [51,52], the authors used a set value for the 5 MW NREL wind turbine based on the available literature. Gil et al. [34] considered that there is variation in the cost of wind turbines, depending on whether they use HVAC or HVDC. The AC turbine cost was calculated using a formula related to wind turbine power, while the DC turbine cost was calculated as a percentage of the AC turbine because it does not require a back-to-back power converter.

4.2.2. Platform cost

Few basic cost models available used a generic GBP/MW value to cover all floating platform types [20,59–61]. Similarly, Martinez et al. [47,48] assumed a cost per platform of 8 Million Euros, because their work utilises the WindFloat platform. A simplistic method utilising linear regression to derive a line of best fit from available data, to find the platform cost considering water depth, is presented in [53]. Ioannou (2020) et al. [58] calculated different platform costs based on material mass, and a complexity factor, which accounts for the fabrication process and complexity of each support structure.

Such models can create a good benchmark value, however, it is important to consider platform variation and more detailed cost estimates, particularly as wind farm owners proceed further into the project design. Platform cost was expressed simply as material cost in terms of steel, concrete, and ballast used for the different platforms in [38]. Their research does not include additional costs related to the fabrication of the platform. Maienza et al. [15] produced a fair estimate of the floating platform cost, detailing its dependency on platform type. They calculated the platform cost including material cost based on the platform mass, painting, corrosion protection, salaries, and engineering equipment. The latter is taken as 5% of the sum of the other manufacturing costs. Castro (2014) et al. [42] found the cost for the same categories however, the relationship and any level of detail between these terms were excluded, therefore it is unsure how the above was calculated. A more detailed explanation was provided in. [18] on how these costs are found. The cost is related to the generator cost which is a function of material, direct labour, and activity cost. These costs are all a function of the platform mass, live, dead and interior surface of the platform, cost per hour, and the cost of steel. It is unknown what the live and dead surfaces are of the platform since the author does not explain this. In Lerch et al. [17] the substructure cost considered material, labour, overheads, shipyard hire and transport to port. Myhr et al. and Bjerkseter et al. [51,52] found the cost of the material consumed based on a GBP/kg and the manufacturing cost, including: rolling, cutting, painting, corrosion treatment of steel plates, welding and miscellaneous assembly of materials into complete structures. This is accounted for based on the complexity of the platform, which changes with different concepts [51,52].

4.2.3. Transmission system cost

Ghigo et al. and Lerch et al. [17,38] used a simple, yet effective way to find cable cost using the price per meter of array and export cable. The transmission system in [15,42] defines export and array cable costs for the given distance and water depth, considering the voltage rating and whether high voltage AC (HVAC) or DC (HVDC) is used. There is a general rule that around 50 km offshore, HVAC becomes more expensive, so switching to HVDC is more cost-effective due to lower losses [34]. Bosch et al. [53] considered the HVAC and HVDC possibility drawing upon the literature to give a set value for the transmission cost with a power of 500–1000 MW. In 2016, Castro et al. [18] decided to remove the inclusion of the HVDC link, probably due to the site selected for the case study being relatively close to shore. A general cable cost was found using the water depth, distance to shore, and relative distance from the platform to the substation. The found length is then multiplied by GBP/m of cable [18]. This work did not include the difference in cost for export and array cables, which is an oversimplification. A less complex approach was considered in [47,48], neglecting the variation of voltage rating. The transmission system in [51,52] included export and array cables, considering GBP/m, with additional thought for the cable diameter and voltage. Similar to the other papers listed, in this research, only HVDC is considered.

The most detailed transmission cost for HVDC is presented in Gil et al. [34]. This work presented four different collection grids, highlighting the parallel HVDC configuration to be the most comparable to the traditional radial layout used for HVAC. Rather than using the GBP/m value to find the cost of cables, authors implemented two different formulae for both AC and DC cables which consider: length, current, and coefficients related to voltage rating. Unlike the majority of papers, [34,43] included the cost for transformers, but both studies use different methods. Gil et al. [34] used a formula related to rated power and Castro (2016) et al. [43] used a set value. Other components considered in [34] are AC/DC & DC/DC power converters and switchgear. The cost relative to the AC/DC converter is derived as a function of the rated power, while the DC/DC is a set value depending on the layout and power capacity of the farm. Switchgear costs were modelled as a function of the nominal voltage. Platform (substation) costs vary rapidly depending on whether AC or DC is used. To represent this cost, Gil et al. [34] used a simplistic formula for the AC platform, and a more complex formula for the DC case, including feeder and collector platforms.

In [15], the offshore platform for the electrical station cost was expressed as 11% of the installed power. Using the wind farm power in MW and providing the cost in millions of Euros. The onshore platform was expressed as half of the price of the offshore platform. Both platforms necessary for energy transmission, onshore and offshore, are considered as a fixed value in [51,52]. Research by the following [47,48] uses a fixed value for onshore and offshore transmission platforms, considering the number of each platform required, depending on whether HVAC or DC was used. Lerch et al. [17] decided to exclude the cost of an onshore substation because it was assumed that there should already be one existing. The offshore substation considers the number of transformers used [17]. Ghigo et al. [38] represented both onshore and offshore platforms with a set price. Heidari et al. [59] used data from existing wind farms in order to fit a linear function dependent on distance to shore to find the total cost of the transmission system.

4.2.4. Mooring and anchors cost

The station keeping costs were expressed in [15,17], considering the different platform types and the requirement of different material types for each mooring line configuration. Maienza et al. [15] used a GBP/kg estimate for the anchors. It is fairly straightforward to find the cost of different anchor types for each configuration, however, two set values were used here for catenary and taut mooring. Compared to [42], this work considered wind, wave, and current forces in order to determine the required mass of the mooring line and anchor, where similar to [15] the cost was calculated in terms of GBP/kg. [59] used a similar approach considering the minimum breaking load of the mooring line within empirical formulae to find the cost for both mooring and anchors. An additional consideration by [42] was the use of a chain in waters less than 40 m and synthetic rope for deeper waters. [18] calculated mooring and anchors based on a GBP/m and GBP/kg value respectively, neglecting different mooring line types. Lerch et al. [17] found the cost of anchors in terms of the number of anchors. Martinez et al. [47,48] utilised a formula to determine the cost of the mooring system, considering the number of anchors, length of mooring lines and chain, the cost of each, and the water depth at the selected site. A range of different anchor and mooring line types are considered in [51,52]. This allows different platforms to have a more accurate cost as some require different mooring configurations. The cost is represented as the price per anchor and price per meter of mooring line. Mooring line types considered are chain, wire, fibre rope, and pipe. The stiffness of the mooring line and the appropriate diameter is also selected for the upper and lower section of the line to ensure it does not exceed the minimum breaking load. The most simplistic account for mooring and anchors cost is presented in [38] using a set value for each, not considering water depth, or different requirements for different platforms. All of these subsystem costs are considered as ‘dry CAPEX’ in [55], where details of how each is calculated have not been provided.

Notably, Lerch et al. [17] were the only researchers to include transportation costs within the manufacturing stage, considering parts and materials have the requirement to be moved from a different site to the port. Such costs include offshore costs, vessel hire, number of vessels, fuel rate, fuel cost, and time required to perform a task, as well as port costs including equipment hire (cranes), number of equipment used, time for the task, and storage hire [17]. Fig. 8 shows all of the costs related to the manufacturing costs.

4.3. Installation

Maienza et al. [15] developed an installation model discussing a range of different vessels within the text, it has however been noted that for the calculation of time to transport from port to farm, only two vessel speeds are available: tug and crane speed. Similarly, [18,42] also considered the use of different vessels for installation. An issue surrounding the installation is the lack of clarity on the vessel charter type in all papers expressed within this review. This is an important factor to consider as this determines whether the client must provide their own crew and pay fuel costs. [15,18,42] did not explicitly state if such costs are included within the hire rate. It is important to account for fuel costs due to its volatility and since there are limitations on which

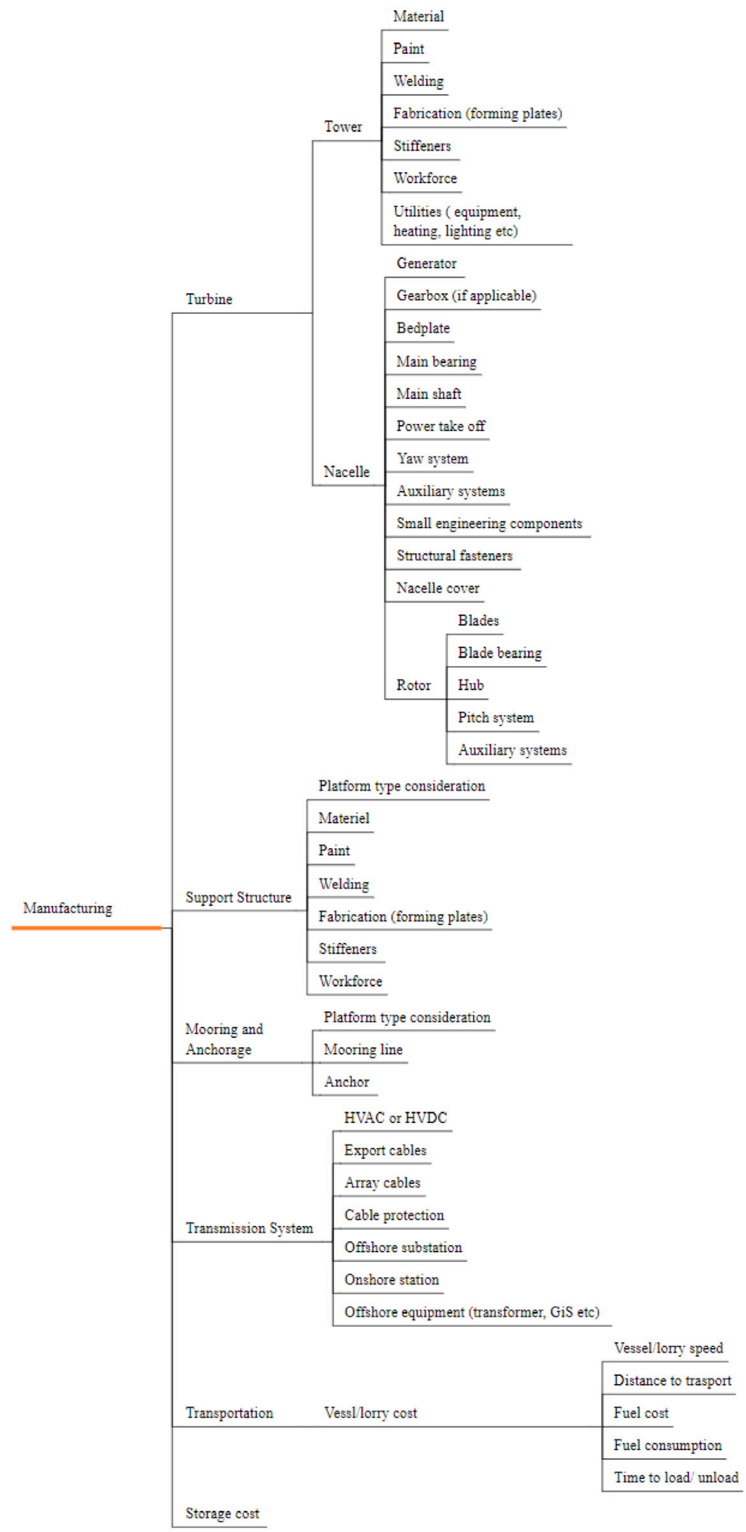

Fig. 8. All costs related to the manufacturing cost.

fuels can be used due to the sulphur cap in place, pushing consumers to use more expensive marine diesel oil compared to traditional heavy fuel oil [63]. Work by Lerch et al. [17] did not state the charter type but it does include fuel cost and fuel consumption. It is however unclear if this is fixed or varied for each vessel type.

In the following work [15,17,18,42] the installation cost was broken down into turbine, platform, mooring, anchors, and transmission systems. This captures all of the turbines' major systems. A range of different installation methods has been well explained within [15,17], highlighting that a single lift is generally the best for a floating platform. The installation was however varied to suit each platform making it more accurate. Work carried out by Castro (2018) et al. [44] focused purely on the installation cost, similarly to [15,17], this research included six potential lifting methods. Consideration of the shipyard capabilities is also considered in [15,44], related parameters were given in the latter, these parameters are: storage area and shipyard draft.

When the shipyard is insufficient, the closest port was utilised also considering the transportation cost from port to yard [44]. Castro (2018) et al. [44] considered different methods for installation of each system, i.e mooring and anchors installed via a tug and barge or specialised anchor handling vessel, and a similar procedure is carried out for the other systems. This research is probably the most detailed account of installation costs, with the inclusion of a very high level of detail including vessel type, speed, range of installation methods for each system, range of lifting methods, time to carry out all tasks and comprehensive equations and tables of data used within the calculation. However, similar to all other papers, there is no charter type, fuel cost, or fuel consumption of any vessel included. On top of this, there is no account of crew or technicians, without which no work would be carried out.

The cost model within [59] included the installation of SPAR and Semi-submersible utilising an empirical formula depending on the distance to shore and port cost only. Another method which utilised a formula for turbine installation is [47,48], this cost depended on vessel hire, speed, number of turbines, turbine capacity of the vessel, and installation speed. This model did, however, only consider a jack-up crane as the vessel used, limiting the installation site to a water depth of about 50–60 m as this is the maximum operational range of such vessel [47,48].

Myhr et al. [51] calculated the installation cost of the turbine and platform considering a range of methods, allowing the cheapest for each platform to be highlighted. This model considered the requirement for different vessels but does not explicitly state if it is considered within the cost model. Similarly, the only time considered is that of the installation at the site. It does not include travelling to and from the site, or the number of crew/technicians to do such tasks. Installing the cables was based on a GBP/m value, and station keeping installation cost is based on deck capacity to store the system, transition time, installation time, and operational window to carry out the installation [51,52].

Relatively simple models for installation costs were included in [20,60,61], using a GBP/MW value for all installations, with no variation for different platforms or distance to shore. Similarly, Bosch takes information from [51,52] and considers the installation cost to be GBP/MW, they did however consider the platform type [53]. Ghigo et al. [38] also considered a GBP/MW value for the Hexafloat and SPAR platforms.

Sarker et al. [54] sought to minimise the cost of installation and hence reduce the LCoE. The installation process highlighted the use of a jack-up vessel, which is not appropriate for substantial water depths, hence is not deemed applicable to floating platforms. The type of platforms this installation model used is not stated, but it is expected to be suitable for fixed wind turbines only. It did, however, include a learning rate parameter, which could be useful for all areas of floating offshore wind as the number of operational sites increase, which would be helpful for all costs [54].

Judge et al. [55] includes a range of different installation techniques for the different systems, such as different methods for cables: plough burial or separated trenches, turbines can be fully assembled or partially, and the support structure can be floated out or crane lifted. The hire, fuel cost, and the number of turbines or foundations each vessel can transport with the selected installation method, transport distances from manufacturing centre to port by road and sea for all project assets (e.g. turbines, foundations, export cable etc.) as well as the distance from port to offshore site are all considered in this work. Additional project costs such as project management, port costs, and survey and monitoring costs were included in the installation phase, which in general would be in the first section of preliminary works'. A highlight of this work is the use of meta-ocean data to determine weather windows to carry out any activities offshore such as installation, O&M and decommissioning [55]. Fig. 9 shows all of the costs found in the literature related to the installation.

4.4. Operations and maintenance

O&M captured within Maienza et al. [15] included insurance and seabed rental, along with preventative and corrective maintenance. Both maintenance types include the probability failure rates of each component and the related downtime to carry out the repair. Indirect costs such as port storage, vessel hire, and maintenance planning were also included. One parameter which is not included is availability, which is a considerable factor which can affect the length of downtime and therefore revenue. This is however not a simple task to include and would require a model in itself [15].

The operational cost found in [18,42] included tax, assurance and management costs, all related to the GBP/MW value. Maintenance costs are also included considering the failure rates of components. One main difference between [42] and [18] is the assumption made in [42] that all maintenance is carried out via a helicopter. This is a very specific assumption, based on a number of different works, it has been stated that helicopters can only operate below 1.4 m significant wave height and 18 m/s wind speed [64], heavily limiting the availability and reducing flexibility.

Lerch et al. [17] opted to incur general insurance, contingency and operation costs within their model which was related to a GBP/MW value. The maintenance, similarly to the previously explained paper is split into corrective and predictive maintenance. The latter depends on the frequency of maintenance, vessel hire, fuel cost, fuel consumption, materials needed, and cost of divers [17]. Cost related to 'divers' includes all personnel costs and time. Corrective maintenance follows a very similar calculation, but it also includes annual failure rates for each component [17].

[51,52] utilised a preexisting cost model for O&M called OMCE-Calculator. This is generic and does not use wind farm data, it is based on past experience and engineering judgement. Unplanned, condition and calendar-based maintenance is considered for floating and fixed, detailing the number of maintenance events for each. Downtime, time to repair, number of crew, vessel hire, port fees, inspections each year, and spare parts are all considered in this work [51,52]. Alongside the maintenance insurance costs were also considered GBP/MW. One main parameter which has been neglected is the distance to shore, hence there is no consideration of the additional time to hire the vessels to get to the site. It is however expressed that the maintenance strategy will have a mother-ship at the wind farm site, with daughter crafts to carry out any work. These vessels will still have to come to the port to change, crew, refuel etc, which is neglected. Fuel costs are also not considered for any vessel [51,52]. [53] re-used the methodology laid out in [51,52]. Judge et al. [55] similar to other models, their research included preventive, corrective, and condition-based maintenance. There are no formulas to highlight relationships or how costs are found, but the main parameters were: vessel hire, type, personnel, spare parts, time to complete a task, vessel mobilisation, downtime and most importantly weather windows to carry out the O&M [55].

A simplified assumption for the O&M cost was presented in [20,38,60–62] based only on GBP/MW. A slight improvement on using a GBP/MW value is to consider the distance [47,48], used data from other research, and modify the GBP/MW value to consider the distance to shore for their own site. Similar to installation cost the O&M model within Heirdari et al. [59] only considered distance to shore and insurance (GBP/MW). The most simplified assumption seen for both O&M and decommissioning was presented by Ioannou (2020) et al. [20] neglecting both costs because they are assumed similar for each platform. Mhyr and Bjerkseter et al. [51,52] also considered O&M to be the same for each platform. Based on all other literature which analyses the three different platforms stated above, this is not true. A mind map is presented in Fig. 10 highlighting all costs related to the Operations and Maintenance of a wind farm.

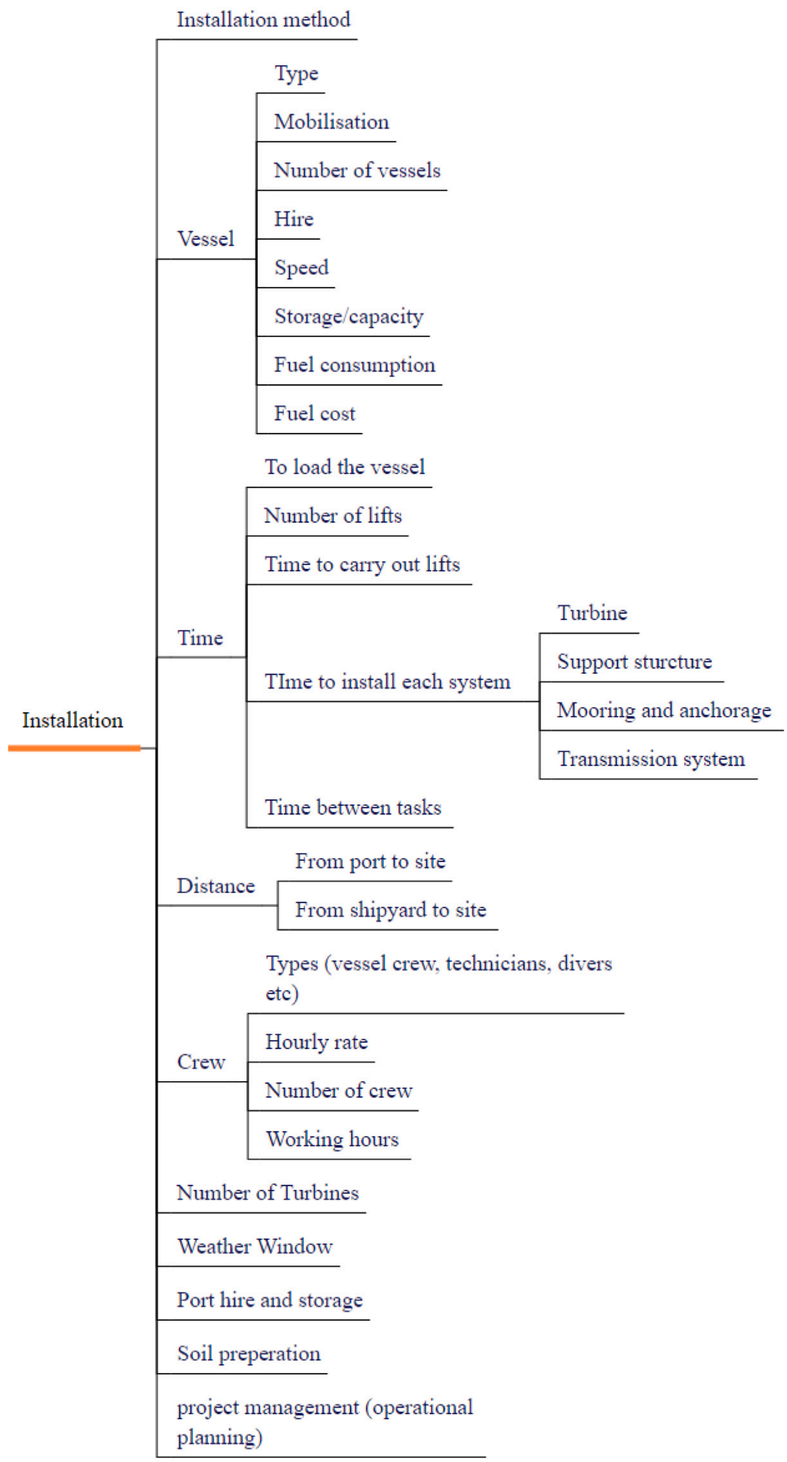

Fig. 9. All costs related to the installation cost.

4.5. Decommissioning

In [15,38,53], the decommissioning costs were expressed as a percentage of the installation cost, which leads the author to determine that any uncertainty is carried over from the installation cost to the decommissioning cost. Maienza et al. [15] also included the cost related to site clearance represented as a cost per area. Castro (2014) et al. [42] had a slightly more comprehensive decommissioning cost, including distance to port and shipyard, vessels required, hire rate, and vessel speed. This model also included the reselling of scrap metal, which brings down the overall decommissioning cost. Castro (2016) et al. [18] employed the same method as their previous work but presented more detailed formulae. A more in-depth model was presented in [17], where the decommissioning cost was split into main subsystems, and for each subsystem, the disassembly cost, transport, and port fees are calculated. The first two considered vessel hire, number of vessels, crew, and the time this takes to be completed. The port fees were related to the cost of hire, storage space, and the use of vehicles. Site clearance was

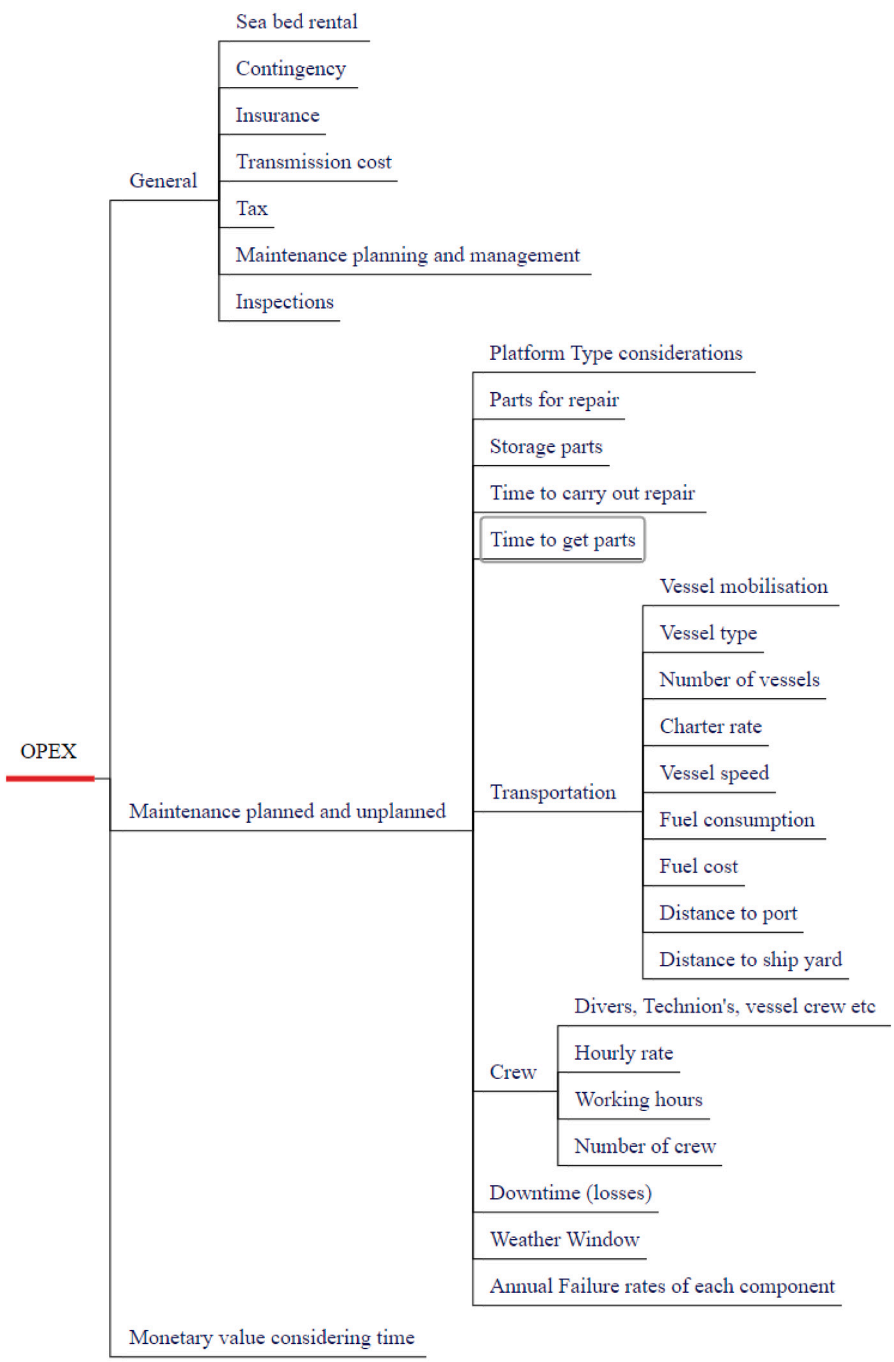

Fig. 10. All costs related to the Operations and Maintenance cost.

also considered to ensure the wind farm site is restored to its original state, this cost was based on the area. Finally, disposal and selling of all materials, including material cost and transportation costs, were included [17].

An opposing opinion on most papers is that of [59]: this work considered the DECEX to be negligible because they expected scrap costs will cover any removal and clearance costs. In [47,48] it was assumed that the decommissioning of a wind farm will only create revenue due to the scrap material, considering a return of 250 kEuro per MW. This paper highlights the large amount of uncertainty when predicting this cost, due to uncertainties about the time that decommissioning activities are anticipated to take place, the duration of the decommissioning process, the weather window for execution, options available for decommissioning, etc. Another factor not considered in [47,48], but considered in [51,52], is the fluctuation in the price of steel for scrap cost.

Adedipe et al. [56] broke the DECEX into four main categories: planning and regulatory approval, execution, logistics and waste management, and post-decommissioning. This is the only work to have considered regulatory approval, currently, it is not necessary for wind farms, however, it could be in the future, hence the cost was based on approval needed for oil and gas projects. Engineering and management costs, contingency, and insurance were considered within this subcategory as a percentage of total decommissioning. [55] is the only other paper to have considered these costs within the DECEX model. The execution phases within both [55,56] included: disconnection of wind turbines from the grid, cost of wind turbine preparation for removal, cost of lifting and removal of wind turbines, tower, foundations and scour protection, cost of decommissioning of offshore substations, and cost of decommissioning of all cables. Within each section, considerations for the time to carry out all tasks, vessel hire, type of vessels, number of vessels, crew costs, distance to port and number of journeys required [56]. The cost related to logistics which considers how the decommissioning will take place and the organisation of transport and recycling/scrapping is calculated in [56] and includes the same parameters as the execution phase which was previously described. Both Judge et al. [55] and Adedipe et al. [56] include waste management costs, detailing: port fees, landfill cost, salvageable materials, waste processing for non-recyclables, transportation costs to the landfill/recycling centre, capacity, number of trips, and how far the truck needs to drive [55,56]. The post-decommissioning cost in [55,56] includes: site survey, site clearance, site monitoring, site remediation, and miscellaneous costs, but the details on the calculation are not given. The main difference between [55,56] is the level of detail presented. Judge et al. [55] did not include any formulations on how the cost is calculated, unlike Adedipe et al. [56].

In [51,52] the decommissioning costs were expressed in GBP/MW with the scrap cost in terms of mass highlighting that some platforms actually create revenue from decommissioning. Stehly et al. [60] excluded decommissioning costs, but included a decommissioning bond: this is a financial agreement to ensure proper removal and site clearance. In the Refs. [20,61,62] decommissioning cost was not considered.

Everything related to the decommissioning cost can be seen in Fig. 11.

4.6. General assumptions

The approaches presented in [15,42,53,59] used a formula to calculate LCoE that did not contain a discount rate, but this is important to include as over time the value of money varies, particularly when it is over a wind turbine life (20–25 years). Castro (2014) et al. [42] had what seems to be a quite comprehensive cost model, however, it does not state any formulas used to find the end results. Then in 2016, the authors [18] provided more details on the formulations used, although it is both for wave energy converters and offshore wind turbines. The work which considers the discount rate in the LCoE calculation are [17,18,20,38,45–48,51–53,59,60,62]. The following authors also decided to separate the cost into CAPEX, OPEX, and DECEX because the only values which should be exposed to a discount rate are OPEX and DECEX, since CAPEX is typically paid at the start of the project [18,38,45–48,50]. Duan et al. [62] considered a discount rate for both CAPEX and OPEX, where CAPEX is spread over the first four years of the project and OPEX does not get considered until after the first four years of operation.

A common method to find the Annual Energy Production (AEP) is the use of the Weibull probability density function (PDF) shown in [15,18,42,51]. Castro (2016) et al. [18] however considered the efficiency of the transmission and the overall availability of the wind farm, making it more accurate. The layout of a wind farm is generally considered in a grid format within cost models. [15] ensured the wind turbines were spaced seven diameters apart, whereas [45,46] considered intra-Row and inter-Row spacing of four and seven diameters respectively. The life 50+ LCoE modelling tool was used within [17], with further details easy to find in [50]. When calculating the LCoE, [17,50] the AEP is required, unlike other papers it did not include considerations for losses. The losses were listed as turbine, wake, availability, collection and transmission losses [17]. Similarly, Heidari et al. [59] included losses in this calculation, but also considered the capacity factor. Losses such as availability, electrical, aerodynamic, and others were considered in [47,48,51,55]. Electrical losses are converted into a cost metric in [34], by considering the energy price of the given year and the losses related to the transmission system.

Another consideration made by [52,59] was the year the data used was found. Rather than using it straight from literature, which could potentially be years old, each cost value was translated with a discount rate to todays money. Table 2 highlights the assumptions made within the literature for losses and methods to find AEP. The capacity factor in some cases was assumed and in others was calculated based on the AEP calculation. The INC. abbreviation is included to show that it was considered in the work, but an explicit value was not expressed. Using a Gaussian distribution with a confidence of 95% the maximum and minimum values for each value were found.

This work covered in Section 4 is summarised in a table found in the supplementary document found in Appendix 1. This table highlights what existing research includes and does not include in their work.

5. Data review

The aim of this review is to analyse the data presented in the literature, identifying what the causes are for the large variations in cost estimates.

There is a general trend for the sites expressed in the literature, as wind farm capacity increases the distance from shore increases. This pattern can be seen in Fig. 12.

One major issue with comparing literature is the huge variation in sites used. In order to consider this in the comparison, some of the values have been made dimensionless with respect to capacity and distance to shore, removing the limitation of units, and allowing each paper to be compared in a fair and consistent manner. The preliminary concepts and manufacturing costs for the majority of the sub-system were presented in a MEuro/MW value, as these are not affected by distance or water depth. The mooring cost was presented in MEuro/m to consider the depth of each site. The installation, O&M, and DECEX costs were all presented in MEuro/MW/km to remove the power and distance to the shore element.

5.1. Capital expenditure

5.1.1. Generic costs

This section includes preliminary, turbine, and transmission system cost estimates found within the literature, see Fig. 13.

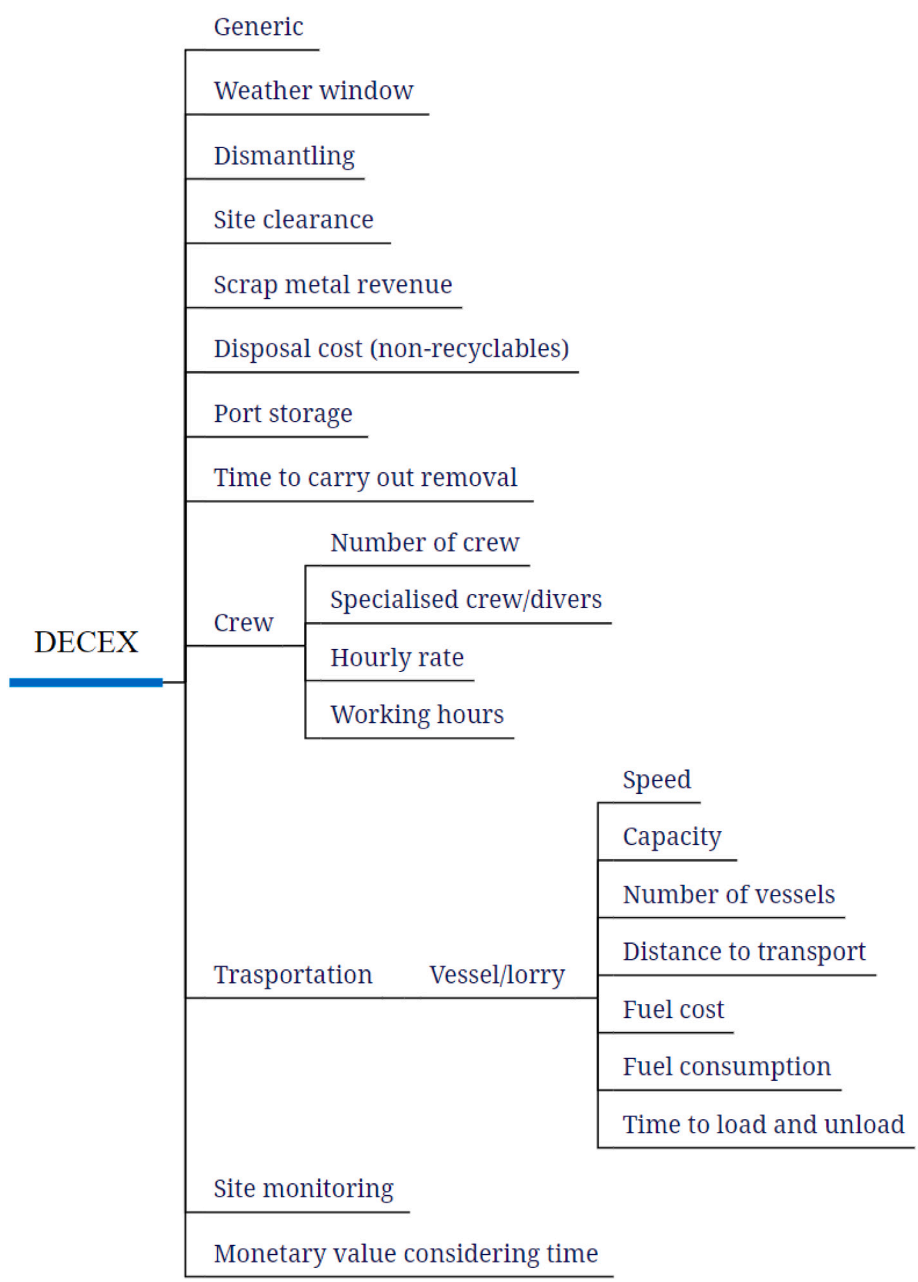

Fig. 11. All costs related to the decommissioning of the wind farm.

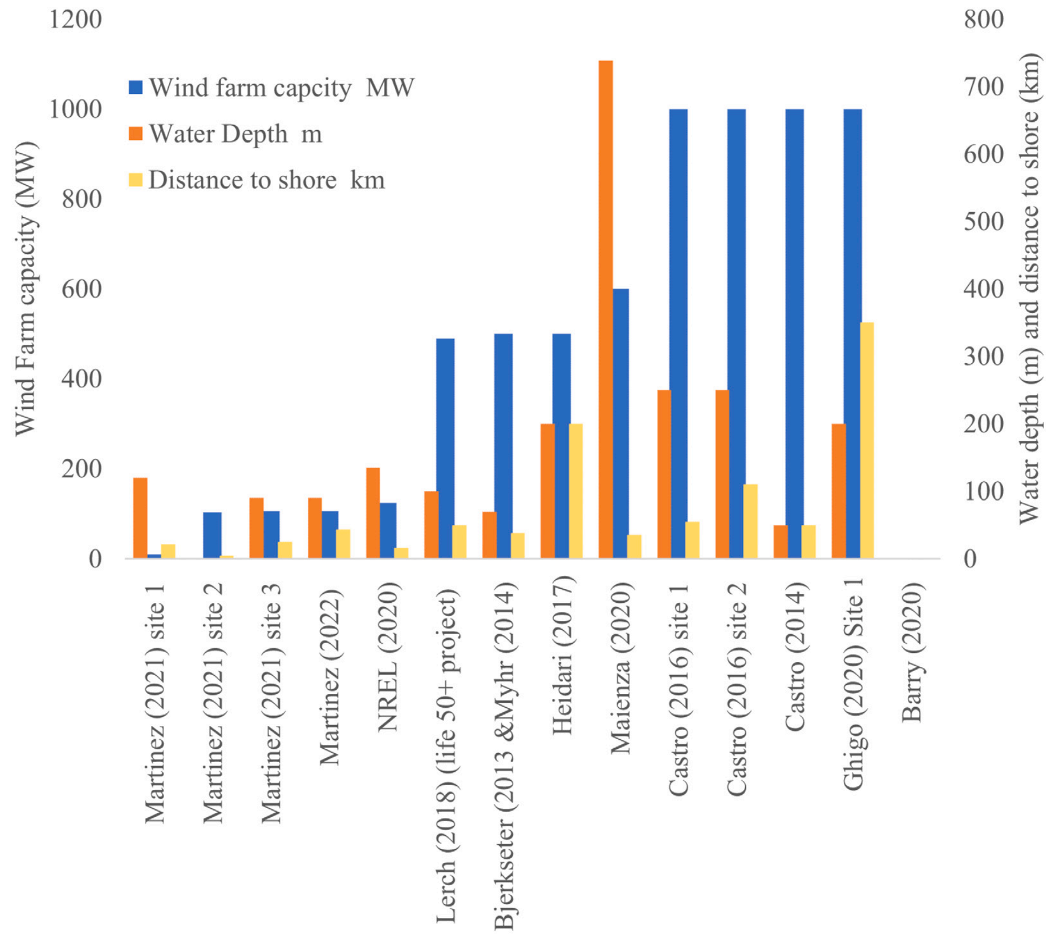

Fig. 12. Varying wind farm capacity, water depth and distance to shore for the literature.

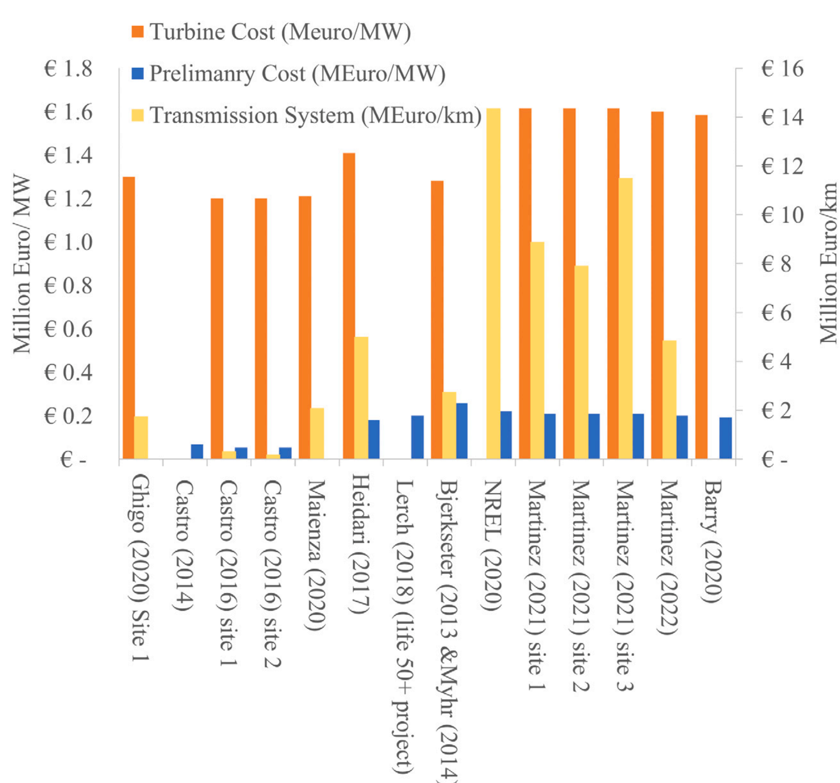

Fig. 13. Preliminary costs, turbine and transmission costs found within literature represented in MEuro/MW.

Table 2
Losses and methods to find AEP as reported in the literature, INC. means it is included but no explicit value was stated.

Reference	Capacity factor (%)	Electrical losses(%)	Aerodynamic/ wake losses (%)	Other losses (%)	Availability (%)	Discount rate (%)	AEP method
[15]			5.26				Weibull
[18]		INC.			INC.	INC.	Weibull
[46]						8	Weibull
[45]						INC.	Weibull
[17]	Calculated	INC.	INC.		INC.	INC.	Weibull
[59]	42	1	7	3	95	9	Capacity factor
[60]	38				98	5.8	Weibull
[20]	52.1	1	9	4.6	95.4	8.9	N/A
[62]	INC.					INC.	Capacity factor
[47,48]	Calculated.	1.8	7	3	94	10	Weibull
[51,52]	Calculated.	1.8	7	3	93.8	INC.	Weibull
[53]	Calculated.	3	INC.		97	INC.	Probability method
[38]	Calculated.	3.6	10			INC.	Weibull
Average	44.03	2.03	7.54	3.4	95.53	8.43	
Maximum	56.28	2.91	8.93	4.34	96.9	10.57	
Minimum	31.78	1.16	6.15	2.46	94.16	6.28	

The Euro/MW value for both preliminary and turbine costs is relatively similar for each paper, which is to be expected considering that these costs should not vary with parameters such as water depth or distance to shore.

The transmission cost, on the other hand, is generally increasing with the distance to shore, which makes sense as the cable length is increasing. The expected trend was taken from Maienza et al. [15] since this work has a very detailed cost model for transmission cost including all details relevant, hence this was used as a rough guide when looking at the trend in literature.

Castro et al. [18] has an extremely small value for transmission cost. However, the cost model is relatively detailed considering both water depth and distance to shore in the cable cost calculation. The expected reason is the lower installed power compared to other sites, and this is shown in Fig. 13 which highlights that overall, other sites have a capacity five to ten times greater.

Myhr et al. [51] and Bjerkseter et al. [52] present a relatively low value, this is potentially due to only including a Euro/km value for cable cost. This is a set value for both export and array cables, therefore it is assumed the export cable cost has been underestimated. Both onshore and offshore substations were considered fixed costs. Ghigo et al. [38] has a lower value than expected, but this research does not include HVDC, which would explain the lower cost estimate since HVAC is cheaper than HVDC. This model only uses set values for the on and offshore substations, these costs in other literature have been shown to vary with wind farm capacity.

Stehly et al. [60] utilises a Euro/MW value, Heidari et al. [59] also express the transmission cost in the same way. Both completely disregard the length of the cable and the water depth at the site. This is expected to be the reason for the substantial overestimation in [60].

Martinez et al. [47,48] show a decreasing trend with increasing distance to shore, which in general may be considered as inaccurate as generally the distance to the shore is increasing along with the water depth. The method used to calculate this cost is based on the length of the cable required and hence the distance. This cannot even be considered as a benefit from increased wind farm capacity because each site presented in [47,48] has the same wind farm capacity. The break-even for HVDC technology is 72 km, hence it would be expected that Martinez et al. [47] site three would be cheaper than sites one and two. Since site one is 5 km further offshore than site three and site two, it would be considered for HVDC technology.

5.1.2. Manufacturing costs

Platform manufacturing costs can be seen in Fig. 14. It can be highlighted that there is not a strong trend present. This could be potentially due to the different configurations of the three main platform typologies. With this in mind, it would be expected that the SPAR would have a slightly similar value for each piece of research, given it has a relatively standard geometry. Comparing the literature it can be seen that the MEuro/MW value is decreasing with installed capacity, with TLPs following a similar trend. This could be due to the benefit of a higher amount of power produced or potential cost reductions due to mass production. On the other hand, semi-submersible costs appear to be relatively similar with some outliers. A potential reason for more consistency is the higher amount of research done on the platform.

In [51,52] the manufacturing cost is well presented, considering material cost and a complexity factor for each platform. The semi-submersible has the highest complexity factor, while the TLP has the lowest. The semi-submersible is also expected to have the highest mass, followed by the SPAR and the TLP. It is mainly for these reasons the semi-submersible is the most expensive. Considering the size of the SPAR, it would be expected that it would have a higher mass, as shown in the work by Maienza et al. [15]. The formula to find manufacturing cost in [15] relies mainly on platform mass and direct labour, explaining why the SPAR is the most expensive. This confirms the authors suspicions that the mass of the semi-submersible would potentially be a lot less than the SPAR. The semi-submersible is 293 tonnes less in [15].

Heidari et al. [59] follow a similar trend to Myhr et al. [51]. The main difference being the SPAR is expected to be more expensive than the TLP. This is reasonable when considering the mass of each platform and the generally low complexity of each. The methodology to find the platform cost in Heidari et al. [59] uses the cost per tonne of: columns, stiffened columns, truss members, heave plates, and outfitting. This considers the mass of each platform and additional components and hence the increased complexity of the semi-submersible.

[60] has a higher value than other papers, but it is hard to determine the cause since the paper does not explain what is included in the platform manufacturing cost, only a simple GBP/MW value is given. Similarly, Johnston et al. [61] considers a set Euro/MW value for all floating platforms, considering previous explanations, it is a wrong assumption. Considering it is a generic value for all platforms, it has a very similar value to [15,51,52,59] if they were averaged out as one cost for all platforms. Martinez et al. [47,48] have very average values, but this model uses a set value for the platform cost found within other literature for the WindFloat platform. This cost considers the labour cost etc. making it a good benchmark for a semi-submersible cost comparison. Ghigo et al. [38] have predicted relatively high platform costs, the model uses only the mass of the platform, explaining why the SPAR is expected to be more expensive than a TLP.

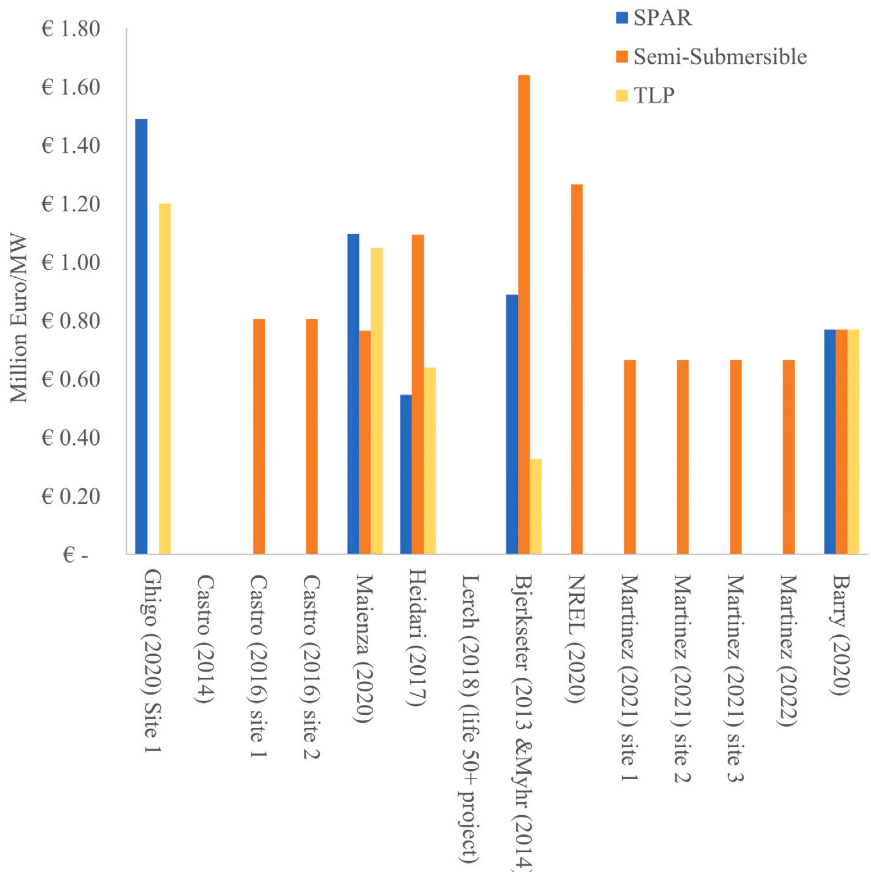

Fig. 14. Platform costs for each typology found within literature represented in Million Euro/MW.

The mooring and anchors (M&A) costs are presented in Fig. 15. M&A given Euro/m is increasing with water depth, this highlights that the deeper the water the more expensive the mooring becomes, which is in line with the fact that the footprint for the catenary system will also have to increase.

Martinez et al. [47] site three have a large Euro/m value for mooring and anchors. The reason for this is the way their model calculates this value. It considers the mooring line length is 560 m for 100 m depth and an additional 150 m of mooring line is added for every 100 m of increased water depth. Ghigo et al. [38] uses set cost for M&A with no variation depending on platform type. Considering other literature, and that there are different types of mooring configurations, this is a very simplified approach. This could explain the very low GBP/m value presented. The other papers, shown in Fig. 15, [15,18,51,52,59] all follow the expected increasing trend with water depth.

Heidari et al. [59] consider the price of M&A for the SPAR and semi-submersible to be the same, which makes sense since they both utilise catenary systems. Although TLPs have shorter mooring lines overall they are more complex, which could explain their higher cost in [51,52,59]. Maienza et al. [15] consider TLP to be the cheapest, this could be potentially due to the model using length to determine the mooring cost and fixed anchor costs. Semi-submersible was determined as more expensive than SPAR in [15,51,52], this is expected to be due to semi-submersibles having a larger waterplane area and second moment of waterplane area, leading to higher wave load. Greater wave loads cause the platform to experience greater vertical motions, and hence loading on the station keeping, requiring anchors with a higher capacity.

Combining all manufacturing costs to a Euro/MW shows an expected trend of increasing cost with distance to shore. This is due to the transmission cost increasing with distance to shore and generally the depth increasing with distance, hence mooring costs should also have a larger contribution. See Fig. 16.

The variation in the cost data is presented in Fig. 17. The maximum and minimum values presented in this work were found across the literature and are highlighted as blue and green points respectively. The average from the literature is represented as a red point and the standard deviation for each cost is provided on the graph. The greatest uncertainty lies in the transmission system cost, which is expected given some literature includes HVAC and not HVDC. Overall, the platform cost is relatively similar throughout the literature for each platform. The mooring and anchors have the least variation for the SPAR, which could be due to the Hywind site being already installed and operational for the past five years.

5.1.3. Installation costs

Overall, looking at Fig. 18, a clear decreasing trend is noted with increasing farm size and distance to shore. A few of the papers within the literature do not fit this trend, however, potential reasons for this are explained below.

Castro et al. [18,42] and Maienza et al. [15] follow a very similar trend given the sites selected for each paper. Both papers have a very detailed process, making them a few of the more accurate papers within the literature.

Stehly et al. [60] and Ghigo et al. [38] use a GBP/MW value and Heidari et al. [59] use a formula related to the distance to shore, which has been fitted to the data from other literature. Both [59,60] have slightly higher values than expected. Both methods may provide inaccurate results since they do not include vessel cost, speed, fuel cost, fuel consumption or installation methodology.

Martinez et al. [47,48] utilise a set value for the installation cost of the platform, a Euro/km value for anchor and moorings, Euro/km

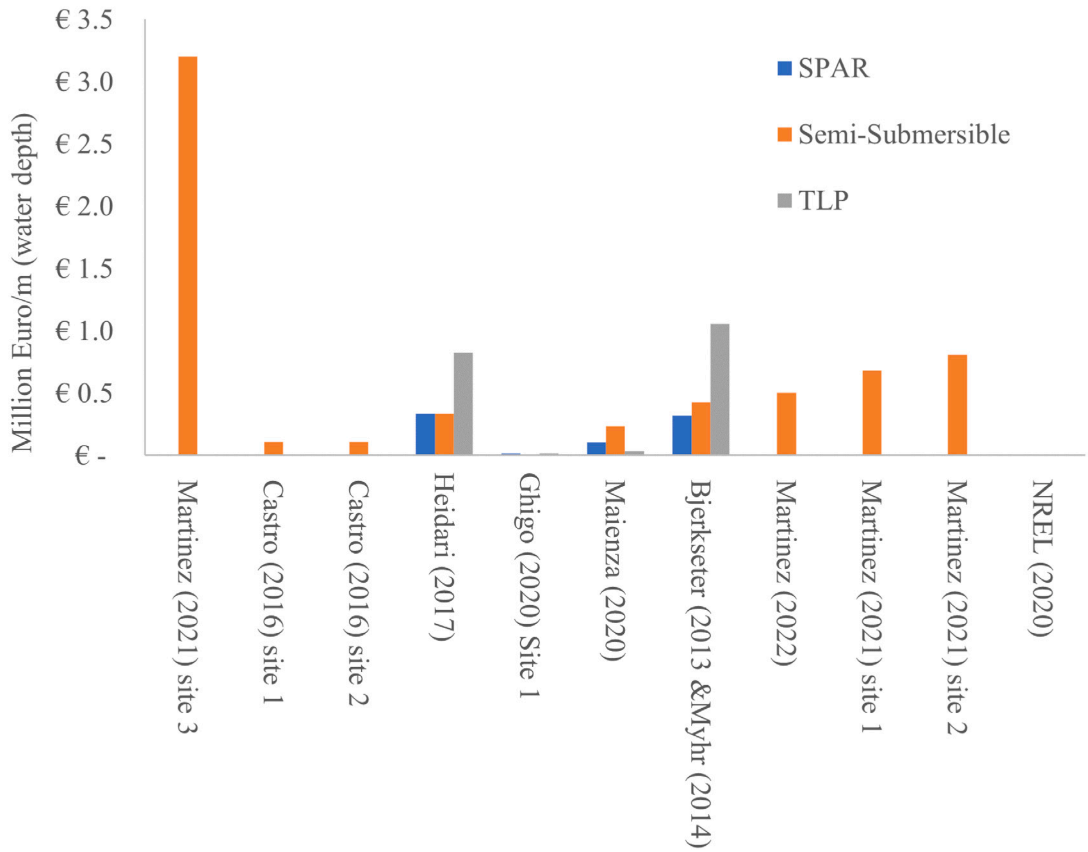

Fig. 15. Mooring and anchors costs for each typology found within literature represented in Million Euro/m (water depth).

for the transmission system, and finally a formula including time to carry out the work and vessel details. This is a simplistic method to find the installation cost. The output of these papers seems rather small when compared to other literature, causing the author to question the accuracy of the assumptions made rather than calculating vessel cost and installation time. Similarly, Lerch et al. [17] and Bjerkseter et al. [52] present a small estimate for installation cost.

Fig. 18 shows there is no consensus on which platform has the cheapest or the most expensive installation cost. [15,42] state that TLPs will be the most expensive platform, and this seems to be in line with the fact that the TLP will require specialised vessels for the more complex mooring system. Conversely, Ghigo et al. [38] expected the SPAR to be more expensive than the TLP, and this could be due to the higher difficulty related to handling the SPAR. Heidari et al. [59] found the SPAR to be the most expensive and semi-submersible to be the cheapest, in terms of installation costs: this is potentially due to the difficulty of handling related to the SPAR and the ease of handling of the semi-submersible.

Myhr et al. [51] and Bjerkseter et al. [52] both assume that the cost would be the same for all platform types. Given the difference in the geometry, this seems a substantial approximation, since each platform will require different installation techniques.

Fig. 19 shows the average installation cost for each platform found in the literature. Overall, the TLP is the most expensive, which is expected because of its more complex mooring system, which will take longer to install and require specialised vessels. It also has the largest range, this is potentially due to there being no TLPs installed as of yet. Leading to greater uncertainty in the installation process. Semi-submersibles are the cheapest, they have small easy to handle geometries and simple mooring arrangements. This platform is currently being used at the Kincardine site, combining this with the large amount of literature around semi-submersibles, this is expected to be the reason for the relatively small variation in cost.

5.2. Operation & maintenance expenditure

Operation and Maintenance is a highly complex cost to determine. A general decreasing trend has been identified as the wind farm capacity and distance to shore increases, highlighting the benefit of cost savings for a larger farm, see Fig. 20. There is, however, a slight variation in the mid-section of the graph which needs further explaining. Castro (2014) and (2016) et al. [18,42] have the same methodology which shows the decreasing trend in cost for the increased wind farm capacity and distance to shore. This model includes vessel hire and failure rates but it neglects the consideration of weather windows which would have a dramatic effect on downtime and revenue. This seems to be a very common assumption in all papers [15,42,43]. Maienza et al. [15] also have a relatively similar method, but the cost is substantially smaller for a wind farm which is not much larger. A reason for this could be assumptions of component failure rates, this is difficult to determine as the inputs are not given to compare. Lerch et al. [17] generally follow the trend of the data. This is expected to be because it follows a similar methodology to [15,18,42], however, they do not consider sea bed rental, insurance or transmission costs, which could be the reason for [17] being lower than anticipated. Heidari et al. [59], do not consider weather windows, component failure rates, or vessel hire. It is based on a function of distance which has been fitted to the data found in the literature. This model presents one of the lowest predicted values, which is potentially due to the fact it does not use failure rates, vessel hire, labour, etc. [51,52] provide a relatively small value for O&M, this model uses the OMCE-calculator. This calculator uses data, which would be accurate for fixed platforms, but the accuracy of this for floating is unsure. Since there are only two operational sites, there is no real data available for floating O&M as of yet.

Ghigo et al. [38] predicts a very small O&M cost compared to other literature with similar wind farm sizes. The assumption in this

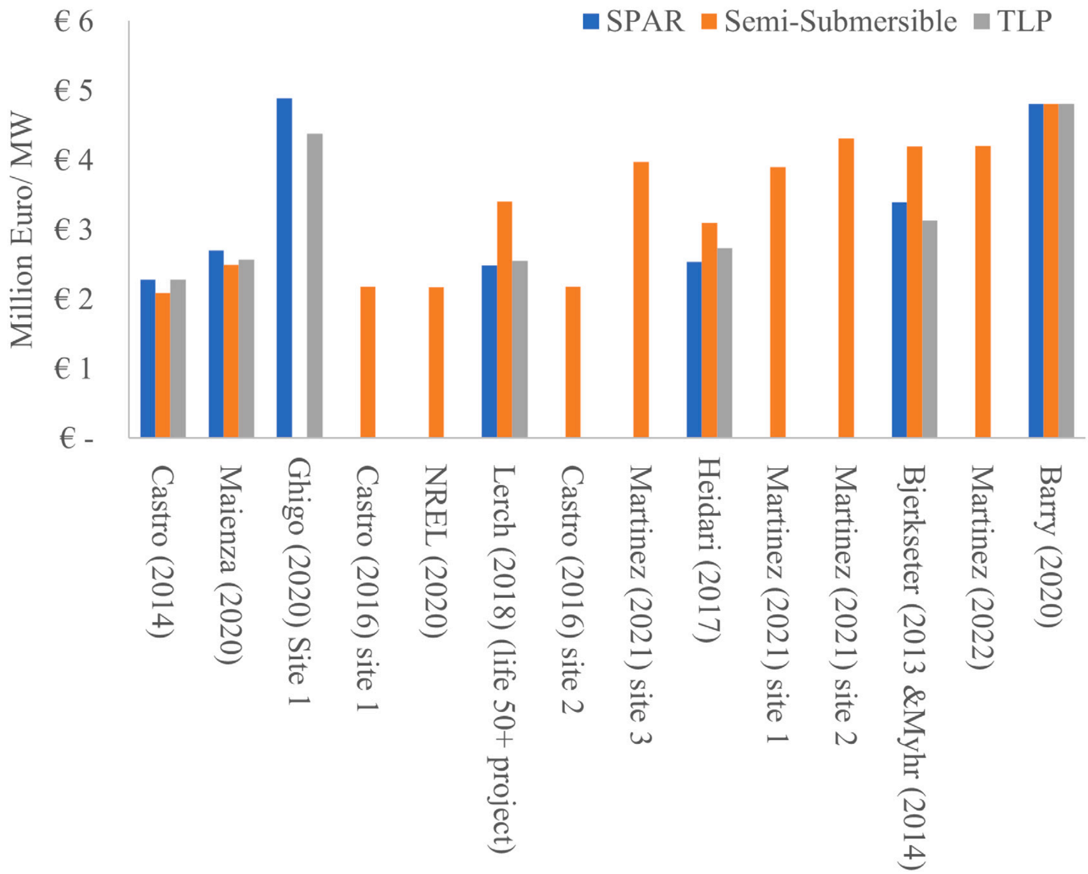

Fig. 16. Combined manufacturing cost for each typology found within literature represented in Million Euro/MW.

work is based on a Euro/MW value. Stehly et al. [60], similarly to the work carried out in [38], use a Euro/MW value for O&M. This is a relatively simple method to estimate O&M costs. Since O&M is heavily dependent on vessel costs, hire times, time to carry out work, weather windows, vessel availability, and component failure rates. Hence this is why values found in [38,60] are expected to be different from other wind farms with similar power capacities. Finally, the sites within Martinez et al. [47,48] do not follow the trend and create the 'bump' seen in Fig. 20. This model has a fixed yearly rate and a variable Euro/MW/km/year value to account for travel expenses. It should be noted that the calculation does not consider failure rates among other things. Based on the other data, this seems to be an overestimate.

A number of papers include more than one platform. It is unclear from this analysis which platform would have the most expensive and cheapest O&M. Castro (2014) et al. [42] highlight that the O&M for a TLP is the most expensive and the semi-submersible is the cheapest. This seems fair given TLPs have the most complex mooring system which is under high loading, exposing it to a higher likelihood of failure. Heidari et al. [59] claim that the Semi-submersible is the most expensive and the SPAR is the cheapest, potentially due to its simplicity. Lerch et al. [17] state the SPAR is the most expensive and the semi-submersible is the cheapest, which in general compared to the other papers goes against the general trend seen in Fig. 21. On the other hand [15,51,52] detailed that the O&M cost regardless of platform type would be the same. Similarly, Ghigo et al. [38] assumed the TLP and SPAR would also have the same O&M cost. It is clear from other literature and authors knowledge that this cost should be different for each platform [17,42,59].

The variation in data found in the literature is expressed in Fig. 21. This Figure highlights on average the semi-submersible has the cheapest O&M and SPAR and TLP are the same. The variation is expected to be larger as explained, no two models are the same and the level of detail varies heavily, causing the O&M cost outputs to vary heavily from paper to paper. Since the semi-submersible has been more heavily researched, there is potentially more consensus on how to accurately model the semi-submersible O&M cost, causing the variation to be slightly less than the other two platform types.

5.3. Decommissioning expenditure

The cost of decommissioning more regularly than not is dismissed and not considered. Only 30% of the papers found in the literature included a decommissioning cost model. A general trend found is that increasing the distance to shore and increasing the wind farm capacity causes a decline in decommissioning cost to negative values, see Fig. 22. A reason for this negative value seen in the literature is the revenue created from scrap materials. As wind farms expand in capacity, the mass of re-saleable material also increases. This is estimated to be more than the cost of hiring vessels and removing the farm.

This highlights that the assumptions made, such as neglecting decommissioning, or assuming it as a fixed % of CAPEX, may be substantially inaccurate, as the values are significant and sometimes negative.

Another reason for the decreasing trend in cost could be the cost–benefit of installing larger capacities, driving down the MEuro/MW/km. As previously analysed in the literature section, Castro (2014) et al. [42] have a cost model which is the same as their work presented in 2016 [18]. The work in 2014 and 2016 for two sites are included in Fig. 22. Considering their work utilises the same model, this trend of increased power and the general relationship of increased distance to shore with power. This solidifies the findings of decreasing DECEX cost with wind farm size.

Adedipe et al. [56] presents one of the best models of decommissioning, however, the case study used is for a fixed platform. The author

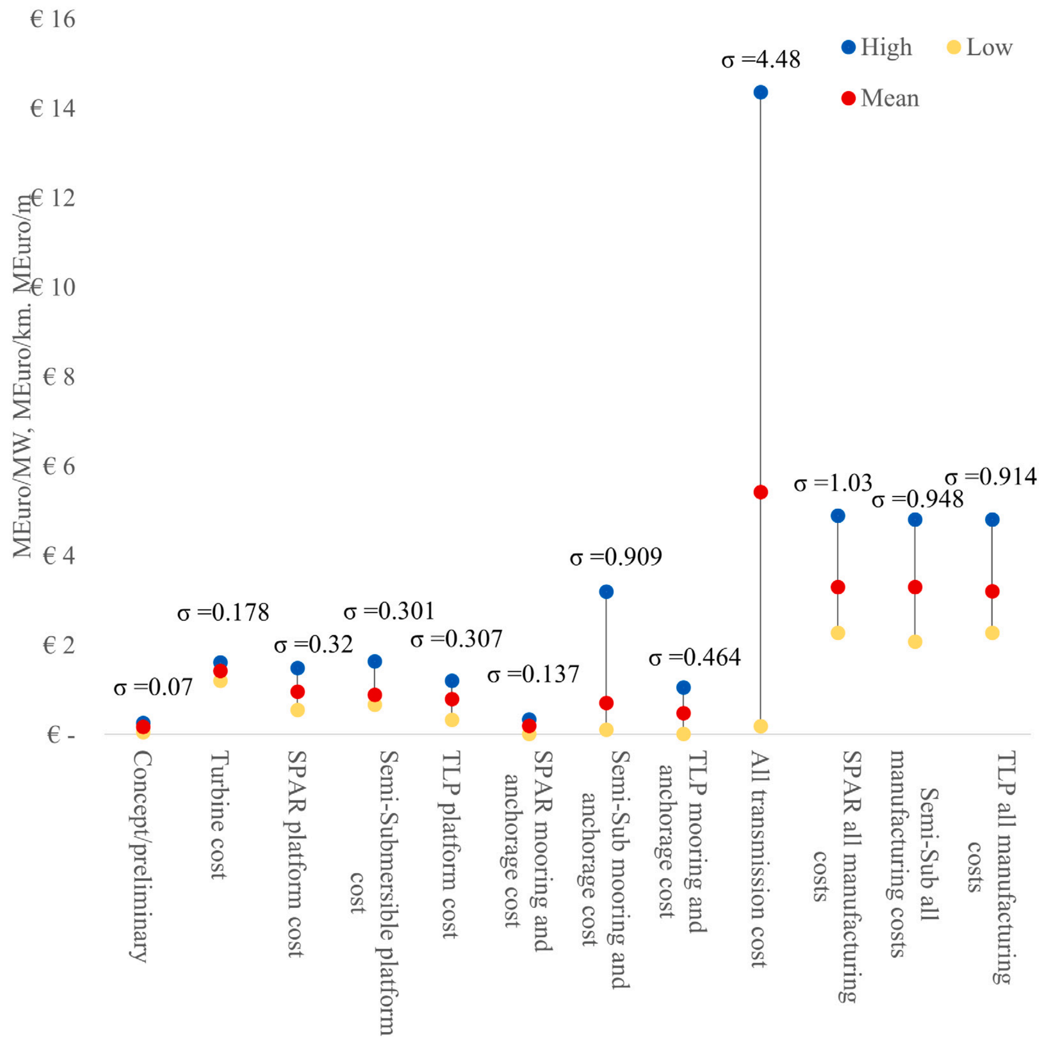

Fig. 17. Variation in manufacturing costs found within literature represented in MEuro/MW.

expects this cost would be less for a floating platform, as removal of the platform itself would be much easier. The mooring system is disconnected and then the platform is towed back to shore. Whereas fixed platforms, such as monopiles or jackets have to be cut, which requires vessels with such capabilities and a lot more time to carry out the task.

Maienza et al. [15] considers the DECEX a percentage of the installation cost, which, given that there is potential for revenue made from the re-saleable materials, may be considered inaccurate. [38] utilises a set 2% value of the CAPEX to determine DECEX, explaining the substantial overestimation in cost. The decommissioning cost in Lerch et al. [17] is so small that it was considered negligible, hence it is not shown in the Figs. 22 or 23.

[15,42,51,52] consider that each platform would have a different decommissioning cost, which is expected as each platform has a different geometry and hence there is potential for different vessel sizes required. The difference in the mooring system will also have an impact, as shown in Fig. 22: TLPs are expected to be the most expensive, this is logical considering their higher complexity mooring system. The semi-submersible is expected to be the cheapest in the work presented by Myhr et al. [51] and Bjerkseter et al. [52]. The expected reason for this is in comparison to a SPAR, the semi-submersible is easier to handle. However, it could be argued that the SPAR has a larger mass and hence greater revenue from recycled materials, explaining the work within [15]. More research on this area is crucial to understand this.

One of the main issues with predicting decommissioning cost is the lack of available data, and this data is expected to be available around 2035–2040 when the first sites which have been installed come to the end of their design life. The advantage of this is it would allow the models to be bench-marked with real-life data. This is likely to be the reason for the huge variation in cost estimations presented within the literature. This can be seen in Fig. 23.

5.4. Levelised cost of energy

The LCoE is one of the main outputs from most papers in this research area. In the present work it was highlighted that this substantially varies throughout the literature, as shown in Fig. 24, mainly due to the different assumptions and models adopted.

There are currently no Tension Leg Platforms being used in operational offshore sites, this is expected to be a main contributor to the large variation in costs related to TLPs. Since there is no operational site, current cost models cannot be benchmarked against them to improve the accuracy in predicting cost

Both the SPAR and the semi-submersible have been utilised hence these are expected to have smaller variations. This is true for the SPAR, Fig. 24 detailing this. The Semi-submersible has a slightly larger variation than the TLP, this is expected to be due to the fact that semi-submersibles have been covered the most in the literature. As highlighted previously a varying degree of detail is presented across all literature, causing the LCoE to be very different depending on which

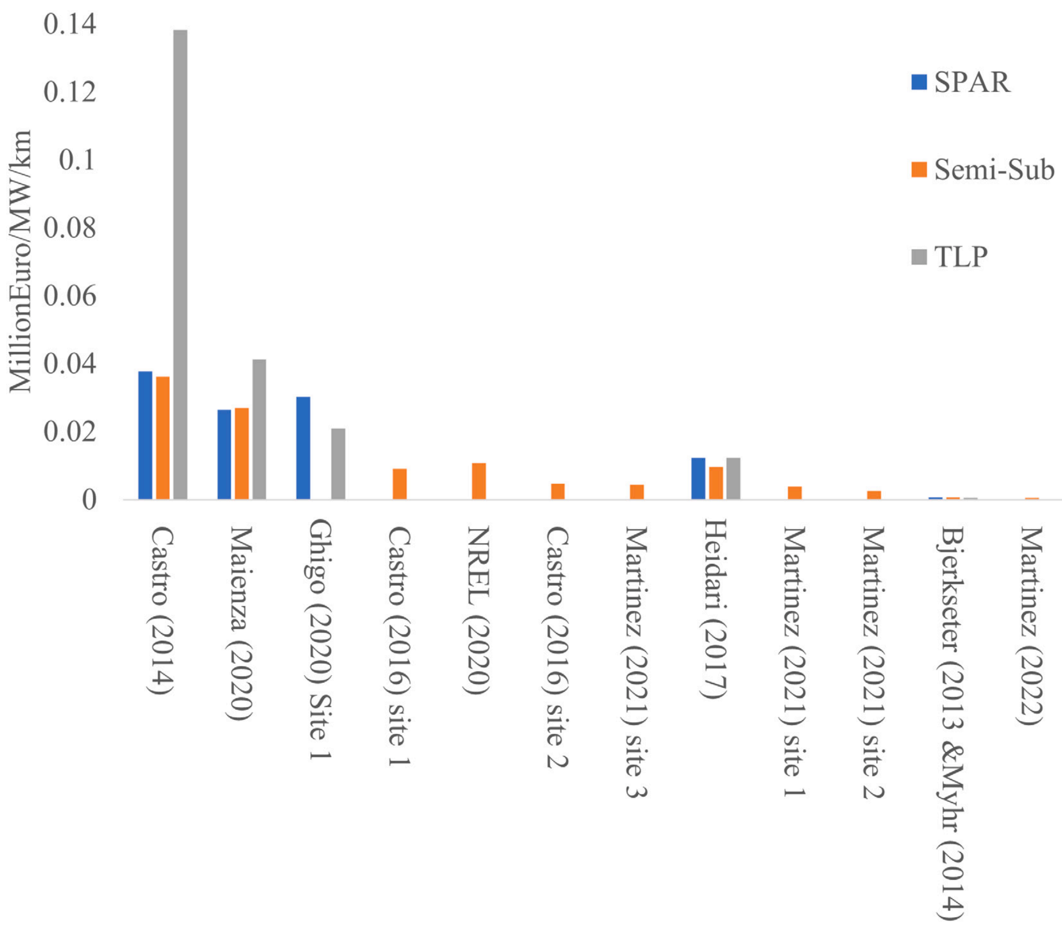

Fig. 18. The installation costs found within literature represented in MEuro/MW/km.

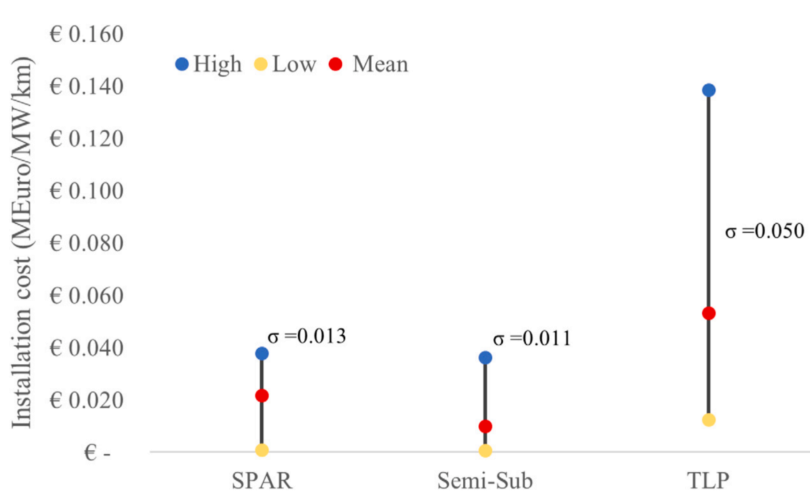

Fig. 19. The installation costs variation found within literature represented in MEuro/MW/km.

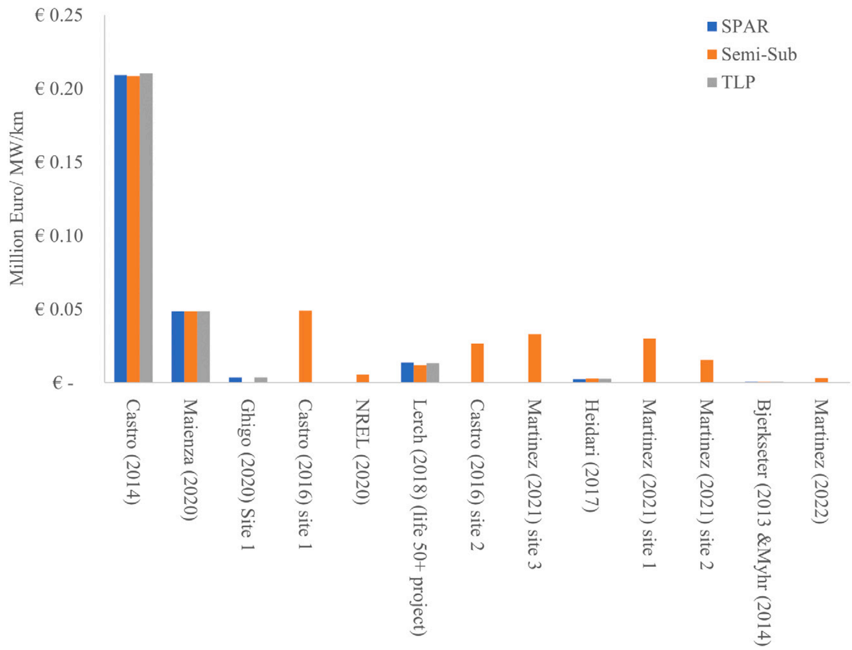

Fig. 20. The O&M costs found within literature represented in Million Euro/MW/km.

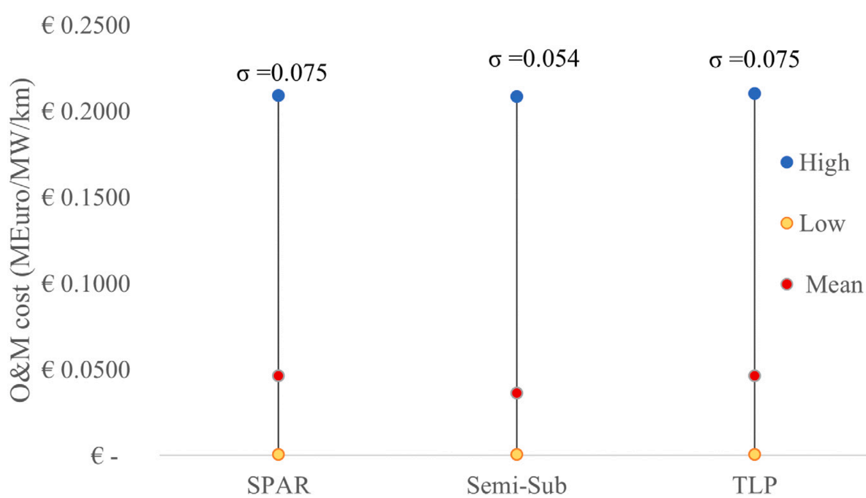

Fig. 21. The O&M costs variation found within literature represented in Million Euro/MW/km.

paper is considered. Another factor which leads to variation in LCoE is the fact that no two paper considered in this review has the exact same site, hence there will be differences in the resource and hence AEP, distance to shore, water depth and wind farm capacity.

6. Future work

By carrying out this review it has highlighted some clear areas of improvement in each section of the cost model. The most common estimation of preliminary works is based on a GBP/MW value, which seems sufficient given the majority of the literature uses a very similar value. However, there are some elements within the preliminary cost such as surveys which could be better expressed in a GBP/km value to better capture the distance to the site in the cost. Another way in which this could be further improved is to consider the cost of vessel hire, fuel cost, distance to shore and the vessel specifications along with the required crew and surveyors, giving a more accurate cost representation.

Manufacturing cost is a large area, some costs are relatively well defined such as the wind turbine. It can be seen from the literature that the majority of the turbines used are 5 MW. However, since the 15 MW Vestas prototype is in the testing phase the requirement to better determine the cost of larger turbines will become very important [65]. By creating a cost model which can include larger wind turbines, the cost information could be combined with the AEP model and it will help to determine if economies of scale are present, or if there is a maximum size of turbine where it no longer becomes economically feasible. To best determine the cost of the platform moving away from assumptions related to mass will improve the accuracy, by removing the bias towards higher mass platforms. Considering the mass, welding, painting and forming of the structures along with structural members would be a much more accurate way to determine the cost of each platform typology. For the transmission system, the inclusion of an HVDC transmission system in the work presented in [34] in all cost models will be essential for floating offshore wind since the distance to shore can increase rapidly, making conventional HVAC no longer feasible. In general, the mooring and anchors model could be better

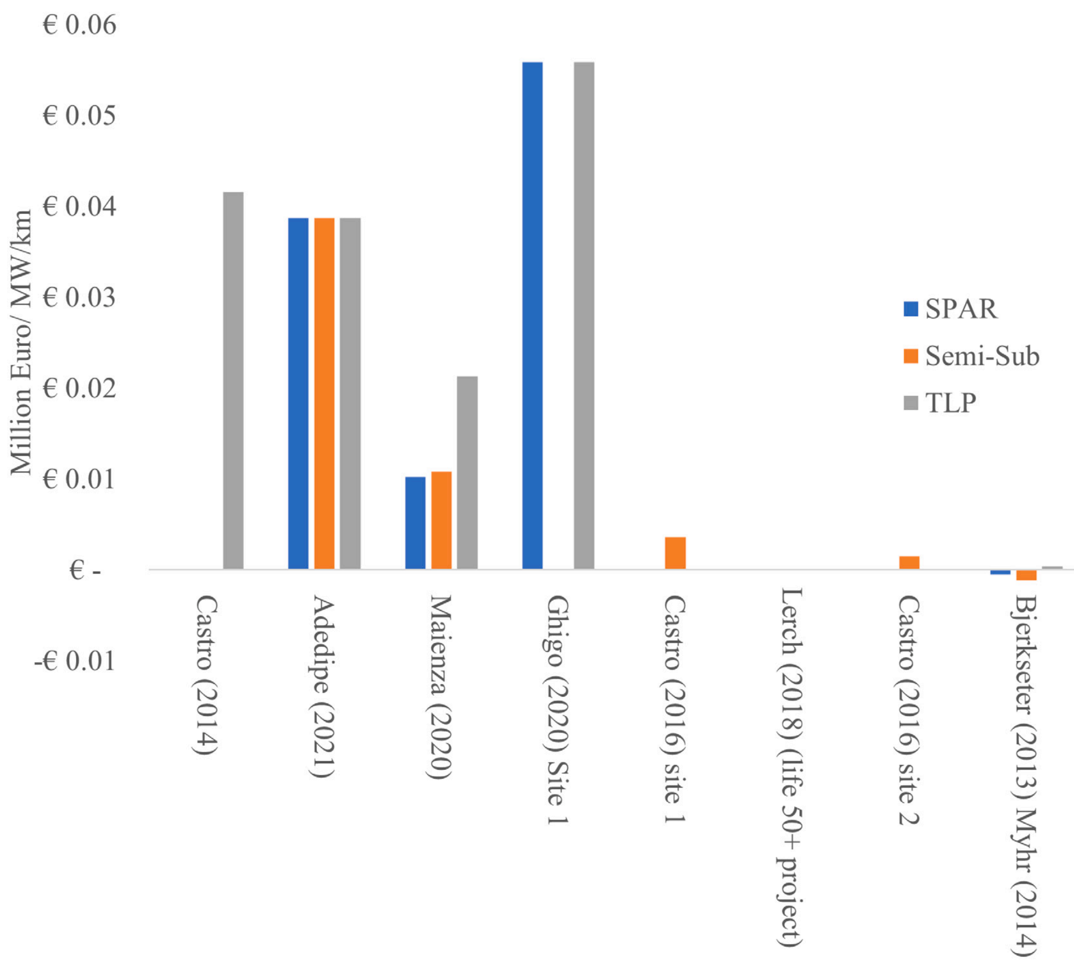

Fig. 22. The decommissioning costs found within literature represented in Million Euro/MW/km.

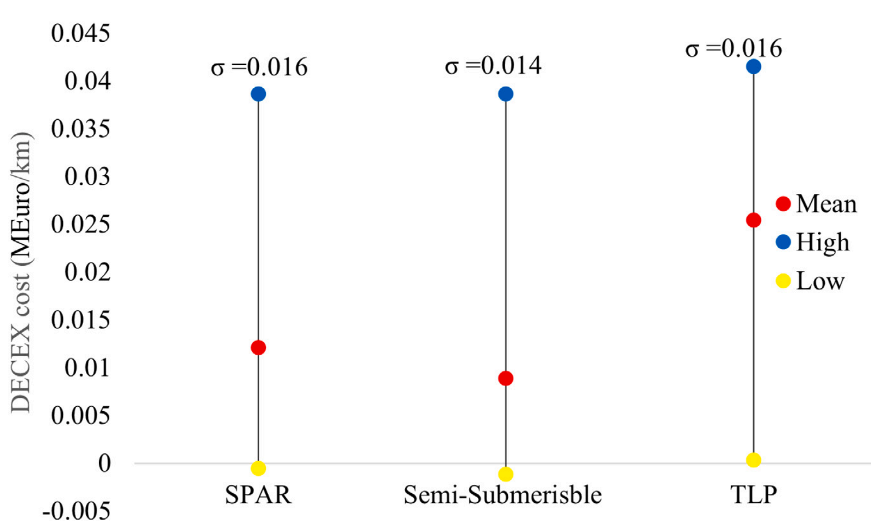

Fig. 23. The decommissioning costs variation found within literature represented in MEuro/MW/km.

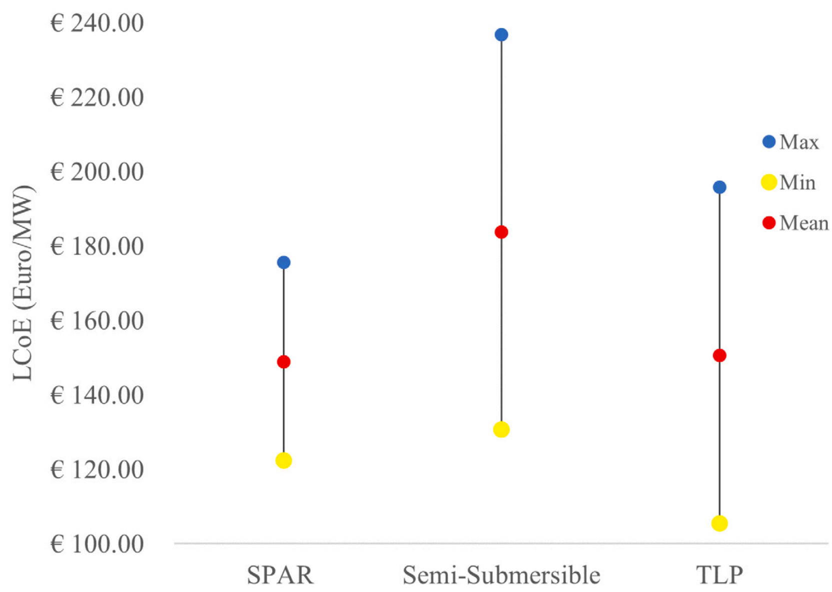

Fig. 24. The variation in the LCoE for each platform found in the literature.

improved by considering the appropriate mooring and anchor sizing based on the site characteristics.

In general, there is very little inclusion in the literature on transporting the platform and other sub-systems to the port where they are stored and eventually taken from port to site. It has been seen with other projects such as Seagreen that the platforms were built in a Chinese shipyard and then transported to Scotland to be installed [66]. This suggests there was a cost–benefit in building the platforms in China perhaps this was due to the lower price of steel or workforce, however, the transportation cost would have been significant and including such information in the cost model is important.

To refine the installation, O&M and decommissioning model considering the charter type is key. Having discussed with industry experts it is clear that in general, the charter type is a time charter, which does not include fuel costs. All vessel costs could then be more accurately presented. An accurate database representing how long it takes to install each sub-system would be useful, currently, it is vague and sometimes hard to determine how long the installation of each system would take.

In order to make a comprehensive O&M cost model combining the indirect costs such as sea bed rent, insurance, port storage and planning with the corrective and preventative maintenance considerations with failure rates for each individual platform type and sub-systems of the wind farm considered would create this improved model. A factor which is often neglected but should be included is available weather windows and potential downtime and loss of revenue due to lack of accessibility. This is a complex problem but one which should be addressed in order to better determine the overall O&M cost and LCoE. Decommissioning cost is very often neglected, and the accuracy of the current models is difficult to determine since the first floating offshore wind farms have only been in operation for a maximum of a few years, however, more work could be done to improve the accuracy.

The inclusion of an AEP model is essential to determine the performance and cost-effectiveness of a wind turbine, with only very few models actually considering this. A future step could be to consider the platforms motions within the AEP model allowing a more accurate representation of LCoE to be calculated. Another factor which is linked to energy production is the losses experienced by the turbine, there are a few papers which include all of the losses, however, this is something that could potentially be more accurately expressed since there is quite a large variation in the literature in percentage for each loss.

Overall, work done to create a complete model which considers all elements of the wind farm would be very beneficial and allow the user to determine the potential wind farms cost. However, based on this research a modified LCoE could also be useful to best determine which platform is cheapest, this could be expressed as an equivalent LCoE. By removing costs which are not affected by the platform type such as preliminary, electrical transmission system and the wind turbine. This could allow the user to determine which platform is the cheapest based only on costs which can carry depending on the platform choice such as manufacturing of the platform and mooring system, installation, operations and maintenance and decommissioning. When determining the cheapest platform the cost of full-life operation is important, particularly considering the variation in monetary cost over the years of operation, which could be an improvement to some of the existing models. By considering the cost over the life of the project, better-informed decisions can be made on whether to have a higher capital, but a lower OPEX or vice-versa throughout the life of the project. This would be an interesting comparison to see the three main platform types on where the trade-off point is between the CAPEX and OPEX. By doing so this might highlight a different ranking in terms of cost for the platforms, which is important given the requirement to reduce cost and make floating offshore wind competitive with other renewable energy sources.

7. Conclusion

The purpose of this work was to identify how the cost of floating offshore wind could be more accurately expressed. By finding weaknesses in the current literature it is hoped that they can be improved in future models to help prove floating offshore wind to be competitive when compared with other renewable energy types. The benefit of more accurate cost models is the potential to discover areas which could have potential cost savings, helping to drive down the cost. An example could be alternative geometries to reduce material and hence cost.

The aim of this paper was to determine the variation in the cost models found within the existing literature allowing the author to identify potential areas and assumptions which have led to these uncertainties. In order to compare the literature, data from each paper was collected and made adimensional. The mean value and standard deviation across the literature were found which could be easily compared.

From this work, it is clear that there is space to improve current cost models. The data review shows the differences in cost estimates in the literature due to the variation of assumptions and exclusions in each model. A number of things highlighted which could potentially improve the accuracy of the cost model are: including the charter type, fuel costs, weather windows, losses due to downtime, improved AEP models and the manufacturing costs for the platform removing the bias to higher mass platforms being more expensive.

In general, combining some of the current models to create a complete comprehensive model would be useful. However, when it comes to determining the cheapest platform perhaps using an equivalent LCoE which only considers costs which vary with platform type would be more appropriate and less work.

Overall, this review paper was successful in identifying a number of areas which could be worked on to improve the accuracy in predicting the cost of floating offshore wind farms.

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

No data was used for the research described in the article.

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Appendix A. Supplementary data

Supplementary material related to this article can be found online at https://doi.org/10.1016/j.rser.2023.113634.

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