Journal of
Marine Science and Engineering

MDPI

Article

The Technical and Economic Feasibility of the CENTEC Floating Offshore Wind Platform

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Abstract: This paper defines a methodology for the economic feasibility analysis of a floating offshore wind farm composed of tensioned leg platforms, which are part of the EU ARCWIND research project. In this context, the phases and subphases of its life-cycle process are considered to deal with aspects such as bathymetry, characteristics of the platforms, distance from the farm to shore, distance from the farm to port and offshore wind speed. All the costs and other external parameters such as capital cost, electric tariff, interest rate, percentage of financing and corporate tax have been analysed to calculate the internal rate of return, net present value, discounted pay-back period and levelized cost of energy of the farm. This work studies a farm composed of TLP offshore wind platforms designed by CENTEC and located at Ribadeo in Spain. Results indicate the costs and the economic feasibility of this platform for deep waters. They indicate that the platform is economically feasible for the location selected.

Keywords: CENTEC-TLP; Tensioned Leg Platform; offshore wind; economic feasibility; *IRR*; *NPV*; LCOE

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Citation: Filgueira-Vizoso, A.; Castro-Santos, L.; Iglesias, D.C.; Puime-Guillén, F.; Lamas-Galdo, I.; García-Diez, A.I.; Uzunoglu, E.; Díaz, H.; Guedes Soares, C. The Technical and Economic Feasibility of the CENTEC Floating Offshore Wind Platform. *J. Mar. Sci. Eng.* **2022**, *10*, 1344. https://doi.org/10.3390/jmse10101344

Academic Editor: Raúl Guanche García

Received: 1 September 2022
Accepted: 16 September 2022
Published: 21 September 2022

1. Introduction

Wind energy is produced onshore and offshore. Taking advantage of the fact that 70% of the planet's surface is covered by water and that a small percentage of wind energy is offshore, for example, in Europe in 2020, 16.4% of electricity demand was covered with wind energy, and within this 13.4% was onshore [1]; only the remaining 3% was offshore.

The production of offshore wind energy is made by fixed and floating platforms. Within the fixed ones, mention can be made of monopiles [2–4], tripod [5–7], tripilote, gravity [8,9] and jacket [10], and within the floating ones the main ones are: Semi-submersible [11], TLP (tensioned leg platform) [12] and Spar [13].

This paper describes a method of determining the economic feasibility analysis of a floating offshore wind farm [14–17] composed of CENTEC-TLP (tension leg platform) devices, which are part of the ARCWIND research project. For this purpose, the phases and subphases of its life-cycle process were considered, taking into account several inputs for this implementation: bathymetry, characteristics of the platforms, distance from farm to shore, distance from farm to port and offshore wind speed. Therefore, the method proposed allows the user vary some important inputs in order to know their influence in the main economic parameters. This is important because the majority of the studies consider general costs but not specific ones. All the costs and other external parameters such as capital cost, electric tariff, interest rate, percentage of financing and corporate tax have been taken into account to calculate the cash flows of the farm. This was the basis for calculating the main economic feasibility parameters: internal rate of return (*IRR*), net present value (*NPV*), discounted pay-back period (DPBP) and levelized cost of energy (LCOE) of the considered offshore wind farm [18–24]. Different researchers have developed methodologies for calculating the LCOE, and this calculation can be applied to different sectors, for example, Ueckerdt et al. [21] analyse as system LCOE allow the economic comparison of generating technologies and deriving optimal quantities in particular for VRE (variable renewable sources), Johnston et al. [22] review the challenges of accurately estimating levelized cost of energy (LCOE) for offshore wind outlining differing approaches to calculating LCOE, the factors influencing this, and the impact of variation in LCOE calculation. This paper studies a farm composed of the TLP offshore wind platform designed by CENTEC and located at Ribadeo in the northwest of Spain. Results will indicate the economic feasibility of the TLP platform.

2. Materials and Methods

2.1. Technical Feasibility

The CENTEC-TLP is a steel hull with a DTU-10MW turbine. The platform is detailed in [25]. It may be regarded as a free-float capable TLP. It attains this behaviour through a towing mode that resembles the behaviour of a barge platform. Once towed to the location, it is then installed to perform as a TLP [26].

The tension leg platform is overall lighter than other hulls as it replaces the reliance on hull form to attain stability using mooring lines. When it comes to the offshore wind sector, most works [12,27] try to use the SeaStar hull form [28] to keep the low mass advantage. This idea originates from the older MIT/NREL design [29]. However, this hull form is limited in application. Even in the oil and gas sector, only 5 of over 30 TLPs prefer this geometry [30], with the latest installation being in 2007. Despite a large number of designs, the impracticality of the hull form is apparent: there are no demo projects with TLPs despite both SPAR and Semisubmersible hull forms [31] being installed and operational as wind farms already.

Despite the large number of works using the SeaStar, the conventional TLP form is Conoco Phillips' Hutton in 1984, similar to a floating production system (e.g., [32]) regarding its use of ring pontoons underwater. This hull form is more suitable for addressing the technical challenges imposed by the wind industry. TLP's disadvantages are primarily associated with the stages up to when it is installed and operational. Its instability without its mooring lines forces alternative solutions such as additional barges.

At this point, it should be considered that multiple offshore wind platforms need to be installed on farms. For this reason, the oil-and-gas-sector experience does not translate well into the offshore wind case. It may be economically feasible to carry one platform to the installation location at a high price for oil and gas. On the other hand, when it comes to offshore wind, this operation may need to be repeated up to 100 times, depending on the size of the wind farm. Hence, the hiring costs of specialized vessels accumulate. For similar reasons, recent studies emphasize improving production speeds using modular production methods (e.g., tension leg platforms as explained in [33,34]).

Another problem lies in the towing locations. The assumption that the structure needs to be towed into the installation area using standard vessels after being assembled at the shore, signifies that it needs to have small motions in waves. The movements should be limited so that the high centre of gravity of the turbine and the tower do not impose stability issues. It needs to also do that at a low draft so that the hull can be towed from most ports. For instance, a draft of 20 m would significantly limit the locations where the platform can be towed from considering that the average draft of ports is below 10 m. Another consideration is the commercial availability of mooring lines used and the maximum stress allowance imposed by [35]. The goal is to adhere to regulations without requiring specially produced mooring lines.

The CENTEC-TLP addresses the problems listed above through its hull form. It acts as a stable barge when towed, and once installed, it performs as a TLP. Its dynamics in both forms have been experimentally and numerically verified [26,36,37].

2.2. Economic Feasibility

2.2.1. Economic Feasibility Parameters Analysed

The objective of this section is to carry out the economic feasibility analysis of the TLP platform. The economic viability of the project can be calculated by different highly effective methods. To determine the economic viability of this project, the Cash Flow is calculated throughout its useful life, as well as various economic parameters:

- Net Present Value (*NPV*).
- Internal Rate of Return (*IRR*).
- Discounted Pay-Back Period (DPBP).
- Levelized Cost Of Energy (LCOE)

2.2.2. Net Present Value (*NPV*)

The Net Present Value (*NPV*), in €, is the net value of the cash flows of the floating offshore wind farm, taking into account its discount from the beginning of the investment [38–40]. It is dependent on the cash flow in year t (CF_t), the discount rate (r) and the initial investment (G_0), as Equation (1) is shown.

$$NPV = -G_0 + \sum_{t=1}^{n} \frac{CF_t}{(1+r)^t} \tag{1}$$

The discount rate (r) considered for the financed project is the *WACC* (weighted average cost of capital). It was calculated using the equation.

- $NPV > 0$. The investment will generate earnings above the required return (r). This will imply that the acceptance of the project is recommended
- $NPV < 0$. The investment produces returns below the required minimum return (r). It is not recommended to accept the project.
- $NPV = 0$. The project does not add monetary value above the required profitability (r). The decision must be based on other criteria such as obtaining a better position in the market.

2.2.3. Internal Rate of Return (*IRR*)

The internal rate of return is the interest generated by the project throughout its useful life. Mathematically, it is defined as the discount rate that cancels the *NPV*, that is, the interest rate that makes the future flow of funds financially equivalent to the initial outlay.

$$-G_0 + \sum_{t=1}^{n} \frac{CF_t}{(1+IRR)^t} = 0 \tag{2}$$

The economic feasibility of the project will depend on the *IRR*:

- $IRR <$ k. The profitability obtained from the project is less than the minimum required, so the investment is not recommended.
- $IRR >$ k. The profitability of the project is above the minimum required, therefore, it is recommended to decide to invest.
- $IRR =$ k. The profitability is the same as that required, the same happens as in the case where the $NPV = 0$, the decision is conditioned by other factors

2.2.4. Discounted Pay-Back Period (DPBP)

Discounted pay-back period (DPBP), in years, considers the cash flow of each year with the respective discount rate and adds it to all the previous cash flows with their respective discount rate, accumulating its *NPV*. When this sum is equal to or greater than the initial investment, this is the year of the DPBP, as Equation (3) is shown. The best DPBP is as low as possible.

$$\sum_{t=1}^{n} \frac{CF_t}{(1+r)^t} \geq G_0 \tag{3}$$

The conditions regarding the feasibility of the project are:

- DPBP <<< *t*. The initial outlay takes less time to recover than the life of the project (t). Accept project.
- DPBP = *t*. The initial outlay takes to recover the same as the life of the project (t). Indifferent.
- DPBP > *t*. The initial outlay takes longer to recover than the life of the project (t). Reject the project.

2.2.5. Levelized Cost of Energy (LCOE)

The levelized cost of energy (*LCOE*), in €/MWh, has been calculated considering the total costs of the farm (LCC_t) in €, the energy produced by the floating offshore wind farm (E_t) in MWh/year and the capital cost of the project (r) [41].

$$LCOE = \frac{\sum_{t=0}^{t=N_{farm}} \frac{LCC_t}{(1+r)^t}}{\sum_{t=0}^{t=N_{farm}} \frac{E_t}{(1+r)^t}} \tag{4}$$

The total costs of the farm for the year t LCC_t are calculated in the next sub-section of the paper (LCC_t is CAPEX + OPEX). On the other hand, the energy production of the floating offshore wind farm (E_n) in kWh/year has been estimated by multiplying the energy produced by each offshore wind turbine by the number of wind turbines (NWT) [41]. The energy produced by one offshore wind turbine is dependent on the total hours per year (factor 8.76), the reduction due to losses (η), the power curve of the offshore wind turbine ($P_{PC}(v)$) and the Weibull density probability function ($p_{Weibull}$), whose value will depend on the wind speed (v), the wind scale parameter (c_w) and the wind shape parameter (k_w) of the location of the European Atlantic Arc selected.

$$E_n = NWT \cdot 8.76 \cdot \eta \cdot \int_0^{v_{cut-out}} P_{PC}(v) \cdot p_{Weibull}(v; c_w; k_w) dv \tag{5}$$

where:

$$p_{Weibull}(v; c_w; k_w) = \frac{k_w}{c_w} \cdot \left(\frac{v}{c_w}\right)^{k_w - 1} \cdot e^{-\left(\frac{v}{c_w}\right)^{k_w}} \tag{6}$$

The power curve (P_{PC}) will be integrated into three zones which depend on the power of the wind turbine in MW and on the characteristic wind speed (in m/s) [41]: cut-in wind speed, rated wind speed and cut-out wind speed ($v_{cut-out}$).

2.2.6. Costs

The total cost of the farm (see Equation (5)) is necessary for calculating the LCOE and some aspects of the cash flow [14,42,43]. The costs are divided into the phases in which the wind farm passes during its life cycle. Each phase is formed by several subphases, which are determined by the components or factors that must be considered to obtain the costs in each case. In this way, the total cost of of an offshore wind farm is obtained from Equation (1) (Castro-Santos & Diaz-Casas, 2014).

$$LCC = C_1 + C_2 + C_3 + C_4 + C_5 + C_6 \tag{7}$$

where:

- C_1: Conception and definition cost.
- C_2: Design and development cost.
- C_3: Manufacturing cost.
- C_4: Installation cost.
- C_5: Exploitation cost.
- C_6: Dismantling cost.

It is important to notice that there are costs that exist during all the years of the project such as the exploitation cost and other costs that are considered only in the initial years of the project, when it is been built (conception and definition cost, design and development cost, manufacturing cost and installation cost). Finally, there are costs, such as the dismantling cost, that are expended in the last year of the project (N_{farm}).

The main cost items are shown in Table 1.

Table 1. Main variables.

Variable	Concept	Units
EPCIC	EPCIC stands for Engineering, Procurement, Construction, Installation & Commissioning (contract)	%
OffshoreSiteR	Offshore site renting	€
Nplatforms	Number of floating platforms	platforms
C_{emet}	Meteorological structure cost	€
C_{smet}	Meteorological sensors cost	€
C_{samet}	Auxiliary meteorological systems cost	€
EvaluationReportCost	Evaluation report cost	€/MW
TurbineP	Power of the wind turbine	MW
GeophysicalDailyCost	Geophysical campaign cost (bathymetry, sub bottom profiler, garbage, wreck detections, etc.)	€/day
GeophysicalDays	Duration of the geophysical campaign	days
GeotechnicalDailyCost	Geotechnical campaign cost (CPT: cone penetration tests)	€/day
GeotechnicalDays	Duration of the geotechnical campaign	days
$C_{insurance}$	Insurances coefficient	€/MW
TravellingCosts	Travelling costs of the preparation of the project	-
Staff	Number of staff of the project enterprise	staff
AverageCostY	Staff average cost per year	€/year
Years0	Number of years until year 0	years
OfficeRentingM	Office renting per month	€/month
RatioWTGPriceCosts	Ratio between wind turbine generator price and its costs	-
Nplatforms	Number of floating platforms	platforms
FEED	Drafting Costs	€
DetailDesignCosts	Detailed design costs	€
TankTestingInplace	Tank testing-inplace cost (based on other similar projects)	€
TankTestingTransport	Tank testing-transport cost (based on other similar projects)	€
PreliminaryWorksYardCosts	Preliminary works at yard Costs	€
OneDrydockCost	One dry dock costs	€
$N_{drydocks}$	Number of drydocks	docks
C_{3241}	Renting on harbour area cost for foundations	€
C_{3242}	Renting on harbour area cost for generator	€
C_{3243}	Renting on harbour area cost for office	€
C_{3244}	Renting on wet harbour area cost	€
PreparingSeabedCost	Cost of preparing the seabed for one unit	€
TotalMaterialCostPlatform	Total cost of the materials of the platforms considering scale economy	€
CraneDrydockConstructionCostYT	Crane dry dock construction cost	€
CraneDrydockSupportCostYT	Crane dry dock support cost	€
HarbourInternalTowingYears	Number of years neccesary for the harbour internal towings	years
TugMobDemobCost	Cost of mob or demob the tug	€
BollarPullTugDR	Daily rate associated with a bollard pull tug (65 tonnes)	€/day

Table 1. *Cont.*

Variable	Concept	Units
$N_{DiversPlat}$	Number of divers per platform	divers
$DiverDailyCost$	Daily cost associated with one diver	€/day
$DiverDaysIntervention$	Days that the diver need for each intervention	days
$N_{AccessesPlat}$	Number of accesses per platform	-
$PlatformAccessCost$	Platform access cost (1 unit)	€/platform
$N_{InternalsTower}$	Number of internals per tower	-
$TowerInternalsCost$	Tower internals cost (1 unit)	€/platform
$N_{JTubesPlat}$	Number of J-tubes per platform	j-tubes
$JTubeCost$	J-tube cost (per unit)	€/j-tube
$ReductionFactorBallast$	Reduction factor (economy of scale) for the ballast system	-
$TotalBallastCostPlat$	Total Ballast Cost platform	€
$N_{SetsCommunicationPlat}$	Number of sets (communication system) per platform	-
$ReductionFactorCommunication$	Cost of 1 communication system	€
$CommunicationSystemCost1$	Reduction factor (economy of scale) for the communication system	-
$N_{SetsLightingPlat}$	Number of sets (lighting system) per platform	-
$LightingSystemCost1$	Cost of 1 lighting system	€
$ReductionFactorLighting$	Reduction factor (economy of scale) for the lighting system	-
$PlatformMonitoringCost$	Platform monitoring cost (inclinometer and others) (1 platform)	€/platform
$StructuralMonitoringCost$	Structural monitoring cost	€
C_{33}+ C_{34}	Mooring and anchoring manufacturing cost	€
C_{351}	Electric cable manufacturing cost	€
C_{352}	Substation manufacturing cost	€
C_{411}	Cost of installation of turbines at port	€
C_{412}	Cost of the transport of the turbines	€
C_{413}	Cost of installation of turbines offshore	€
C_{42}	Cost of installing the floating TLP platforms	€
C_{abarge}	Cost of installing mooring and anchoring of a barge per day	€/day
C_{atug}	Cost of installing mooring and anchoring of a tug per day	€/day
C_{aaMOD}	Cost of labour per day for installing mooring and anchoring	€/day
$C_{aapumpsanddivers}$	Cost of divers	€/day
$N_{anchoring}$	Number of anchors	anchors
$T_{instbarge}$	Time of installing mooring and anchoring	Anchors/day
$BurialCableCost1Plat$	Cost associated with the burial cable intertidal area for 1 platform	€/platform
$HDDCost1Plat$	Cost associated with the HDD horizontal drilling for 1 platform	€/platform
$DynamicCableInstallationCost1Plat$	Cost associated with the dynamic cable installation for 1 platform	€/platform
$ExportCableInstallationCost$	Export cable installation cost	€
$CableMechanicalProtectionCost$	Cable mechanical protection cost	€
$CableBurialIntertidalAreaCost$	Cable burial (intertidal area) cost	€
$InterarrayCableCommissioningCost$	Interarray cable commissioning cost	€
$ExportCableCommissioningCost$	Export cable commisioning cost	€
C_{51}	Cost of assurance	€
C_{521}	Data acquisition (SCADA) cost	€
C_{522}	SAP & Maritime coordination costs	€
C_{523}	Meteorological prediction cost	€
C_{524}	Administration cost	€
C_{531}	Turbine maintenance cost	€
C_{532}	Export cable and grid connection maintenance	€
C_{533}	Interarray cable survey and repairs cost	€
C_{534}	Substructure maintenance	€
N_{farm}	Number of years of life-cycle of the farm	Years
C_{54year}	Onshore logistics costs per year	€/year
$C_{551year}$	Workboats costs per year	€/year

Table 1. *Cont.*

Variable	Concept	Units
$C_{552year}$	Helicopter costs per year	€/year
$C_{553year}$	Crane barge service costs per year	€/year
$C_{554year}$	Offshore accommodation (if any) cost	€/year
$PD_{turbine}$	Percentage of dismantling turbine and platform	-
$PD_{mooring}$	Percentage of dismantling mooring	-
PD_{cable}	Percentage of dismantling cable	-
$PD_{substation}$	Percentage of dismantling substation	-

Conception and definition costs (C_1) depend on legal aspects (C_{11}) and offshore wind farm certification costs (C_{12}). Particularities and differences between legal aspects exist for the countries where the offshore wind farm could be located. Therefore, it would be advisable to go deeper into each case so that the costs would vary.

$$C_1 = C_{11} + C_{12} \tag{8}$$

The legal aspects' cost (C_{11}) depends on the offshore site renting (*OffshoreSiteR*) and the number of wind devices (*Nplatforms*).

$$C_{11} = OffshoreSiteR \cdot Nplatforms \tag{9}$$

The offshore wind farm certification cost (C_{12}) depends on the cost of the offshore wind farm certification (C_{121}), the meteorological research cost (C_{122}), the environmental impact assessment (C_{123}), the geophysical campaign cost (C_{124}), the geotechnical campaign cost (C_{125}) and the initial insurances project cost (C_{126}).

$$C_{12} = C_{121} + C_{122} + C_{123} + C_{124} + C_{125} + C_{126} \tag{10}$$

where:

$$C_{121} = (1 + EPCIC) \cdot OffshoreSiteR \cdot Nplatforms \tag{11}$$

$$C_{122} = (1 + EPCIC) \cdot (C_{emet} + C_{smet} + C_{samet}) \tag{12}$$

$$C_{123} = (1 + EPCIC) \cdot EvaluationReportCost \cdot N_{platforms} \cdot TurbineP \tag{13}$$

$$C_{124} = (1 + EPCIC) \cdot GeophysicalDailyCost \cdot GeophysicalDays \cdot N_{platforms} \tag{14}$$

$$C_{125} = (1 + EPCIC) \cdot GeotechnicalDailyCost \cdot GeotechnicalDays \cdot N_{platforms} \tag{15}$$

$$C_{126} = C_{insurance} \cdot N_{platforms} \cdot TurbineP \tag{16}$$

The design and development cost (C_{21}) depends on the travelling costs for the preparation of the project (*TravellingCosts*), the number of staff for the project enterprise (*Staff*), the staff average cost per year (*AverageCostY*), the number of years until year 0 of the project (*Years*0) and the office renting per month (*OfficeRentingM*).

$$C_2 = C_{21} \tag{17}$$

where:

$$C_{21} = (1 + TravellingCosts) \cdot (12 \cdot Staff \cdot AverageCostY \cdot Years0 \cdot OfficeRentingM) \tag{18}$$

On the other hand, manufacturing costs (C_3) will be explained from the sub-phases that constitute an offshore wind farm. The manufacturing costs depend on generator manufacturing costs (C_{31}), floating platform manufacturing cost (C_{32}), mooring manufacturing cost (C_{33}), anchoring manufacturing cost (C_{34}) and electric system manufacturing cost (C_{35}).

$$C_3 = C_{31} + C_{32} + C_{33} + C_{34} + C_{35} \tag{19}$$

The generator manufacturing cost (C_{31}) depends on the costs of turbine components (*ComponentsCost*10*MWturbine*), the ratio of power and size of the turbine considered (*RatioWTGPriceCosts*) and the number of platforms (*Nplatforms*).

$$C_{31} = ComponentsCost10MWturbine \cdot RatioWTGPriceCosts \cdot Nplatforms \tag{20}$$

The floating platform manufacturing cost (C_{32}) depends on the platform engineering cost (C_{321}), the tank testing cost (C_{322}), the manufacturing facilities—civil work costs (C_{323}), the manufacturing facilities—renting on harbour area cost (C_{324}), the manufacturing facilities—other costs (C_{325}), the materials and manufacturing costs of externals (C_{326}), the substructure assembly cost of external works (C_{327}), the harbour's internal towing cost (C_{328}), the divers (harbour operations) cost (C_{329}), the external access cost (C_{3210}), the tower internals costs (C_{3211}), the J tubes-cable access cost (C_{3212}), the ballast (if any) system cost (C_{3213}), the communication system cost (C_{3214}), the emergency system (if any) cost (C_{3215}), the lighting and other signs cost (C_{3216}), the monitoring system cost (C_{3217}), the safety equipment cost (C_{3218}) and the crew transfer vessels during construction cost (C_{3219}).

$$\begin{gathered} C_{32} = C_{321} + C_{322} + C_{323} + C_{324} + C_{325} + C_{326} + C_{327} + C_{328} + C_{329} + C_{3210} + C_{3211} + C_{3212} + C_{3213} \\ + C_{3214} + C_{3215} + C_{3216} + C_{3217} + C_{3218} + C_{3219} \end{gathered} \tag{21}$$

where:

$$C_{321} = FEED + DetailDesignCosts \tag{22}$$

$$C_{322} = TankTestingInplace + TankTestingTransport \tag{23}$$

$$C_{323} = PreliminaryWorksYardCosts + OneDrydockCost \cdot N_{drydocks} \tag{24}$$

$$C_{324} = C_{3241} + C_{3242} + C_{3243} + C_{3244} \tag{25}$$

$$C_{325} = N_{platforms} \cdot PreparingSeabedCost \tag{26}$$

$$C_{326} = TotalMaterialCostPlatform \tag{27}$$

$$C_{327} = CraneDrydockConstructionCostYT + CraneDrydockSupportCostYT \tag{28}$$

$$C_{328} = HarbourInternalTowingYears \cdot \left(TugMobDemobCost + \frac{N_{platforms}}{HarbourInternalTowingYears} \cdot 2.5 + TugRentingDaysY \right) \tag{29}$$

$$C_{329} = N_{platforms} \cdot N_{DiversPlat} \cdot DiverDailyCost \cdot DiverDaysIntervention \tag{30}$$

$$C_{3210} = N_{platforms} \cdot N_{AccessesPlat} \cdot PlatformAccessCost \tag{31}$$

$$C_{3211} = N_{InternalsTower} \cdot TowerInternalsCost \cdot N_{platforms} \tag{32}$$

$$C_{3212} = 0 \tag{33}$$

$$C_{3213} = N_{platforms} \cdot N_{JTubesPlat} \cdot JTubeCost \tag{34}$$

$$C_{3214} = 0 \tag{35}$$

$$C_{3215} = ReductionFactorBallast \cdot N_{platforms} \cdot TotalBallastCostPlat \tag{36}$$

$$C_{3216} = N_{platforms} \cdot N_{SetsCommunicationPlat} \cdot ReductionFactorCommunication \cdot CommunicationSystemCost1 \tag{37}$$

$$C_{3217} = 0 \tag{38}$$

$$C_{3218} = N_{platforms} \cdot N_{SetsLightingPlat} \cdot LightingSystemCost1 \cdot ReductionFactorLighting \tag{39}$$

$$C_{3219} = N_{platforms} \cdot PlatformMonitoringCost + StructuralMonitoringCost \tag{40}$$

The mooring manufacturing cost (C_{33}) depends on the mooring lines engineering and project management (PM) cost (C_{331}), the tendon engineering and PM cost (if any) (C_{332}), the mooring lines manufacturing cost (C_{333}), the connector manufacturing cost (C_{334}), the chain stopper, fairlead manufacturing cost (C_{335}), the bending shoe fairlead, rotatory chain fairlead or similar cost (C_{336}), the mooring lines monitoring cost (C_{337}), the temporary buoys and/or other auxiliary components cost (C_{338}) and the tendon manufacturing and shipping cost (if any) (C_{339}):

$$C_{33} = C_{331} + C_{332} + C_{333} + C_{334} + C_{335} + C_{336} + C_{337} + C_{338} + C_{339} \quad (41)$$

The anchoring manufacturing cost (C_{34}) depends on the anchoring engineering and PM cost (C_{341}) and the anchor construction cost (C_{342}):

$$C_{34} = C_{341} + C_{342} \quad (42)$$

The electric system manufacturing cost (C_{35}) depends on the electric cable manufacturing cost (C_{351}) and the substation manufacturing cost (C_{352}):

$$C_{35} = C_{351} + C_{352} \quad (43)$$

Given the characteristics of offshore wind farms, related to the remote location from the coast, the installation of the components is an important part of its life cycle. In addition, several aspects related to the floating condition of the TLP platform must be considered to define an effective installation strategy from an economic point of view.

The costs of this phase are divided according to the elements of which an offshore wind farm is composed. In this sense, the installation costs (C_4) depend on generator installation costs (C_{41}), platforms installation costs (C_{42}), mooring and anchoring installation costs (C_{43}) and electric cable installation costs (C_{44}):

$$C_4 = C_{41} + C_{42} + C_{43} + C_{44} \quad (44)$$

The cost of installing the offshore wind turbines (C_{41}) is divided into the installation at port (C_{411}), the transport (C_{412}) and the installation offshore (C_{413}):

$$C_{41} = C_{411} + C_{412} + C_{413} \quad (45)$$

The cost of installing the floating TLP platforms (C_{42}) depends on the onshore commission cost (C_{421}), the offshore platform commissioning cost (C_{422}) and other costs-lifting equipment and miscellaneous costs (C_{423}):

$$C_{42} = C_{421} + C_{422} + C_{423} \quad (46)$$

The cost of installing the mooring and anchoring of the TLP platforms (C_{43}) depends on the anchor installation cost (C_{431}), the mooring line installation cost (C_{432}), the tendon installation cost (if any) (C_{433}) and other costs-miscellaneous (C_{434}):

$$C_{43} = \left(C_{abarge} + C_{atug} + C_{aaMOD} + C_{aapumpsanddivers}\right) \cdot \frac{N_{anchoring}}{T_{instbarge}} \quad (47)$$

The cost of installing the electric system (C_{44}) depends on the cost associated with the burial cable intertidal area for 1 platform (*BurialCableCost*1*Plat*), the cost associated with the HDD horizontal drilling for 1 platform (*HDDCost*1*Plat*), the cost associated with the dynamic cable installation for 1 platform (*DynamicCableInstallationCost*1*Plat*), the number of platforms (*Nplatforms*), the export cable installation cost (*ExportCableInstallationCost*), the cable mechanical protection cost (*CableMechanicalProtectionCost*), the cable burial (intertidal area) cost (*CableBurialIntertidalAreaCost*), the inter array cable commissioning cost (*InterarrayCableCommissioningCost*) and the export cable commissioning cost (*ExportCableCommissioningCost*):

$$\begin{aligned} C_{44} = \Big(N_{platforms} \cdot \; & (BurialCableCost1Plat + HDDCost1Plat \\ & + CableOnshoreCivilWorksCost1Plat)) \\ & + \Big(DynamicCableInstallationCost1Plat \cdot N_{platforms}\Big) \\ & + ExportCableInstallationCost + CableMechanicalProtectionCost \\ & + CableBurialIntertidalAreaCost + InterarrayCableCommissioningCost \\ & + ExportCableCommissioningCost \end{aligned} \tag{48}$$

The operation and maintenance costs are an important part of the life cycle of an offshore wind farm since it will be the most durable phase in time and in which many factors must be considered: the logistic capacity, distance to the coast, the reliability of the turbine components, etc.

Operation and maintenance costs (C_5) can be disaggregated into assurance costs (C_{51}), administration and operations cost (C_{52}), maintenance cost (C_{53}), onshore logistics (C_{54}) and offshore logistics (C_{55}). Materials, replacements, consumables and others are maintenance costs that must be considered. The costs of offshore logistics operations depend on the use of barges, marine cranes and helicopters:

$$C_5 = C_{51} + C_{52} + C_{53} + C_{54} + C_{55} \tag{49}$$

where:

$$C_{52} = C_{521} + C_{522} + C_{523} + C_{524} \tag{50}$$

$$C_{53} = C_{531} + C_{532} + C_{533} + C_{534} \tag{51}$$

$$C_{54} = N_{farm} \cdot C_{54year} \tag{52}$$

$$C_{55} = N_{farm} \cdot C_{55year} \tag{53}$$

where:

$$C_{55year} = C_{551year} + C_{552year} + C_{553year} + C_{554year} \tag{54}$$

Once the life of the components that make up the offshore wind farm has come to an end, the last phase of the life cycle begins the dismantling [44]. For this task, it is required to disconnect the mooring system. In addition, heavy decoupling operations of floating turbines must be carried out, as well as the transport of structures to the coast. Therefore, dismantling costs (C_6) depend on generator dismantling costs (C_{61}), the floating platform dismantling costs (C_{62}), mooring and anchoring dismantling costs (C_{63}) and electric systems dismantling costs (C_{64}):

$$C_6 = C_{61} + C_{62} + C_{63} + C_{64} \tag{55}$$

where:

$$C_{61} = PD_{turbine} \cdot (C_{41} + C_{42}) \tag{56}$$

$$C_{62} = 0 \tag{57}$$

$$C_{63} = PD_{mooring} \cdot C_{43} \tag{58}$$

$$C_{64} = PD_{cable} \cdot C_{44cable} + PD_{substation} \cdot C_{44sube} \tag{59}$$

3. Case Study

The CENTEC-TLP is composed of lower pontoons that help to stabilize the transport phase and act as the primary buoyancy bodies in the installed form (see Figure 1). The overall width of the platform is 49.5 m, with a draft of 20 m when installed. During the towing phase, the draft lowers to 3.85 m, making it possible to place the platform into the water in most ports without being concerned with port-side draft limitations. The structural integrity is provided by the support braces. It uses 3 mooring lines per corner. Detailed sizing information of the platform is available in [25].

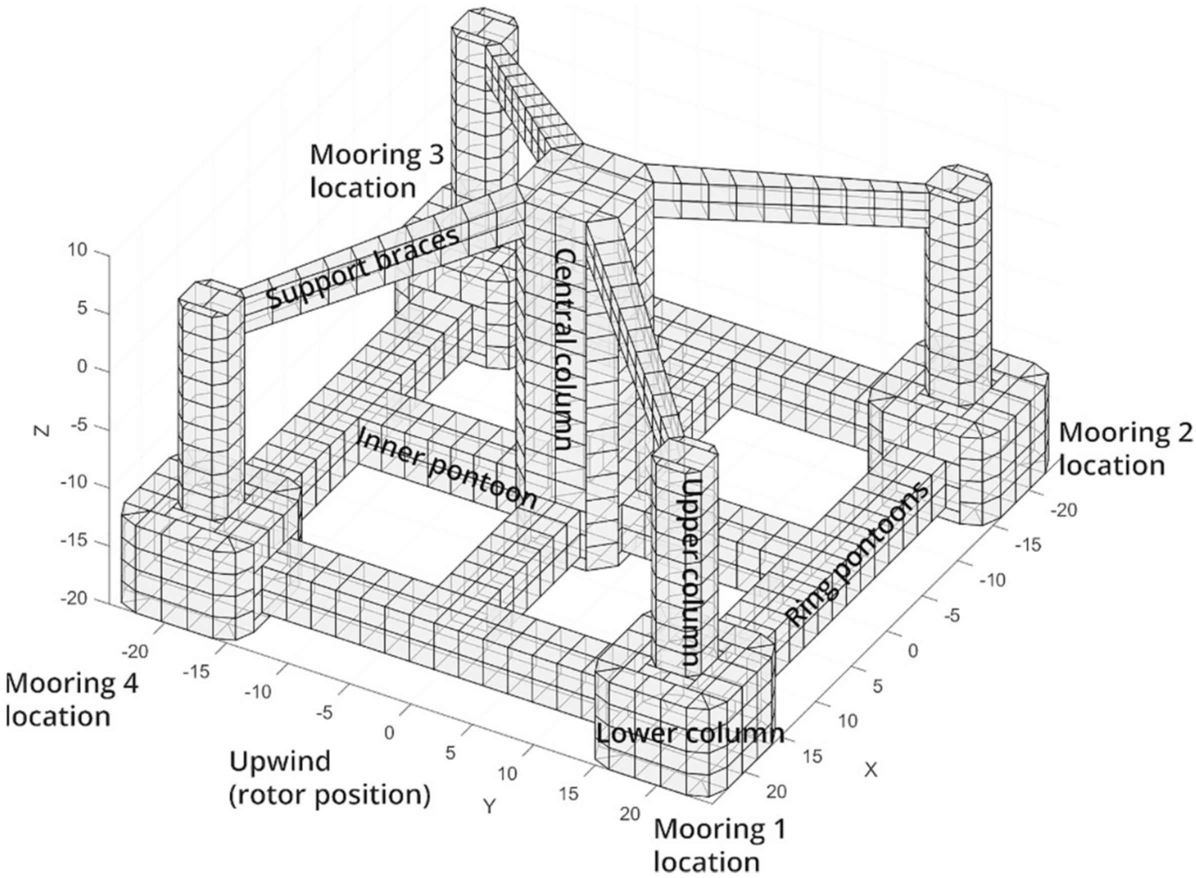

Figure 1. Hull form of CENTEC—TLP.

Regarding the offshore wind turbine, the DTU 10 MW Reference Wind Turbine has been selected. Its main characteristics are: 10 MW of rated power, 4 m/s cut in wind speed, 25 m/s cut out wind speed, 11.4 m/s rated wind speed, 3 blades, 178.3 m rotor diameter, 5.6 m hub diameter and 119 m hub height.

An objective of the Arcwind project is to identify optimal locations for floating wind projects in the European Atlantic region promising offshore wind development area, as identified in previous studies [45–48] Nine locations have been defined in the Spanish coastal area and further known constraints have been identified, the locations selection methodology is presented and discussed by Díaz and Guedes Soares [49].

These nine locations are subsequently ranked using an in-house evaluation modelling tool against several criteria to establish the optimum location within Spain. The main characteristics of the Ribadeo location are shown in Table 2.

Table 2. Main characteristics of the Ribadeo floating wind farm.

Item	Value	Units
Water depth	150	m/s
Wave conditions	2.15	m
Marine currents	0.51	m/s
Distance to local electrical grid	18.60	km
Distance from coastal facilities	89.50	km
Distance from shore	17.61	km
Distance from maritime routes	1.50	km
Distance from protected areas	10.92	km
Area of the territory	405	km^2
Wind farm capacity	880	MW
Number of 10 MW turbines	88	-

The nine zones identified during the site selection study [49] as most suitable for the development of commercial-scale floating wind farms, were pragmatically characterized for their compliance with a set of defined technical and environmental parameters. The key constraints considered immovable for offshore wind farm development were as follows; offshore wind resource, the Exclusive Economic Zone (EEZ), water depths, proximity to other maritime activities and distance to environmental protected areas. Further constraints were also considered within the analysis, such as the proximity to underwater lines, proximity to maritime routes, visual impact, distance to the electrical grid and wave conditions. Due to the significant level of constraints considered, exclusion zones were established. This approach considers the main factors that prevent the sustainable deployment of a floating wind farm within the European waters guaranteeing the viability of the achieved locations.

The resultant areas after applying the exclusion criteria cover 1275 km^2 of the total area evaluated necessitating a secondary assessment of these areas based on the proposed evaluation criteria. Therefore, the entire space proposed would suppose a total installation of around 500 floating wind turbines. Figure 2 identifies some of the restrictions involved in the process of location identification. It shows the identified nine locations based on the site selection assessment.

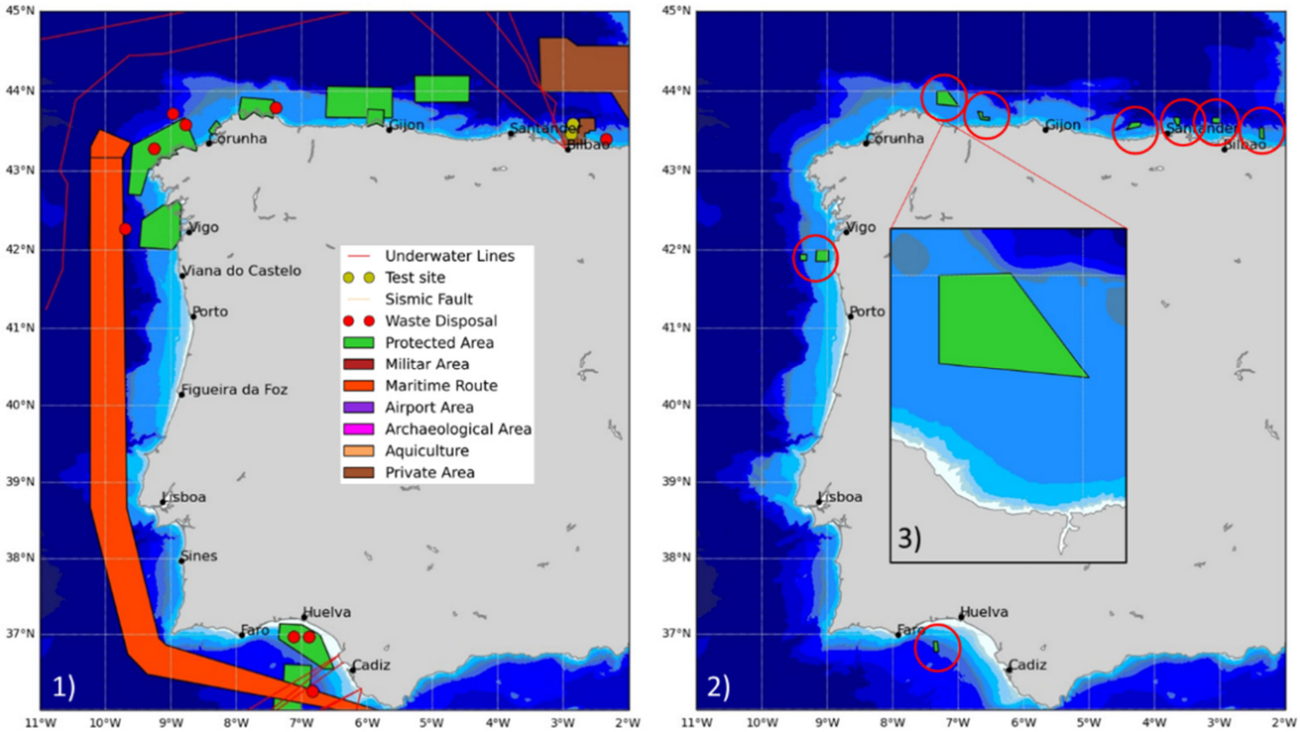

Figure 2. Floating wind map in Spain. (1) Some restrictions present in Spanish waters. (2) Floating wind farm proposed. (3) Ribadeo floating wind farm.

The best location within Spain's EEZ was selected using multicriteria decision-making techniques that ranked the floating wind farm areas proposed based on criteria and experts' opinions [50–52]. Applying these assumptions to the nine locations, the Ribadeo location was identified as the most suitable for the installation of floating turbines. Figures 1–3 visualize this area.

This study is focused on the technical and economic feasibility of the CENTEC-TLP concept for the Ribadeo location (see Figure 2). Ribadeo is located on the Galician Coast, Northwest of Spain (latitude, longitude: 43.837, −7.326). The wind farm location is characterized by an average wind velocity of 9.3 m/s and wind potential of 4923 h/yr. Moreover, other details that show the huge potential of the area are presented in Table 1. Figure 2 shows three maps: (1) the map of restrictions to install offshore wind farms in Spanish waters;

(2) the floating offshore wind farms proposed (in green); and (3) the Ribadeo floating offshore wind farm, which is the final location selected for this study.

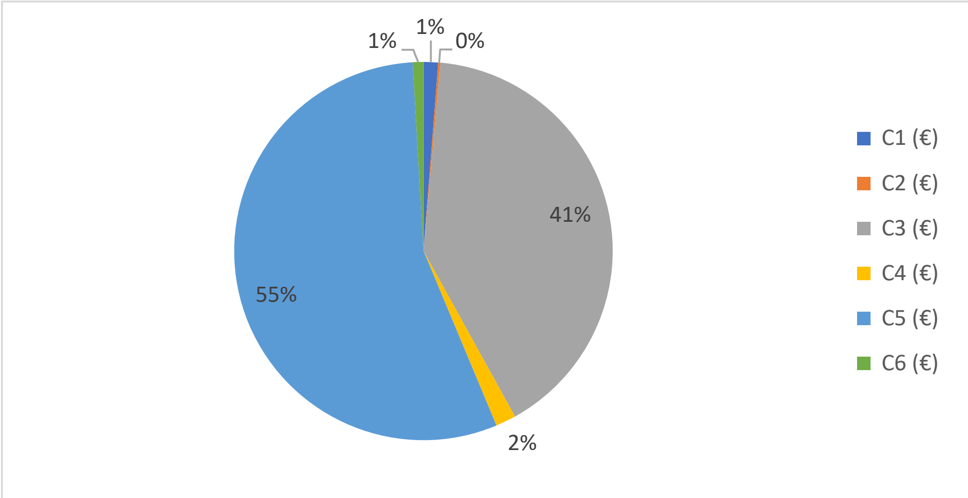

Figure 3. Total cost results. Being C1 (conception and definition cost), C2 (design and development cost), C3 (manufacturing cost), C4 (installation cost), C5 (exploitation cost) and C6 (dismantling cost).

Several scenarios were considered in the present case study for the different locations of the farms. These scenarios were defined considering three electric tariffs (50 €/MWh, 100 €/MWh and 150 €/MWh), due to the permanent change in the electric rates in Europe during the last months [53], and three capital costs (6%, 8% and 10%) [54].

The initial variables are shown in Table 3.

Table 3. Main variables.

Variable	Value	Units
EPCIC	0	%
OffshoreSiteR	100,000	€
Nplatforms	88	platforms
C_{emet}	2,338,480	€
C_{smet}	467,696	€
C_{samet}	116,924	€
EvaluationReportCost	2500	€/MW
TurbineP	10	MW
GeophysicalDailyCost	15,000	€/day
GeophysicalDays	2	days
GeotechnicalDailyCost	35,000	€/day
GeotechnicalDays	3	days
$C_{insurance}$	33,877.2	€/MW
TravellingCosts	0.15	-
Staff	15	staff
AverageCostY	65,000	€/year
Years0	7	years
OfficeRentingM	4000	€/month
RatioWTGPriceCosts	-	-
Nplatforms	88	platforms
FEED	3,877,520	€
DetailDesignCosts	5,028,000	€
TankTestingInplace	125,000	€
TankTestingTransport	75,000	€
PreliminaryWorksYardCosts	5,000,000	€
OneDrydockCost	3,550,000	€

Table 3. *Cont.*

Variable	Value	Units
$N_{drydocks}$	1	docks
C_{3241}	17,104,140.9	€
C_{3242}	82,125	€
C_{3243}	54,750	€
C_{3244}	862,312.5	€
$PreparingSeabedCost$	200,000	€
$TotalMaterialCostPlatform$	312,052,35	€
$CraneDrydockConstructionCostYT$	2,940,000	€
$CraneDrydockSupportCostYT$	1,900,000	€
$HarbourInternalTowingYears$	2	years
$TugMobDemobCost$	3000	€
$BollarPullTugDR$	18,000	€/day
$N_{DiversPlat}$	2	divers
$DiverDailyCost$	1500	€/day
$DiverDaysIntervention$	2	days
$N_{AccessesPlat}$	1	-
$PlatformAccessCost$	175,000	€/platform
$N_{InternalsTower}$	1	-
$TowerInternalsCost$	125,000	€/platform
$N_{JTubesPlat}$	1	j-tubes
$JTubeCost$	40,000	€/j-tube
$ReductionFactorBallast$	0.8	-
$TotalBallastCostPlat$	0	€
$N\_SetsCommunicationPlat$	1	-
$ReductionFactorCommunication$	75,000	€
$CommunicationSystemCost1$	0.8	-
$N_{SetsLightingPlat}$	1	-
$LightingSystemCost1$	20,000	€
$ReductionFactorLighting$	0.8	-
$PlatformMonitoringCost$	20.000	€/platform
$StructuralMonitoringCost$	90.000	€
$C_{33} + C_{34}$	268,712,67	€
C_{351}	60,901,417	€
C_{352}	15,000.000	€
C_{411}	132,285	€
C_{412}	7,002,858.21	€
C_{413}	14,744,889	€
C_{42}	12,414,616	€
C_{abarge}	7500	€/day
C_{atug}	22,502	€/day
C_{aaMOD}	5656	€/day
$C_{aapumpsanddivers}$	0	€/day
$N_{anchoring}$	1056	anchors
$T_{instbarge}$	3	Anchors/day
$BurialCableCost1Plat$	25,000	€/platform
$HDDCost1Plat$	0	€/platform
$DynamicCableInstallationCost1Plat$	100,000	€/platform
$ExportCableInstallationCost$	8,000,000	€
$CableMechanicalProtectionCost$	80,000	€
$CableBurialIntertidalAreaCost$	1,000,000	€
$InterarrayCableCommissioningCost$	100,000	€
$ExportCableCommissioningCost$	100,000	€
C_{51}	22,618,239	€
C_{521}	6,750,000	€
C_{522}	33,000,000	€
C_{523}	3,575,000	€
C_{524}	19,250,000	€
C_{531}	630,300	€

Table 3. *Cont.*

Variable	Value	Units
C_{532}	16,654,000	€
C_{533}	19,250,000	€
C_{534}	115,500,000	€
N_{farm}	25	Years
C_{54year}	1,210,000	€/year
$C_{551year}$	5,500,000	€/year
$C_{552year}$	4,950,000	€/year
$C_{553year}$	17,600,000	€/year
$C_{554year}$	33,000,000	€/year
$PD_{turbine}$	70%	-
$PD_{mooring}$	90%	-
PD_{cable}	10%	-
$PD_{substation}$	90%	-

4. Results

4.1. Technical Overview

The technical validation of CENTEC-TLP was carried out both numerically and experimentally. This section summarises the previous publications discussing the performance of the TLP before proceeding with the economics. The towing dynamics are explained in [26]. It was tested experimentally in waves up to 3 m of significant wave height with speeds up to 5 knots. The motions of the platform under these scenarios show that the pitching angle is limited to 0.7 degrees. Given that the platform has stability up to 10 degrees, its motion dynamics allow a large weather window to tow it to the location. Without the platform motions being a limiting factor, other concerns such as the installation process and the owing performance of the tugboats gain prevalence. The platform also has low wave resistance, allowing it to be towed using lower-powered tugboats.

After the platform is towed and installed, the primary factor for tension leg platforms is the mooring line tensions. The dynamics explained in [55] show that the platform can withstand the 50-year extreme weather in the selected installation area as well as the below and above rated operational conditions. As the structure is a TLP, its pitching angles are limited to values under a unit degree. Hence, it is not affected by the platform pitch related power production issues as explained in [56]. The verification of both the towing and motion performance leaves the platform's economic feasibility as the deciding factor, which is detailed in the following sections.

4.2. Economic Results

Regarding the total costs of the farm (see Figure 3), the farm has a C1 of EUR 54.16 M, a C2 of EUR 8.23 M, a C3 of EUR 1769.83 M, a C4 of EUR 74.85 M a C5 of EUR 2419.85 M and a C6 of EUR 39.51 M. They represent the 1.2% of C1, the 0.2% of C2, the 40.5% of C3, the 1.7% of C4, the 55.4% of C5 and the 0.9% of C6.

Regarding LCOE (see Figure 4), this case study gives values of EUR 76.67/MWh, EUR 71.71/MWh and EUR 67.03/MWh for an electric tariff of EUR 150/MWh and 10, 8 and 6% of capital cost respectively. In addition, it gives values of EUR 62.77/MWh, EUR 58.42/MWh and EUR 54.33/MWh for an electric tariff of EUR 100/MWh and 10, 8 and 6% of capital cost respectively. finally, it gives values of EUR 80.08/MWh, EUR 73.89/MWh and EUR 68.11/MWh for an electric tariff of EUR 50/MWh and 10, 8 and 6% respectively.

The LCOE usually does not depend on the electric tariff considered. However, in the present model, it depends indirectly because the LCOE has been calculated considering the WACC (weighted average cost of capital), which depends directly on the own resources of the enterprise. These own resources have been calculated considering the total initial investment (C1, C2, C3, C4 and C6) and the investment in working capital. Particularly, the investment in working capital has been calculated considering an investment of two months of the incomes of the project (tariff*energy produced), which makes the LCOE depend indirectly on the electricity tariff.

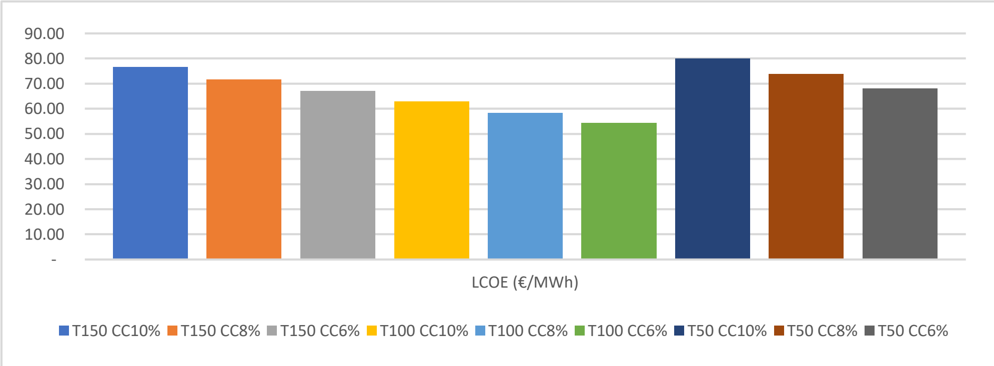

Figure 4. LCOE results.

Regarding *NPV* (see Figure 5), this case study gives values of EUR 1800.44 M, EUR 2180.77 M and EUR 2636.45 M for an electric tariff of EUR 150/MWh and 10, 8 and 6% of capital cost respectively. In addition, it gives values of EUR 258.33 M, EUR 330.86 M and EUR 418.11 M for an electric tariff of EUR 100/MWh and 10, 8 and 6% of capital cost respectively. Finally, it gives values of EUR −898.35 M, EUR −849.96 M and EUR −782.90 M for an electric tariff of EUR 50/MWh and 10, 8 and 6% respectively. As it is observed, a higher capital cost gives values of *NPV* lower. Therefore, the farm will be economically feasible in terms of *NPV* for a tariff of EUR 150/MWh and a tariff of EUR 100/MWh, because its value is higher than 0.

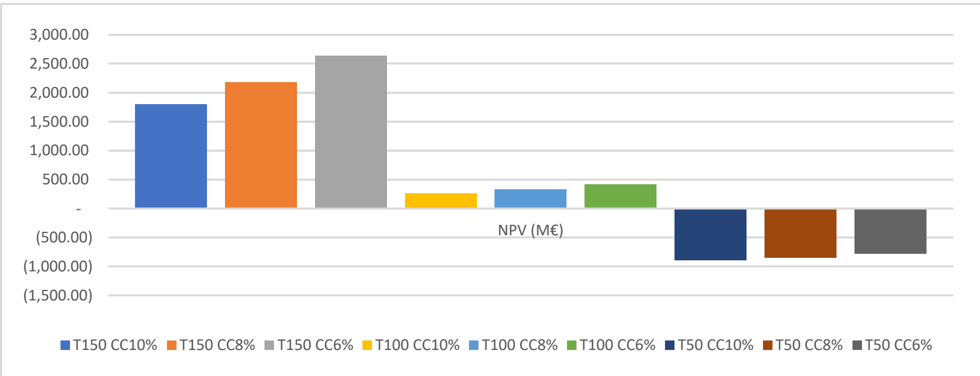

Figure 5. *NPV* results.

Regarding *IRR* (see Figure 6), this case study gives values of 14.74% for an electric tariff of EUR 150/MWh, 11.25% for an electric tariff of EUR 100/MWh and 0.44% for an electric tariff of EUR 50/MWh, being its value independent on the capital cost considered. Therefore, the farm will be economically feasible in terms of *IRR* for a tariff of EUR 150/MWh and a tariff of EUR 100/MWh, because its value is higher than the WACC considered.

Regarding DPBP (see Figure 7), this case study gives values of 9 years, 9 years and 8 years for an electric tariff of EUR 150/MWh and 10, 8 and 6% of capital cost respectively. In addition, it gives values of 13 years, 13 years and 12 years for an electric tariff of EUR 100/MWh and 10, 8 and 6% of capital cost respectively. Finally, it gives values of 28 years for all the capital costs considered (10, 8 and 6%). As is observed, a higher electric tariff gives values of DPBP lower. Therefore, the farm will be economically feasible in terms of DPBP for a tariff of EUR 150/MWh and for a tariff of EUR 100/MWh, because its values (from 8 to 13 years) are lower than the life cycle of the project (25 years).

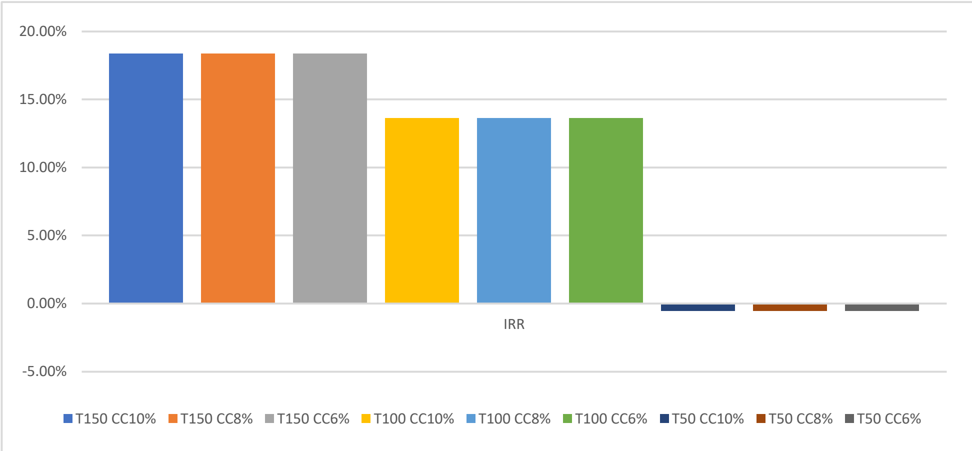

Figure 6. *IRR* results.

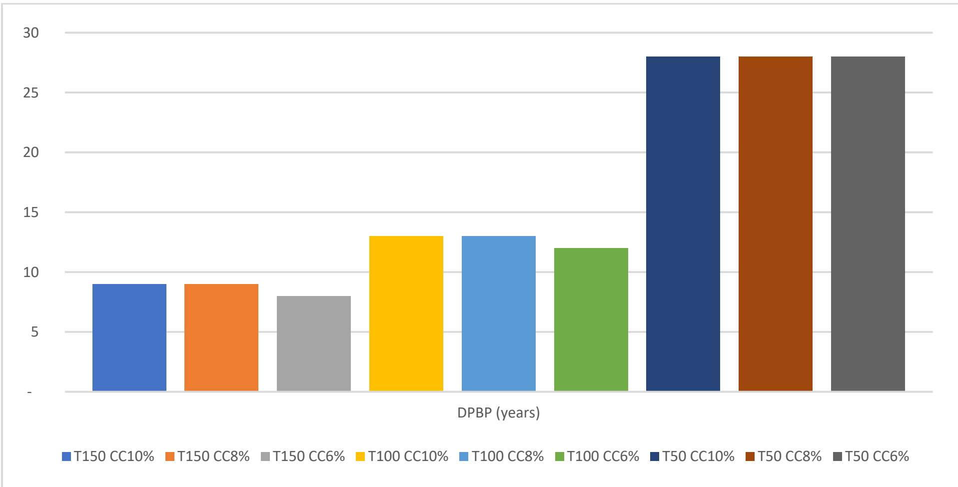

Figure 7. DPBP results.

5. Discussion

This work has described the methodology for calculating the economic feasibility of a floating offshore wind farm composed of TLP platforms. For this purpose, firstly the life-cycle costs have been analysed. In this context, the costs have been divided into the costs of each life-cycle stage of the process: conception and definition cost, design and development cost, manufacturing cost, installation cost, exploitation cost and dismantling cost.

Secondly, the main economic feasibility indicators have been calculated taking into account the cash flows of the project: internal rate of return (*IRR*), net present value (*NPV*), discounted pay-back period (PBP) and levelized cost of energy (LCOE).

The case study analysed is based on the TLP platform designed by the CENTEC. One farm of 880 MW has been considered for this platform located along the Atlantic Coast of the European Union. It has been located in Ribadeo (the North Area of the North-West region of Galicia, in Spain). Eighteen case studies have been analysed considering different scenarios in terms of three different electric tariffs and three different costs of capital.

Results indicate how important is the electric tariff to determine the values of *IRR*, *NPV* and DPBP. The best result is obtained for an electric tariff of EUR 150/MWh and a cost of capital of 6%. It has values of 18.34% of *IRR*, EUR 2636.45 M of *NPV* and 8 years of DPBP. Regarding their values of LCOE, the farm has a minimum value of EUR 54.33/MWh. It makes the platform economically feasible for the location selected because the internal rate of return is higher than the capital cost, the net present value is higher than zero and the discounted pay-back period is lower than the life cycle of the project.

The values of LCOE are similar to other authors, which go from GBP 49.28/MWh to GBP 72.74/MWh for the minimum values of Anastasia Ioannou et al. [57] or which go from USD 60/MWh to USD 110/MWh for Maira Bruck et al. [58], for instance.

The method proposed is important to help all the stakeholders (investors, facilities, enterprises, etc.) to do deep analysis in economic terms of the TLP platform selected.

Author Contributions: Conceptualization, A.F.-V., D.C.I., F.P.-G., I.L.-G., A.I.G.-D. and L.C.-S.; Investigation, A.F.-V., D.C.I., L.C.-S., E.U., H.D.; Methodology, A.F.-V., D.C.I., L.C.-S., E.U., H.D.; Resources, A.F.-V., D.C.I., L.C.-S., E.U., H.D.; Supervision, C.G.S.; Writing—original draft, A.F.-V., L.C.-S., D.C.I., F.P.-G., I.L.-G., A.I.G.-D., E.U., H.D., C.G.S.; Writing—review & editing, C.G.S. All authors have read and agreed to the published version of the manuscript.

Funding: This research was funded by EAPA_344/2016 ARCWIND project, co-financed by the European Regional Development Fund through the Interreg Atlantic Area Programme. This work contributes to the Strategic Research Plan of the Centre for Marine Technology and Ocean Engineering (CENTEC), which is financed by the Portuguese Foundation for Science and Technology (Fundação para a Ciência e Tecnologia—FCT) under contract UIDB/UIDP/00134/2020.

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Data Availability Statement: Not applicable.

Conflicts of Interest: The authors declare no conflict of interest.

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