60MW Multi-Rotor Vertical Axis Wind Turbine

Midterm report

Group 21

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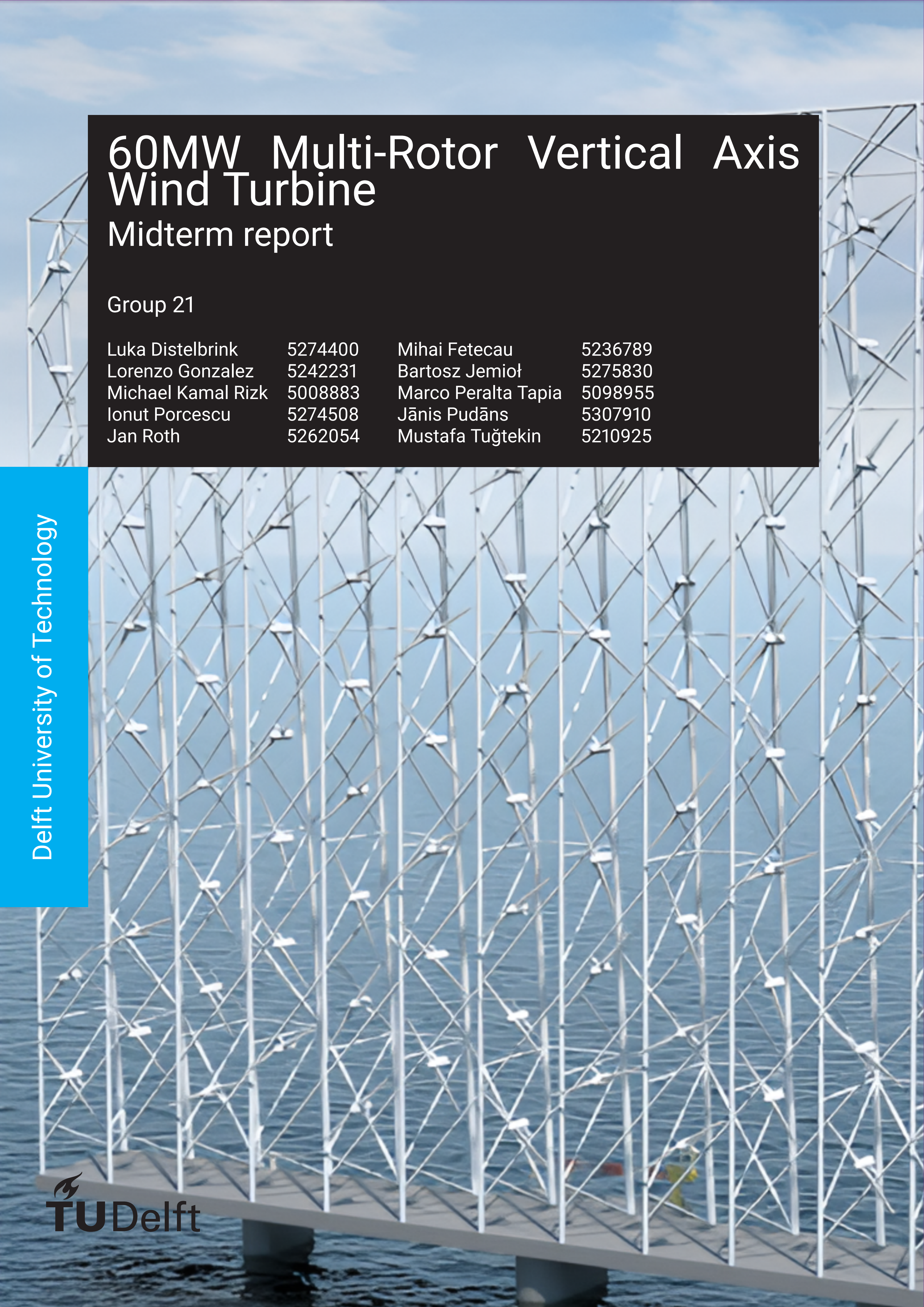

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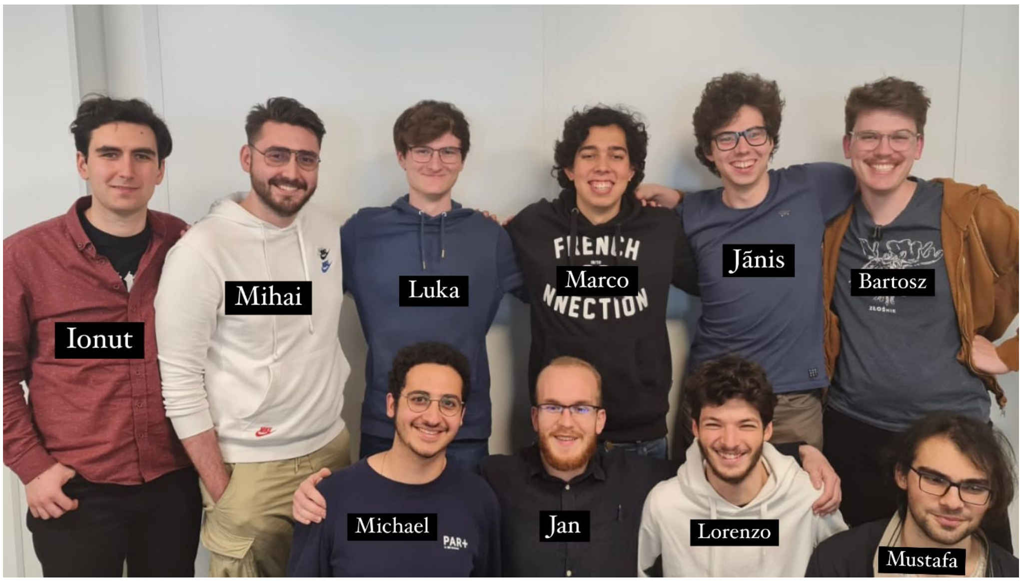

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Course: AE3200 Design Synthesis

Executive Overview

This report begins with an updated organizational overview in Chapter 1. This includes an updated work flow diagram and updated work flow structure. A Gantt chart follows these and all together serve as guides for work organization for the following five weeks of design.

The report focuses on the analysis of design options at the subsystem level in Chapter 2. When there is a trade-off to be done between different options for these subsystems, all options are analyzed, with the results used in Chapter 3, where the trade-off between is made.

The trade-off is followed by a discussion of the operations and logistics for the conceptual design in Chapter 4. This chapter details the operation strategy, maintenance strategy, and logistics strategy, at a level appropriate for the conceptual design stage. This concludes the design part of the report, with Chapter 5 discussing verification and validation of tools that were used for the design process so far. With many of the models used at this point being semi-empirical, a large part just involves performing sensitivity analysis.

The report then goes on to detail the chosen conceptual design to take to the preliminary design part in Chapter 6. This design is the result of analysis performed in Chapter 2 and trade-offs in Chapter 3. This is followed by Chapter 7, which analyzes the technical risks identified during the conceptual design stage. This includes identification, assessment, map, and the plan for their management. For the design option, the performance analysis with regard to user requirements is presented in Chapter 8. This focuses specifically on LCoE, expanding on the work done in the Baseline Report, and providing a more detailed look at the cost savings. Lastly, the sustainability strategy for the design is presented in Chapter 9, with a focus on the environmental effects the system will have.

Organization

To help with organization of the work, the work breakdown structure was made for the design process. The design process tasks were broken down to up to three levels, when it was already possible. The breakdown was not done down to the same task size, as some details are not yet known. With the work breakdown structure, the tasks were ordered in chronological order in order to make the work flow diagram. This was not done for all groups of tasks, as some groups had very little interdependence.

Along with WBS and WFD, the division of work responsibilities was devised. The tasks in WBS were assigned to one of the eleven categories, based on the knowledge and work required to complete them. Between two to four people were then assigned to each. This will hopefully allow for more efficient work in the group, as responsibilities seem to be clearly defined.

Subsystem Analysis

To break up the design into smaller parts, the subsystems of the turbine were defined. The used subsystems are Tower (TWR), Yaw control (YCT), Power control(PCT), Wake control (WCT), Drive Train (DRT), Rotor (RTR), and Operation control (OCT). The interactions between these subsystems were recorded in an N2-chart. After this, the design options to be traded off were presented, and initial estimations were made for characteristics that are used in the trade-off.

Initial estimations include the generator mass, and loads on the foundation. The total generator mass was assumed to be proportional to the torque in the drive shaft and its power proportional to cross-sectional area. The total generator mass was proportional to the reciprocal of the tip speed ratio times the number of generators in a row $M \propto \frac{1}{\lambda n}$. This result is true for all design options considered. The loads on the foundation were determined based on weight of the structure, the drag of the structure and the loads on the wing mounted on the structure as the wake management system. The loads on the foundation are then used to size the monopile and the floating foundation.

To get a mass and cost estimation of the floater, a scaling method proposed by Wu and Kim is used.

This method up-scales the OC4 DeepCwind floater by scaling the radius of the buoyant columns, and the distance between them, while keeping the draft of the floater constant [1]. Using this method a semi-submersible floater was designed that has a metal mass of 9742 tonnes, with 37 186 tonnes of ballast water, and a static pitch angle of 5°

For the monopile bending, normal force and torsion was considered. The loads on the structure driving the monopile sizing where bending, normal force and wave loads on the structure. For the monopile area a hollow cylinder with constant thickness was assumed which would counteract the forces. The length of the monopile was assumed to 67 m. The resultant mass of the monopile is 5513 t with a diameter of 9 m and a thickness of 0.2 m.

For the number of rotors, the total power of the wind turbine was kept the same so that all design options comply with the 60MW requirement . In addition to this the power of the rotors was related to the performance coefficient and wind velocity in order simplify the comparison of design option by keeping the cp the same.

Design Trade-Off

This section concerned a total of six trade-offs that were made between the possible options to be used for the design. The first trade-off was made between the usage of **h**orizontal **a**xis **w**ind **t**urbines (HAWTs) and the **v**ertical **a**xis **w**ind **t**urbines (VAWTs) for the multi-rotor design option. The trade-off resulted going in favor VAWT, mainly due to much easier maintainability as well as making the structural design easier.

The next trade-off which was performed was between the solid foundation (monopile) and a floating foundation (using a pontoon/floater). The choice of using a solid foundation was made mainly due to the shallow depth for which the system was designed making this option much lighter and simpler. Should the design need to be installed in much deeper water, this decision may need to be revised.

Drive train trade-off was performed next, having to select between four different generator types: DD-PMS generator, EES generator, DFI generator and a gearbox PMS generator. Due to is low use of rare-earth metals the trade-off ended in favor of three-stage geared double-fed induction generator over a permanent magnet option. This was one of more important trade-offs when it comes to maintenance and sustainability, as generators account for a large part of maintenance costs and rare-earth consumption.

Yaw control system was done after that. The choice was to be made between using aerodynamic, electric, hydraulic, or some combination of these for yaw control of the structure. With the main advantage of aerodynamics being simplicity and the main advantage of electric responsiveness, a combination of both was decided as offering the best reliability at low operational costs.

The last trade-off was involving the rotor size and determining the rotor count. The trade off was between designs of one rotor per shaft, two rotors per shaft and three rotors per shaft. The trade-off criteria focused on the differences in cost, maintenance, reliability and mass with the different design options. The trade off determined that the option with two rotors per shaft is the most feasible. A sensitivity analysis showed that ignoring manufacturing criteria, the single rotor per shaft design was also feasible

Operations and Logistics Concept

Operations strategy detailed in the report details installation and decommissioning procedures. These are relatively symmetric, roughly divided in installation of foundation and monopile, followed by the tower assembly, and installation of the remaining systems on the frame. Besides installation and decommissioning, nominal operation is also considered; main concern comes from maintenance and inspection during operation.

Maintenance strategy section discussed different approaches to maintenance which could be employed, along with listing the sensors HAWTs typically use to monitor health of the system. Four strategies were discussed: corrective, preventive, conditions-base, and predictive. Out of the four, applying predictive maintenance strategy seem to be the best choice, as it promises to reduce operating costs and downtime the most, at the expense of requiring more sensors and inspection. The section then went further into detail about specific inspections and sensors would be needed by individual subsystems.

Lastly, logistics strategy detailed storage, transport, and accessibility. For storage of parts, typical strategy is to store some on wind farm depot. Since the design features a large base plate, some smaller parts could also be stored there. For transport to and from the site, involves using either ships or helicopters, which are typically in use.

Verification and Validation

To verify the model used to calculate the dimensions of the monopile, a sensitivity analysis was performed, which confirmed that the calculated bending stress, monopile diameter, and thickness vary with increased applied loads as expected. In addition to this, for validation, the model was compared to empirical relations found in the literature. In general, the model did not coincide with the empirical estimations, but for the dimensions and loads considered for the design, they were close enough to be valid for this stage of design.

The model calculating floater dimensions was verified by comparing the calculated figures for 10 MW and 15 MW turbine floaters, with those found in the source paper by Wu and Kim that proposed the sizing method. The relative errors were smaller than 4 % which is accurate enough for this stage of design. The scaling model was already validated by Wu and Kim by comparing results to the 15 MW UMaine VolturnUS-S floater [1].

Conceptual Design

The conceptual design involved summarizing the outcomes design decisions in Chapter 2 and Chapter 3. This led to a design that will be carried from the conceptual stage to the preliminary stage. The design is expected to have a truss structure tower with a height of 280 m, width of 530 m, and depth of about 65 m. The truss structure is to be mounted on a steel monopile with the diameter 9 m.

For both the underwater and above-water structures a steel alloy will be used. The specific type is not selected yet, but the main drivers will be the loading conditions, corrosion environment, and sustainability. For the blades, another trade-off will have to be performed between composite and steel or other metal alloys. Key criteria will be the sustainability, loading, and fatigue characteristics.

With regards to aerodynamic characteristics, the turbine is assumed to be H type with a maximum power coefficient of $C_{p_{\max}} = 0.47$ and the maximum thrust coefficient of $C_{T_{\max}} = 0.5$, with a tip speed ratio of $\lambda = 4.5$. This would require pitch control and optimized design. In order to satisfy performance needs, it is expected that the blades will likely need active stall control. For the wake recovery, the system is expected to use an HLD mounted on the top of the turbine. This is again something that will have to be further considered at the following stages of design.

Control of the system concerns both yawing and power control. In order to protect against structural damage, the system has to apply brakes to the rotors at wind speed above the specified limit. Bellow that speed, the system will have to use active pitch control. This would allow it to reach higher efficiency and speed control. This could be paired with DFIG's capability of using torque for breaking. Excess and reserve power is expected to be stored in some other form in order to save some for emergency situations.

In order to yaw, the system is to use an aerodynamic method for yaw control, involving differential drag. This would involve changing the rotor's speed and pitch in order to cause asymmetric loads, which would yaw the structure. In order to allow operation in cases where turbines may need to be parked or are broken, a backup electric yaw motor should also be installed.

Technical Risk Assessment

A technical risk assessment was performed on the conceptual design. This involved identifying the technical performance, cost, scheduling, sustainability and programmatic risks. The technical performance risks were further divided into subsystem risks. The largest identified risks included lightning strikes, harm to surrounding ecosystems in the form of pile driving noise or bird collisions, corrosion due to the saline environment, and failures of certain critical components such as the yaw bearing and shaft brakes.

For each of these high risks, mitigation measures were identified to reduce the likelihood or consequences, resulting in a new post mitigation risk matrix. Lightning remained as a relatively high risk even after the mitigation procedures, so a contingency strategy involving manned inspections and maintenance after thunderstorms was proposed.

Performance Analysis

The performance analysis is solely based on the levelized cost of electricity. The reason for choosing the LCoE as the main performance indicator was the fact it incorporate all the performance figures, energy production, power density, ongoing and upfront costs, in one easy to compare number. The goal for the LCoE has been set to 30€/MWh, which is a 45% reduction compared to the projection done by WindEurope [2]. The cost analysis showed that with the anticipated changes in costs, the proposed design is capable of achieving the set targets. The analysis also showed that the design successfully de-emphasizes the cost impact of maintenance and high-cost turbine components, including generators, gearboxes, and rotors.

Sustainability Strategy

The spatial requirements of offshore wind energy generation are expected to grow exponentially in the coming years. As the space available for wind farms is limited, the power density of a wind turbine type is an important figure for sustainability, as a higher density means that a larger amount of wind energy can be generated. The proposed MRS-VAWT is expected to achieve a power density of 15 MW/km^2, which is a significant increase from the most power-dense systems currently in use at around 5 MW/km^2[3].

The choice of material for the wind turbine has the largest impact on the equivalent $CO2_{eq}$ emissions [4] [5]. To reduce this, recyclable materials such as steel alloy will be considered for the rotor blades. In addition to this, materials should be sourced and manufactured locally as much as possible. DFIG generators with a three-stage gearbox will be used to avoid the use of rare-earth metals.

During operation, a significant fraction of the GHG emissions results from using specialized vessels to replace large components. By using the MRS concept, individual components can be smaller, reducing the need for specialized and large vehicles. Another large percentage of GHG emissions comes from producing and decommissioning lubricants and spare parts. Emissions can be reduced by reducing the likelihood of the most common failure types, mainly for the blade, shaft, gearbox, and generator. Failure rates for the gearbox, generator, and shaft may be reduced by overdesigning them, which is made possible by placing the generator and gearbox at the bottom of the MRS structure. The failure rate of the blade is reduced because of the lower tip speed ratio of the VAWTs.

Turbine repowering and life extension are explored as end-of-life options. These reduce the $CO_{2_{eq}}$ emissions of the turbine. The additional modularity of the MRS design may further reduce the emissions of these operations, as the need for High Lifting Vehicles can be reduced with smaller individual components, and with the heavy drive train parts located at the bottom of the structure.

Once the turbine is finally decommissioned it must be recycled. The main recyclability concern with conventional turbines is the composite blades. As the VAWTs have a lower TSR, and are smaller than state-of-the-art conventional turbines, using recyclable metal rotor blades is feasible.

Contents

1 Organisation 1
1.1 Introduction . . . 1
1.2 Work Breakdown Structure and Work Flow Diagram . . . 1
1.3 Team organisation . . . 2
2 Subsystem Analysis 7
2.1 Subsystem definition. . . . 7
2.2 Subsystem interfaces. . . . 8
2.3 Design option trees. . . . 9
2.4 Design options considerations . . . 10
2.5 Rotor number. . . . 17
3 Design Trade-Off 18
3.1 Trade-off organisation . . . 18
3.2 Rotor orientation trade-off . . . 18
3.3 Yaw control trade-off. . . . 21
3.4 Rotor sizing trade-off. . . . 24
3.5 Foundation trade-off. . . . 28
3.6 Drive train trade-off . . . 30
4 Operation and Logistics Concept 34
4.1 Operation strategy . . . 34
4.2 Maintenance strategy . . . 35
4.3 Logistics strategy . . . 37
5 Verification and Validation 39
5.1 Verification for monopile . . . 39
5.2 Verification of floater model. . . . 40
5.3 Validation of monopile model. . . . 41
5.4 Validation of floater model . . . 43
6 Conceptual Design 44
6.1 Structural characteristics . . . 44
6.2 Material characteristics . . . 45
6.3 Aerodynamic characteristics . . . 46
6.4 Pitch control . . . 47
6.5 Power storage and control . . . 48
6.6 Yaw control . . . 49
7 Technical Risk Assessment 50
7.1 Risk identification . . . 50
7.2 Risk management . . . 51
8 Performance Analysis 54
8.1 Levelized cost of electricity for convectional Designs . . . 54
8.2 Description of the cost model . . . 54
8.3 Cost impact of the proposed design . . . 55
8.4 Conclusion from the cost model . . . 58
9 Sustainability Strategy 59
9.1 Sustainability contributions . . . 59
9.2 Materials and manufacturing . . . 59
9.3 Operations . . . 60
9.4 End of life . . . 61
9.5 Ecological impact . . . 62
10 Conclusion 63
Bibliography 64

1 Organisation

1.1. Introduction

In the last 20 years, the demand for sustainable energy has been considerably increasing, primarily due to the effects that climate change and global warming are having on the world. Wind energy is one of the most sustainable ways of generating electricity, as power is extracted directly by air, and no toxic emissions are produced. Furthermore, both onshore and offshore wind turbines result in being highly cost-effective for generating electricity. The main disadvantage of this technology is that the best way of increasing the amount of energy produced is by scaling up the entire structure. Consequently, when this happens, the number of units per megawatt decreases considerably, leading to less complex infrastructure and lower maintenance costs. Additionally, multi-rotor structures, consisting of multiple rotors operating in parallel, can maximise the advantages of upscaling and achieve greater unit capacities compared to traditional three-blade HAWT. Combining multi-rotor turbines with Vertical Axis Wind Turbines (VAWT) can obtain even higher performance gains at the turbine and wind farm levels.

With this background information in mind, the goal of this project is to undertake a ten-week exercise focused on the conceptual design of a multi-rotor VAWT. The following report aims to describe the preliminary analysis and design activities the group performed, leading to the selected concept entering the detailed design phase. The mentioned paper can be seen as a continuation of the Baseline report [6] in which crucial elements such as subsystem requirements and preliminary design options were presented.

The report is structured as follows. The first chapter is entirely dedicated to the organisational aspect of the project. This chapter presents diagrams such as Workflow diagram, breakdowns and organogram. The second chapter updates the already-discussed risk assessment, now expanded to the subsystem level. The third chapter contains the definition of all subsystems of the wind turbine, supported by an N2 chart showing how everything is interconnected. In the same chapter, a description of the initial models used to design the different turbine elements is also present. Chapter 4 presents all the needed trade-offs to define the final concept to be analysed. The next chapter presents the operation and logistics strategy that will be further explored once more information about the actual design of the turbine is defined. Next, a verification and validation plan is shown. In this chapter, V&V is also discussed and performed for the already used models. The following chapter summarises all the outcomes obtained so far, showing the overall conceptual design of the wind turbine together with a performance analysis. Finally, the last chapter consists of the sustainability strategy undertaken for the design process.

1.2. Work Breakdown Structure and Work Flow Diagram

Work breakdown structure was made in order to help determine the team organization and the division of responsibilities. The design work was split first into the high-level tasks: designing the subsystems, updating the system description, detailing operation and risks, making economic analysis, and creating the necessary models.

From there, each of these tasks was split into smaller tasks, majority of which were in turn again split into smaller tasks. Not all were broken down to same degree and not all were broken down to same size.

Following the work breakdown structure, the tasks were organized based on interdependence, within the same block. First the five high-level tasks were ordered. The high-level tasks consisted of tasks which were still substantial in size, but could be better parallelized, so the function flow diagram was produced for the middle level again. The numbering in the work flow diagram remains unchanged from the work breakdown structure.

1.3. Team organisation

The current section presents the team organisation based on technical and non-technical roles, the work flow diagram and work breakdown structure.

Within the organogram, the non-technical ones are displayed in yellow, while the technical ones are outlined in blue. A few more colors can be observed as they suggest different sectors that will be investigated during the engineering analysis. The organogram is presented in the following figure:

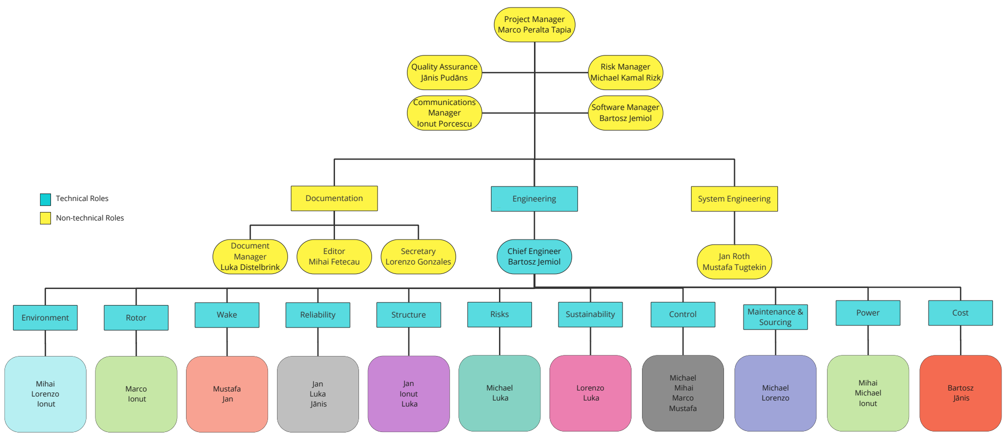
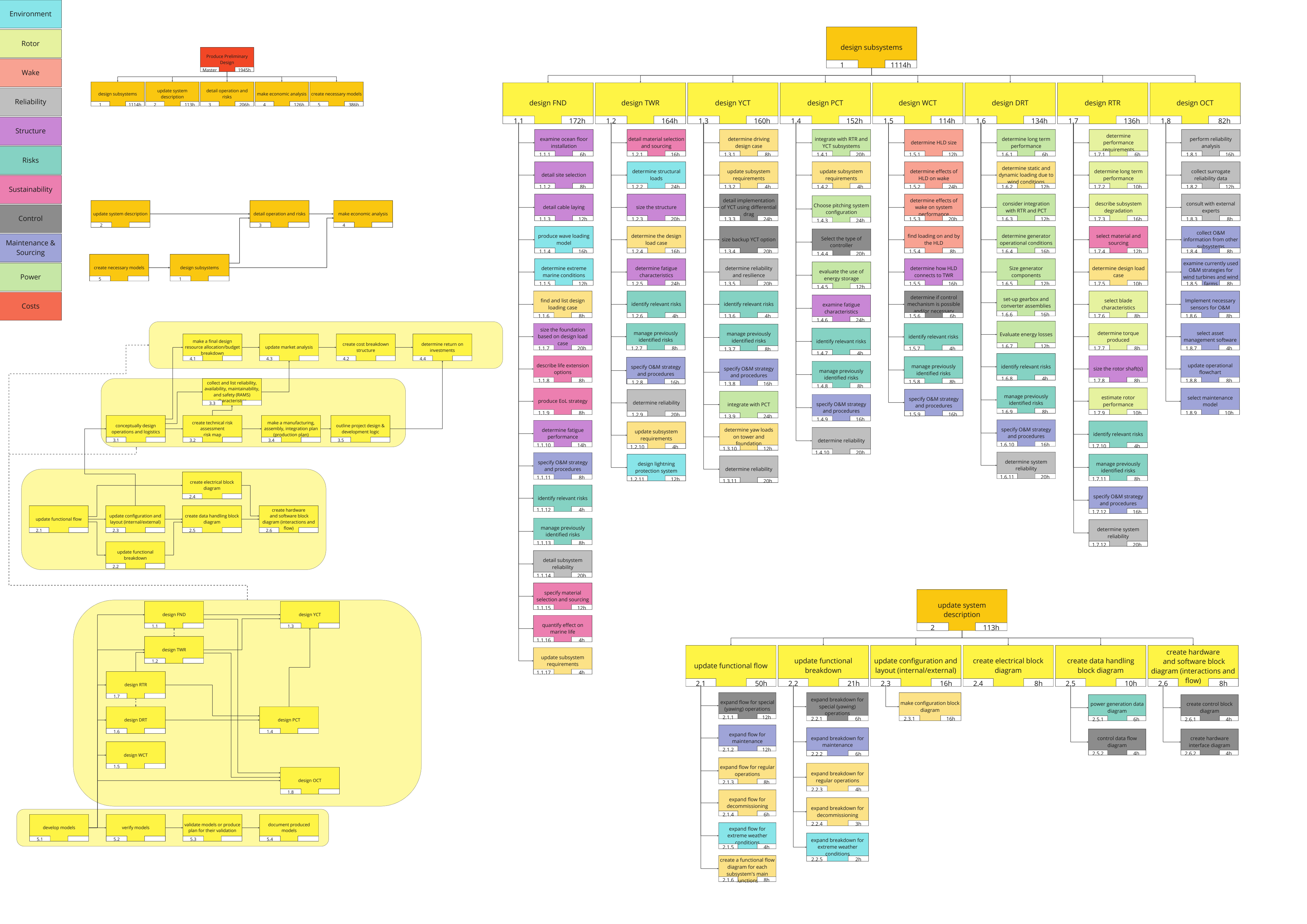


Figure 1.1: *Organogram showing the organization of the group*

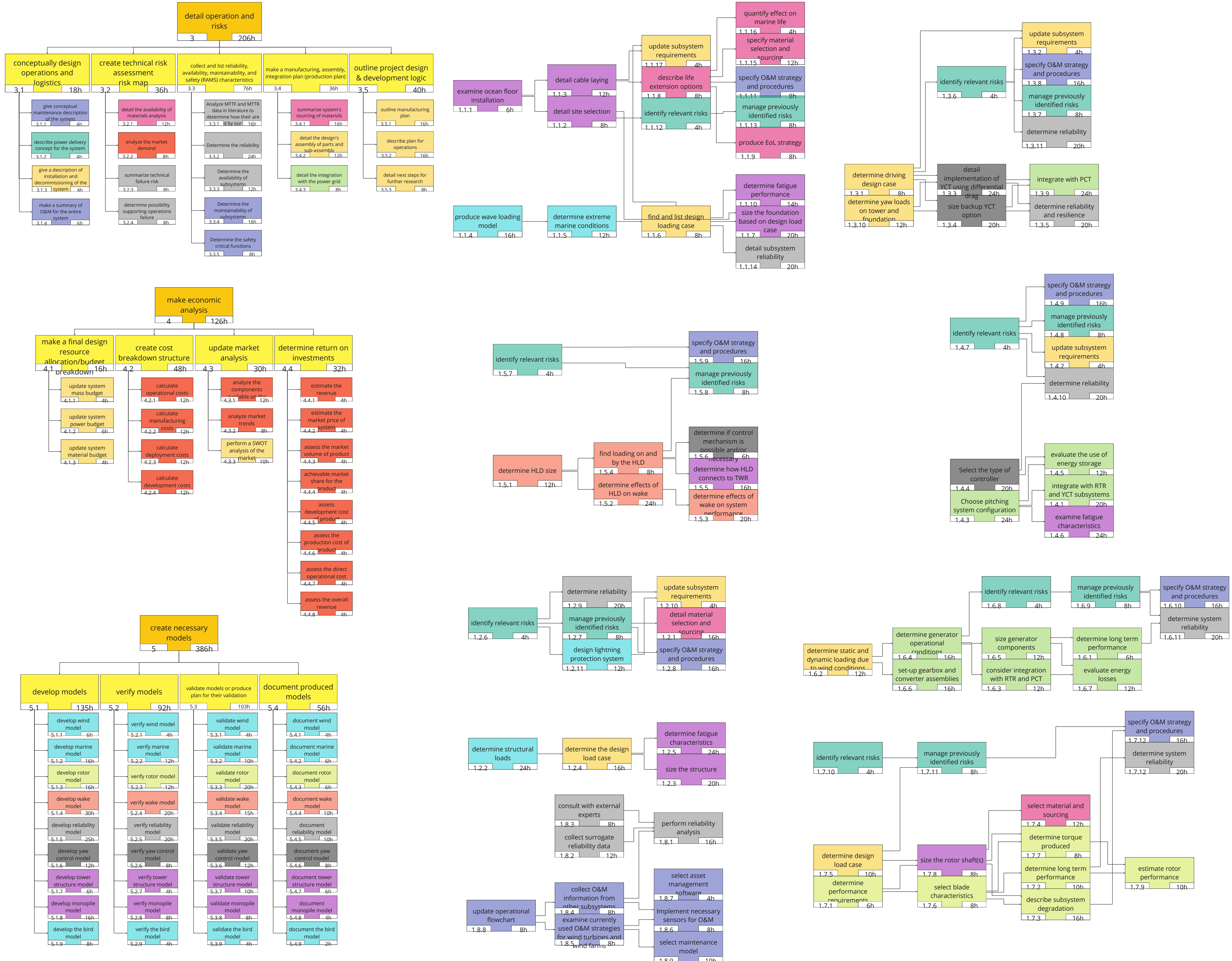
The non-technical roles from fig. 1.1 did not change from the project plan of the design synthesis exercise. Several technical sections have been added since the design analysis will proceed with the detailed design study, which will be presented in the final report. A brief description of each engineering segment is presented below:

1. Environment: concerns the study of external impact on the structure due to the environment, such as the impact of wildlife, tidal and aerodynamic loads for various weather conditions. For instance, this will involve working on the wind model.
2. Rotor: concerns the rotor design analysis based on performance, blade characteristics, torque, etc.
3. Wake: concerns the design of the high lift device based on wake management and its size.
4. Reliability: concerns the probability of failure of the system based on the failure rates of the components and will involve making reliability diagrams.
5. Structure: concerns the analysis of the entire support structure based on its size, ocean floor installation, fatigue study, etc.
6. Risks: concerns the analysis of the potential encountered risks along with their consequences and mitigation measures for all wind turbine components.
7. Sustainability: concerns the material selection, space efficiency analysis and the environmental impact
8. Control: concerns the yawing system design and its operation strategy.
9. Maintenance: concerns the maintenance strategy adopted for various elements of the wind turbine
10. Power: concerns the energy balance evaluation and designing several components for the drive train and power control subsystem.
11. Costs: concerns the market analysis along with the cost estimations for different life phases of the wind turbine.

To manage the time, a Gantt chart is used.Tasks from the breakdown were assigned to individuals or groups, with the completion times adjusted accordingly. The Gantt chart can be seen below.

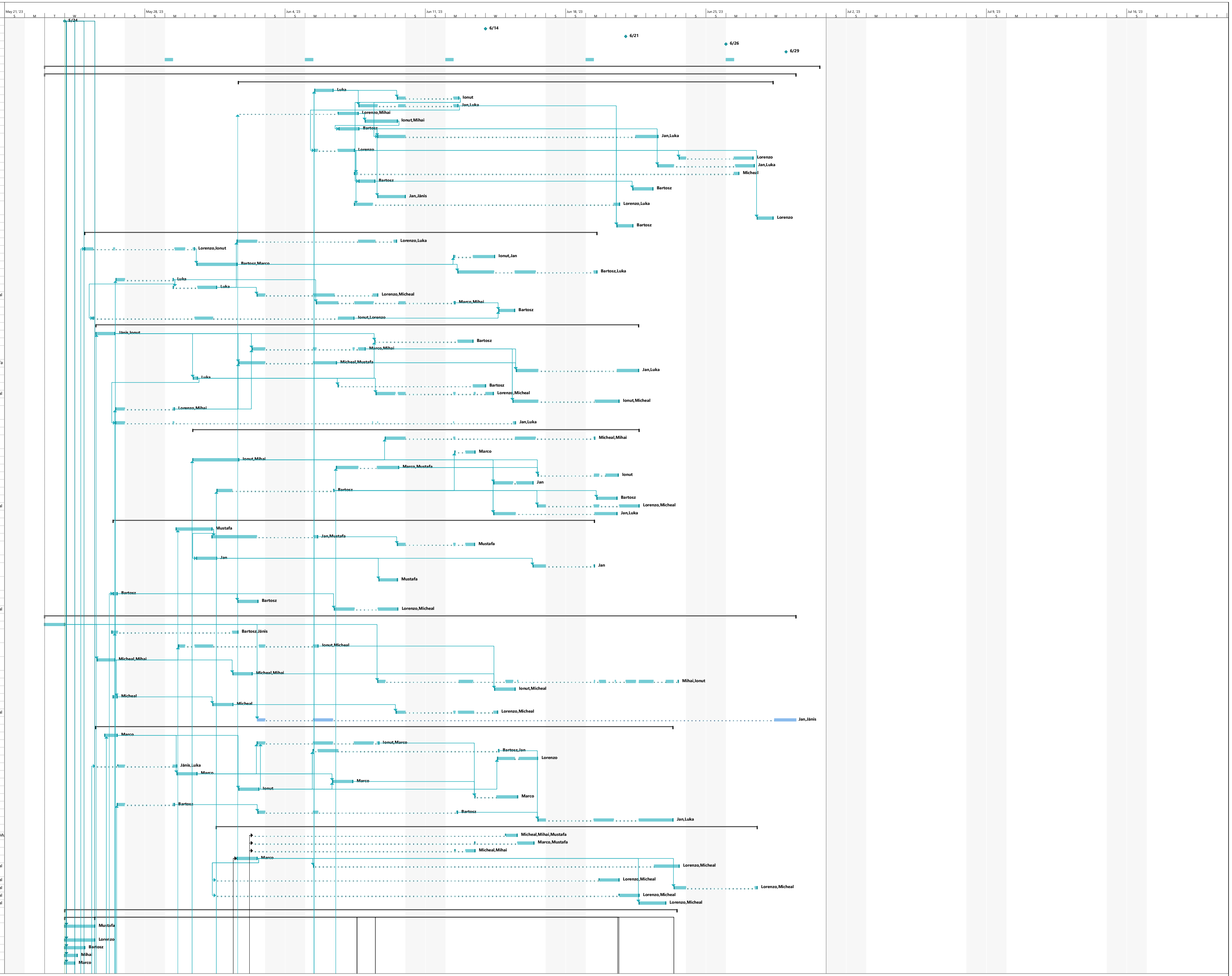


Environment
Rotor
Wake
Reliability
Structure
Risks
Sustainability
Control
Maintenance & Sourcing
Power
Costs
Produce Preliminary Design
Master
1945h
design subsystems
1
1114h
update system description
2
113h
detail operation and risks
3
206h
make economic analysis
4
126h
create necessary models
5
386h
update system description
2
detail operation and risks
3
make economic analysis
4
create necessary models
5
design subsystems
1
make a final design resource allocation/budget breakdown
4.1
update market analysis
4.3
create cost breakdown structure
4.2
determine return on investments
4.4
collect and list reliability, availability, maintainability, and safety (RAMS) characteristics
3.3
conceptually design operations and logistics
3.1
create technical risk assessment risk map
3.2
make a manufacturing, assembly, integration plan (production plan)
3.4
outline project design & development logic
3.5
create electrical block diagram
2.4
update functional flow
2.1
update configuration and layout (internal/external)
2.3
create data handling block diagram
2.5
create hardware and software block diagram (interactions and flow)
2.6
update functional breakdown
2.2
design FND
1.1
design YCT
1.3
design TWR
1.2
design RTR
1.7
design DRT
1.6
design PCT
1.4
design WCT
1.5
design OCT
1.8
develop models
5.1
verify models
5.2
validate models or produce plan for their validation
5.3
document produced models
5.4
design subsystems
1
1114h
design FND
1.1
172h
design TWR
1.2
164h
design YCT
1.3
160h
design PCT
1.4
152h
design WCT
1.5
114h
design DRT
1.6
134h
design RTR
1.7
136h
design OCT
1.8
82h
examine ocean floor installation
1.1.1
6h
detail site selection
1.1.2
8h
detail cable laying
1.1.3
12h
produce wave loading model
1.1.4
16h
determine extreme marine conditions
1.1.5
12h
find and list design loading case
1.1.6
8h
size the foundation based on design load case
1.1.7
20h
describe life extension options
1.1.8
8h
produce EoL strategy
1.1.9
8h
determine fatigue performance
1.1.10
14h
specify O&M strategy and procedures
1.1.11
8h
identify relevant risks
1.1.12
4h
manage previously identified risks
1.1.13
8h
detail subsystem reliability
1.1.14
20h
specify material selection and sourcing
1.1.15
12h
quantify effect on marine life
1.1.16
4h
update subsystem requirements
1.1.17
4h
detail material selection and sourcing
1.2.1
16h
determine structural loads
1.2.2
24h
size the structure
1.2.3
20h
determine the design load case
1.2.4
16h
determine fatigue characteristics
1.2.5
24h
identify relevant risks
1.2.6
4h
manage previously identified risks
1.2.7
8h
specify O&M strategy and procedures
1.2.8
16h
determine reliability
1.2.9
20h
update subsystem requirements
1.2.10
4h
design lightning protection system
1.2.11
12h
determine driving design case
1.3.1
8h
update subsystem requirements
1.3.2
4h
detail implementation of YCT using differential drag
1.3.3
24h
size backup YCT option
1.3.4
20h
determine reliability and resilience
1.3.5
20h
identify relevant risks
1.3.6
4h
manage previously identified risks
1.3.7
8h
specify O&M strategy and procedures
1.3.8
16h
integrate with PCT
1.3.9
24h
determine yaw loads on tower and foundation
1.3.10
12h
determine reliability
1.3.11
20h
integrate with RTR and YCT subsystems
1.4.1
20h
update subsystem requirements
1.4.2
4h
Choose pitching system configuration
1.4.3
24h
Select the type of controller
1.4.4
20h
evaluate the use of energy storage
1.4.5
12h
examine fatigue characteristics
1.4.6
24h
identify relevant risks
1.4.7
4h
manage previously identified risks
1.4.8
8h
specify O&M strategy and procedures
1.4.9
16h
determine reliability
1.4.10
20h
determine HLD size
1.5.1
12h
determine effects of HLD on wake
1.5.2
24h
determine effects of wake on system performance
1.5.3
20h
find loading on and by the HLD
1.5.4
8h
determine how HLD connects to TWR
1.5.5
16h
determine if control mechanism is possible and/or necessary
1.5.6
6h
identify relevant risks
1.5.7
4h
manage previously identified risks
1.5.8
8h
specify O&M strategy and procedures
1.5.9
16h
determine long term performance
1.6.1
6h
determine static and dynamic loading due to wind conditions
1.6.2
12h
consider integration with RTR and PCT
1.6.3
12h
determine generator operational conditions
1.6.4
16h
Size generator components
1.6.5
12h
set-up gearbox and converter assemblies
1.6.6
16h
Evaluate energy losses
1.6.7
12h
identify relevant risks
1.6.8
4h
manage previously identified risks
1.6.9
8h
specify O&M strategy and procedures
1.6.10
16h
determine system reliability
1.6.11
20h
determine performance requirements
1.7.1
6h
determine long term performance
1.7.2
10h
describe subsystem degradation
1.7.3
16h
select material and sourcing
1.7.4
12h
determine design load case
1.7.5
10h
select blade characteristics
1.7.6
8h
determine torque produced
1.7.7
8h
size the rotor shaft(s)
1.7.8
8h
estimate rotor performance
1.7.9
10h
identify relevant risks
1.7.10
4h
manage previously identified risks
1.7.11
8h
specify O&M strategy and procedures
1.7.12
16h
determine system reliability
1.7.12
20h
perform reliability analysis
1.8.1
16h
collect surrogate reliability data
1.8.2
12h
consult with external experts
1.8.3
8h
collect O&M information from other subsystems
1.8.4
8h
examine currently used O&M strategies for wind turbines and wind farms
1.8.5
8h
Implement necessary sensors for O&M
1.8.6
8h
select asset management software
1.8.7
4h
update operational flowchart
1.8.8
8h
select maintenance model
1.8.9
10h
update system description
2
113h
update functional flow
2.1
50h
update functional breakdown
2.2
21h
update configuration and layout (internal/external)
2.3
16h
create electrical block diagram
2.4
8h
create data handling block diagram
2.5
10h
create hardware and software block diagram (interactions and flow)
2.6
8h
expand flow for special (yawing) operations
2.1.1
12h
expand flow for maintenance
2.1.2
12h
expand flow for regular operations
2.1.3
8h
expand flow for decommissioning
2.1.4
6h
expand flow for extreme weather conditions
2.1.5
4h
create a functional flow diagram for each subsystem's main functions
2.1.6
8h
expand breakdown for special (yawing) operations
2.2.1
6h
expand breakdown for maintenance
2.2.2
6h
expand breakdown for regular operations
2.2.3
4h
expand breakdown for decommissioning
2.2.4
3h
expand breakdown for extreme weather conditions
2.2.5
2h
make configuration block diagram
2.3.1
16h
power generation data diagram
2.5.1
6h
control data flow diagram
2.5.2
4h
create control block diagram
2.6.1
4h
create hardware interface diagram
2.6.2
4h



detail operation and risks
3 206h
conceptually design operations and logistics
3.1 18h
give conceptual maintenance description of the system
3.1.1 4h
describe power delivery concept for the system
3.1.2 4h
give a description of installation and decommissioning of the system
3.1.3 4h
make a summary of O&M for the entire system
3.1.4 6h
create technical risk assessment risk map
3.2 36h
detail the availability of materials analysis
3.2.1 12h
analyze the market demand
3.2.2 8h
summarize technical failure risk
3.2.3 8h
determine possibility supporting operations failure
3.2.4 8h
collect and list reliability, availability, maintainability, and safety (RAMS) characteristics
3.3 76h
Analyze MTTF and MTTR data in literature to determine how their are
3.3.1 16h
Determine the reliability
3.3.2 24h
Determine the availability of subsystems
3.3.3 12h
Determine the maintainability of subsystems
3.3.4 16h
Determine the safety critical functions
3.3.5 8h
make a manufacturing, assembly, integration plan (production plan)
3.4 36h
summarize system's sourcing of materials
3.4.1 16h
detail the design's assembly of parts and sub-assembly
3.4.2 12h
detail the integration with the power grid
3.4.3 8h
outline project design & development logic
3.5 40h
outline manufacturing plan
3.5.1 16h
describe plan for operations
3.5.2 16h
detail next steps for further research
3.5.3 8h
examine ocean floor installation
1.1.1 6h
detail cable laying
1.1.3 12h
detail site selection
1.1.2 8h
update subsystem requirements
1.1.17 4h
describe life extension options
1.1.8 8h
identify relevant risks
1.1.12 4h
quantify effect on marine life
1.1.16 4h
specify material selection and sourcing
1.1.15 12h
specify O&M strategy and procedures
1.1.11 8h
manage previously identified risks
1.1.13 8h
produce EoL strategy
1.1.9 8h
produce wave loading model
1.1.4 16h
determine extreme marine conditions
1.1.5 12h
find and list design loading case
1.1.6 8h
determine fatigue performance
1.1.10 14h
size the foundation based on design load case
1.1.7 20h
detail subsystem reliability
1.1.14 20h
identify relevant risks
1.3.6 4h
update subsystem requirements
1.3.2 4h
specify O&M strategy and procedures
1.3.8 16h
manage previously identified risks
1.3.7 8h
determine reliability
1.3.11 20h
determine driving design case
1.3.1 8h
determine yaw loads on tower and foundation
1.3.10 12h
detail implementation of YCT using differential drag
1.3.3 24h
size backup YCT option
1.3.4 20h
integrate with PCT
1.3.9 24h
determine reliability and resilience
1.3.5 20h
make economic analysis
4 126h
make a final design resource allocation/budget breakdown
4.1 16h
update system mass budget
4.1.1 4h
update system power budget
4.1.2 6h
update system material budget
4.1.3 4h
create cost breakdown structure
4.2 48h
calculate operational costs
4.2.1 12h
calculate manufacturing costs
4.2.2 12h
calculate deployment costs
4.2.3 12h
calculate development costs
4.2.4 12h
update market analysis
4.3 30h
analyze the components available on the
4.3.1 12h
analyze market trends
4.3.2 8h
perform a SWOT analysis of the market
4.3.3 10h
determine return on investments
4.4 32h
estimate the revenue
4.4.1 4h
estimate the market price of system
4.4.2 4h
assess the market volume of product
4.4.3 4h
achievable market share for the product
4.4.4 4h
assess development cost of product
4.4.5 4h
assess the production cost of product
4.4.6 4h
assess the direct operational cost
4.4.7 4h
assess the overall revenue
4.4.8 4h
identify relevant risks
1.5.7 4h
specify O&M strategy and procedures
1.5.9 16h
manage previously identified risks
1.5.8 8h
determine HLD size
1.5.1 12h
find loading on and by the HLD
1.5.4 8h
determine effects of HLD on wake
1.5.2 24h
determine if control mechanism is possible and/or necessary
1.5.6 6h
determine how HLD connects to TWR
1.5.5 16h
determine effects of wake on system performance
1.5.3 20h
identify relevant risks
1.4.7 4h
specify O&M strategy and procedures
1.4.9 16h
manage previously identified risks
1.4.8 8h
update subsystem requirements
1.4.2 4h
determine reliability
1.4.10 20h
Select the type of controller
1.4.4 20h
Choose pitching system configuration
1.4.3 24h
evaluate the use of energy storage
1.4.5 12h
integrate with RTR and YCT subsystems
1.4.1 20h
examine fatigue characteristics
1.4.6 24h
create necessary models
5 386h
develop models
5.1 135h
develop wind model
5.1.1 6h
develop marine model
5.1.2 16h
develop rotor model
5.1.3 16h
develop wake model
5.1.4 30h
develop reliability model
5.1.5 25h
develop yaw control model
5.1.6 12h
develop tower structure model
5.1.7 6h
develop monopile model
5.1.8 16h
develop the bird model
5.1.9 8h
verify models
5.2 92h
verify wind model
5.2.1 4h
verify marine model
5.2.2 12h
verify rotor model
5.2.3 12h
verify wake model
5.2.4 20h
verify reliability model
5.2.5 20h
verify yaw control model
5.2.6 8h
verify tower structure model
5.2.7 4h
verify monopile model
5.2.8 8h
verify the bird model
5.2.9 4h
validate models or produce plan for their validation
5.3 103h
validate wind model
5.3.1 4h
validate marine model
5.3.2 10h
validate rotor model
5.3.3 20h
validate wake model
5.3.4 15h
validate reliability model
5.3.5 20h
validate yaw control model
5.3.6 12h
validate tower structure model
5.3.7 10h
validate monopile model
5.3.8 8h
validate the bird model
5.3.9 4h
document produced models
5.4 56h
document wind model
5.4.1 4h
document marine model
5.4.2 6h
document rotor model
5.4.3 6h
document wake model
5.4.4 10h
document reliability model
5.4.5 10h
document yaw control model
5.4.6 8h
document tower structure model
5.4.7 6h
document monopile model
5.4.8 4h
document the bird model
5.4.9 2h
identify relevant risks
1.2.6 4h
determine reliability
1.2.9 20h
manage previously identified risks
1.2.7 8h
design lightning protection system
1.2.11 12h
update subsystem requirements
1.2.10 4h
detail material selection and sourcing
1.2.1 16h
specify O&M strategy and procedures
1.2.8 16h
determine structural loads
1.2.2 24h
determine the design load case
1.2.4 16h
determine fatigue characteristics
1.2.5 24h
size the structure
1.2.3 20h
consult with external experts
1.8.3 8h
collect surrogate reliability data
1.8.2 12h
perform reliability analysis
1.8.1 16h
update operational flowchart
1.8.8 8h
collect O&M information from other subsystems
1.8.4 8h
examine currently used O&M strategies for wind turbines and wind farms
1.8.5 8h
select asset management software
1.8.7 4h
Implement necessary sensors for O&M
1.8.6 8h
select maintenance model
1.8.9 10h
identify relevant risks
1.6.8 4h
manage previously identified risks
1.6.9 8h
specify O&M strategy and procedures
1.6.10 16h
determine system reliability
1.6.11 20h
determine static and dynamic loading due to wind conditions
1.6.2 12h
determine generator operational conditions
1.6.4 16h
set-up gearbox and converter assemblies
1.6.6 16h
size generator components
1.6.5 12h
consider integration with RTR and PCT
1.6.3 12h
determine long term performance
1.6.1 6h
evaluate energy losses
1.6.7 12h
identify relevant risks
1.7.10 4h
manage previously identified risks
1.7.11 8h
specify O&M strategy and procedures
1.7.12 16h
determine system reliability
1.7.12 20h
determine design load case
1.7.5 10h
determine performance requirements
1.7.1 6h
size the rotor shaft(s)
1.7.8 8h
select blade characteristics
1.7.6 8h
select material and sourcing
1.7.4 12h
determine torque produced
1.7.7 8h
determine long term performance
1.7.2 10h
describe subsystem degradation
1.7.3 16h
estimate rotor performance
1.7.9 10h

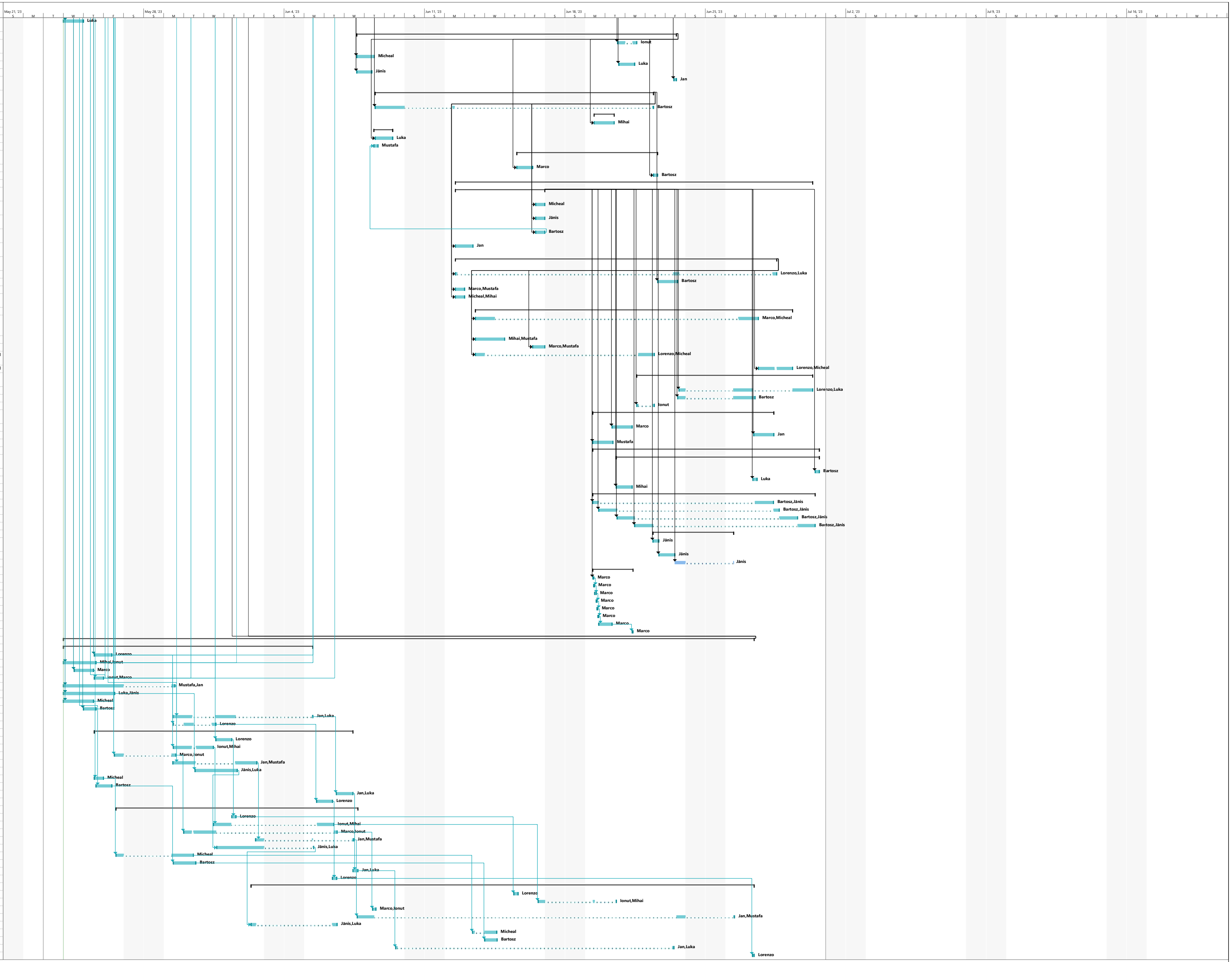
ID	% Compl	Task Name	Duration	Start	Finish	Prede	Resource Names
1	0%	Detailed design begins	0 days	Wed 5/24/23	Wed 5/24/23		
2	0%	Jury summary	0 days	Wed 6/14/23	Wed 6/14/23		
3	0%	Draft of final report & poster	0 days	Wed 6/21/23	Wed 6/21/23		
4	0%	Final review	0 days	Mon 6/26/23	Mon 6/26/23		
5	0%	Symposium	0 days	Thu 6/29/23	Thu 6/29/23		
6	**0%**	**Weekly mentour meeting**	**20.19 days**	**Mon 5/29/23**	**Mon 6/26/23**		
12	**0%**	**Detailed Design**	**28.94 days**	**Tue 5/23/23**	**Fri 6/30/23**		
13	**0%**	**1. Design subsystems**	**27.5 days**	**Tue 5/23/23**	**Thu 6/29/23**		
14	**0%**	**1.1 Design foundation**	**18.19 days**	**Thu 6/1/23**	**Wed 6/28/23**		
15	0%	1.1.1 Examine ocean floor installation	6 hrs	Mon 6/5/23	Tue 6/6/23	186,1	Luka
16	0%	1.1.2 Detail site selection	8 hrs	Fri 6/9/23	Mon 6/12/23	15	Ionut
17	0%	1.1.3 Detail cable laying	12 hrs	Wed 6/7/23	Mon 6/12/23	15	Jan,Luka
18	0%	1.1.4 Produce wave loading model	8 hrs	Thu 6/1/23	Wed 6/7/23	187	Lorenzo,Mihai
19	0%	1.1.5 Determine extreme marine conc	12 hrs	Thu 6/8/23	Fri 6/9/23	18	Ionut,Mihai
20	0%	1.1.6 Find and list design loading case	8 hrs	Tue 6/6/23	Wed 6/7/23	19	Bartosz
21	0%	1.1.7 Size the foundation based on design load case	20 hrs	Thu 6/8/23	Thu 6/22/23	20,16	Jan,Luka
22	0%	1.1.8 Describe lift extension options	8 hrs	Mon 6/5/23	Wed 6/7/23	17	Lorenzo
23	0%	1.1.9 Produce EoL strategy	8 hrs	Fri 6/23/23	Tue 6/27/23	22	Lorenzo
24	0%	1.1.10 Determine fatigue performance	11 hrs	Thu 6/22/23	Tue 6/27/23	20	Jan,Luka
25	0%	1.1.11 Specify O&M strategy and proc	8 hrs	Wed 6/7/23	Mon 6/26/23	22	Micheal
26	0%	1.1.12 Identify relevant risks	4 hrs	Wed 6/7/23	Thu 6/8/23	16	Bartosz
27	0%	1.1.13 Manage previously identified ri	8 hrs	Wed 6/21/23	Thu 6/22/23	26	Bartosz
28	0%	1.1.14 Detail subsystem reliability	10 hrs	Thu 6/8/23	Fri 6/9/23	20	Jan,Jānis
29	0%	1.1.15 Specify material selection and sourcing	12 hrs	Wed 6/7/23	Tue 6/20/23	22	Lorenzo,Luka
30	0%	1.1.16 Quantify effect on marine life	4 hrs	Tue 6/27/23	Wed 6/28/23	22	Lorenzo
31	0%	1.1.17 Update subsystem requiremen	4 hrs	Tue 6/20/23	Wed 6/21/23	17,20	Bartosz
32	**0%**	**1.2 Design the tower**	**17.56 days**	**Thu 5/25/23**	**Mon 6/19/23**		
33	0%	1.2.1 Detail material selection and sou	16 hrs	Thu 6/1/23	Fri 6/9/23	39	Lorenzo,Luka
34	0%	1.2.2 Determine structural loads	10.5 hrs	Thu 5/25/23	Tue 5/30/23	193	Lorenzo,Ionut
35	0%	1.2.3 Size the structure	12 hrs	Mon 6/12/23	Wed 6/14/23	36	Ionut,Jan
36	0%	1.2.4 Determine the design load case	16 hrs	Tue 5/30/23	Thu 6/1/23	34	Bartosz,Marco
37	0%	1.2.5 Determine fatigue characterisitic	24 hrs	Mon 6/12/23	Mon 6/19/23	36	Bartosz,Luka
38	0%	1.2.6 Identify relevant risks	4 hrs	Fri 5/26/23	Mon 5/29/23	193	Luka
39	0%	1.2.7 Manage previously identified risl	8 hrs	Mon 5/29/23	Wed 5/31/23	38	Luka
40	0%	1.2.8 Specify O&M strategy and proce	16 hrs	Fri 6/2/23	Thu 6/8/23	39	Lorenzo,Micheal
41	0%	1.2.9 Determine reliabilty	20 hrs	Mon 6/5/23	Mon 6/12/23	38	Marco,Mihai
42	0%	1.2.10 Update subsystem requiremen	4 hrs	Wed 6/14/23	Thu 6/15/23	41,43	Bartosz
43	0%	1.2.11 Design lightning protection syst	12 hrs	Thu 5/25/23	Wed 6/7/23	38	Ionut,Lorenzo
44	**0%**	**1.3 Design yaw system**	**19.25 days**	**Thu 5/25/23**	**Wed 6/21/23**		
45	0%	1.3.1 Determine driving design case	7.5 hrs	Thu 5/25/23	Fri 5/26/23	192	Jānis,Ionut
46	0%	1.3.2 Update subsystem requirements	4 hrs	Thu 6/8/23	Tue 6/13/23	50,45	Bartosz
47	0%	1.3.3 Detail implementation of yaw system using differential drag	14 hrs	Fri 6/2/23	Wed 6/7/23	45,54	Marco,Mihai
48	0%	1.3.4 Size backup yawing option	19.5 hrs	Thu 6/1/23	Tue 6/6/23	45,54	Micheal,Mustafa
49	0%	1.3.5 Determine reliability and resilen	20 hrs	Thu 6/15/23	Wed 6/21/23	47,48	Jan,Luka
50	0%	1.3.6 Identify relevant risks	4 hrs	Tue 5/30/23	Tue 5/30/23	45	Luka
51	0%	1.3.7 Manage previously identified risl	8 hrs	Tue 6/6/23	Tue 6/13/23	50	Bartosz
52	0%	1.3.8 Specify O&M strategy and proce	16 hrs	Thu 6/8/23	Wed 6/14/23	50	Lorenzo,Micheal
53	0%	1.3.9 Integrate with power control	24 hrs	Thu 6/15/23	Tue 6/20/23	47,48	Ionut,Micheal
54	0%	1.3.10 Determine yaw loads on tower and foundation	6 hrs	Fri 5/26/23	Mon 5/29/23	192	Lorenzo,Mihai
55	0%	1.3.11 Determine reliability	10 hrs	Fri 5/26/23	Thu 6/15/23	50	Jan,Luka
56	**0%**	**1.4 Design power control**	**16.69 days**	**Tue 5/30/23**	**Wed 6/21/23**		
57	0%	1.4.1 Integrate with rotor and yawing subsystems	20 hrs	Fri 6/9/23	Mon 6/19/23	59	Micheal,Mihai
58	0%	1.4.2 Update subsystem reuqirements	4 hrs	Mon 6/12/23	Tue 6/13/23	63	Marco
59	0%	1.4.3 Choose pitching system configur	22 hrs	Tue 5/30/23	Thu 6/1/23	189	Ionut,Mihai
60	0%	1.4.4 Select the type of controller	20 hrs	Tue 6/6/23	Fri 6/9/23	189	Marco,Mustafa
61	0%	1.4.5 Evaluate the use of energy stora	12 hrs	Fri 6/16/23	Tue 6/20/23	59,60	Ionut
62	0%	1.4.6 Examine fatigue characteristocs	12 hrs	Wed 6/14/23	Fri 6/16/23	59	Jan
63	0%	1.4.7 Identify relevant risks	4 hrs	Wed 5/31/23	Tue 6/6/23	189	Bartosz
64	0%	1.4.8 Manage previously indentified ri	8 hrs	Mon 6/19/23	Tue 6/20/23	63	Bartosz
65	0%	1.4.9 Specify O&M strategy and proce	16 hrs	Fri 6/16/23	Wed 6/21/23	63	Lorenzo,Micheal
66	0%	1.4.10 Determine reliability	20 hrs	Wed 6/14/23	Tue 6/20/23	63,60	Jan,Luka
67	**0%**	**1.5 Design wake control**	**16.06 days**	**Fri 5/26/23**	**Mon 6/19/23**		
68	0%	1.5.1 Determine HLD size	12 hrs	Mon 5/29/23	Wed 5/31/23	190	Mustafa
69	0%	1.5.2 Determine effects of HLD on wal	24 hrs	Wed 5/31/23	Mon 6/5/23	68	Jan,Mustafa
70	0%	1.5.3 Determine effects of wake on system performance	8 hrs	Fri 6/9/23	Tue 6/13/23	69	Mustafa
71	0%	1.5.4 Find loading on and by the HLD	8 hrs	Tue 5/30/23	Wed 5/31/23	68	Jan
72	0%	1.5.5 Determine how HLD connects to tower subsystem	8 hrs	Fri 6/16/23	Mon 6/19/23	71	Jan
73	0%	1.5.6 Determine if control mechanism is possible and/or	6 hrs	Thu 6/8/23	Fri 6/9/23	71	Mustafa
74	0%	1.5.7 Identify relevant risks	4 hrs	Fri 5/26/23	Fri 5/26/23	190	Bartosz
75	0%	1.5.8 Manage previously identified risl	8 hrs	Thu 6/1/23	Fri 6/2/23	74	Bartosz
76	0%	1.5.9 Specify O&M strategy and proce	16 hrs	Tue 6/6/23	Fri 6/9/23	74	Lorenzo,Micheal
77	**0%**	**1.6 Design drivetrain**	**27.5 days**	**Tue 5/23/23**	**Thu 6/29/23**		
78	0%	1.6.1 Determine long term performan	1 day?	Tue 5/23/23	Tue 5/23/23		
79	0%	1.6.2 Determine static and dynamic loading due to wind conditions	12 hrs	Fri 5/26/23	Thu 6/1/23	186	Bartosz,Jānis
80	0%	1.6.3 Consider integration with rotor and power control	12 hrs	Mon 5/29/23	Mon 6/5/23	81	Ionut,Micheal
81	0%	1.6.4 Determine generator operational conditions	6 hrs	Thu 5/25/23	Fri 5/26/23	78	Micheal,Mihai
82	0%	1.6.5 Size generator components	7 hrs	Thu 6/1/23	Fri 6/2/23	81	Micheal,Mihai
83	0%	1.6.6 Set-up gearbox and converter as	16 hrs	Thu 6/8/23	Fri 6/23/23	78	Mihai,Ionut
84	0%	1.6.7 Evaluate energy losses	8.5 hrs	Wed 6/14/23	Thu 6/15/23	80,82	Ionut,Micheal
85	0%	1.6.8 Identify relevant risks	4 hrs	Fri 5/26/23	Fri 5/26/23	81	Micheal
86	0%	1.6.9 Manage previously identified risl	8 hrs	Wed 5/31/23	Thu 6/1/23	85	Micheal
87	0%	1.6.10 Specify O&M strategy and proc	14.5 hrs	Fri 6/9/23	Wed 6/14/23	86	Lorenzo,Micheal
88	0%	1.6.11 Determine system reliability	20 hrs	Fri 6/2/23	Thu 6/29/23	86,78	Jan,Jānis
89	**0%**	**1.7 Design rotor**	**20.56 days**	**Thu 5/25/23**	**Fri 6/23/23**		
90	0%	1.7.1 Determine performance require	6 hrs	Fri 5/26/23	Fri 5/26/23	189	Marco
91	0%	1.7.2 Determine long term performan	20 hrs	Fri 6/2/23	Thu 6/8/23	97,95	Ionut,Marco
92	0%	1.7.3 Describe subsystem degradation	10 hrs	Mon 6/5/23	Wed 6/14/23	97,95	Bartosz,Jan
93	0%	1.7.4 Select material and sourcing	12 hrs	Wed 6/14/23	Fri 6/16/23	97	Lorenzo
94	0%	1.7.5 Determine design load case	5 hrs	Thu 5/25/23	Mon 5/29/23	189	Jānis,Luka
95	0%	1.7.6 Select blade characteristics	8 hrs	Mon 5/29/23	Tue 5/30/23	90	Marco
96	0%	1.7.7 Determine torque produced	8 hrs	Tue 6/6/23	Wed 6/7/23	95,97	Marco
97	0%	1.7.8 Size the rotor shaft(s)	8 hrs	Thu 6/1/23	Fri 6/2/23	90	Ionut
98	0%	1.7.9 Estimate rotor performance	10 hrs	Tue 6/13/23	Thu 6/15/23	96,91	Marco
99	0%	1.7.10 Identify relevnat risks	4 hrs	Fri 5/26/23	Mon 5/29/23	189	Bartosz
100	0%	1.7.11 Manage previously identified ri	8 hrs	Fri 6/2/23	Mon 6/12/23	99	Bartosz
101	0%	1.7.12 Specify O&M strategy and proc	20 hrs	Fri 6/16/23	Fri 6/23/23	100,9	Jan,Luka
102	**0%**	**1.8 Develop operation and control strat**	**19 days**	**Wed 5/31/23**	**Tue 6/27/23**		
103	0%	1.8.1 Perform reliability analysis	5 hrs	Fri 6/2/23	Thu 6/15/23	184	Micheal,Mihai,Mu
104	0%	1.8.2 Collect surrogate reliability data	6 hrs	Fri 6/2/23	Fri 6/16/23	184	Marco,Mustafa
105	0%	1.8.3 Consult with external experts	4 hrs	Fri 6/2/23	Tue 6/13/23	184	Micheal,Mihai
106	0%	1.8.4 Collect O&M information	8 hrs	Thu 6/1/23	Fri 6/2/23	184	Marco
107	0%	1.8.5 Examine currently used O&M stratergies for wind turbines and	14 hrs	Mon 6/5/23	Fri 6/23/23	106	Lorenzo,Micheal
108	0%	1.8.6 Implement necessary sensors fo	8 hrs	Wed 5/31/23	Tue 6/20/23	106	Lorenzo,Micheal
109	0%	1.8.7 Select asset management softw	8 hrs	Fri 6/23/23	Tue 6/27/23	106	Lorenzo,Micheal
110	0%	1.8.8 Update operational flowchart	8 hrs	Wed 5/31/23	Wed 6/21/23	106	Lorenzo,Micheal
111	0%	1.8.9 Select maintenance model	8 hrs	Wed 6/21/23	Thu 6/22/23	106	Lorenzo,Micheal
112	**0%**	**2. Update system description**	**22.56 days**	**Wed 5/24/23**	**Fri 6/23/23**		
113	**0%**	**2.1 Update functional flow**	**1.5 days**	**Wed 5/24/23**	**Thu 5/25/23**		
114	0%	2.1.1 Expand flow for special (yawing) operations	12 hrs	Wed 5/24/23	Thu 5/25/23	1	Mustafa
115	0%	2.1.2 Expand flow for maintenance	12 hrs	Wed 5/24/23	Thu 5/25/23	1	Lorenzo
116	0%	2.1.3 Expand flow for regular operatio	8 hrs	Wed 5/24/23	Wed 5/24/23	1	Bartosz
117	0%	2.1.4 Expand flow for decommissionin	6 hrs	Wed 5/24/23	Wed 5/24/23	1	Mihai
118	0%	2.1.5 Expand flow for extreme weather condtions	4 hrs	Wed 5/24/23	Wed 5/24/23	1	Marco



Project: new_mid_to_end_gantt
Date: Wed 5/24/23

Task | Split | Milestone | Summary | Project Summary | Inactive Task | Inactive Milestone | Inactive Summary | Manual Task | Duration-only | Manual Summary Rollup | Manual Summary | Start-only | Finish-only | External Tasks | External Milestone | Deadline | Progress | Manual Progress

ID	% Compl	Task Name	Duration	Start	Finish	Prede	Resource Names
119	0%	2.1.6 Create a functional flow diagram for each subsystem's main	8 hrs	Wed 5/24/23	Wed 5/24/23	1	Luka
120	**0%**	**2.2 Update functional breakdown**	**11.81 days**	**Wed 6/7/23**	**Fri 6/23/23**		
121	0%	2.2.1 Expand breakdown for special (yawing) operations	6 hrs	Tue 6/20/23	Wed 6/21/23	113	Ionut
122	0%	2.2.2 Expand breakdown for maintena	6 hrs	Wed 6/7/23	Thu 6/8/23	113	Micheal
123	0%	2.2.3 Expand breakdown for regular o	4 hrs	Tue 6/20/23	Wed 6/21/23	113	Luka
124	0%	2.2.4 Expand breakdown for decommi	3 hrs	Wed 6/7/23	Thu 6/8/23	113	Jānis
125	0%	2.2.5 Expand breakdown for extreme weather conditions	2 hrs	Fri 6/23/23	Fri 6/23/23	113	Jan
126	**0%**	**2.3 Update configuration and layout (internal/external)**	**9.75 days**	**Thu 6/8/23**	**Thu 6/22/23**		
127	0%	2.3.1 Make configuration block diagra	16 hrs	Thu 6/8/23	Thu 6/22/23	113	Bartosz
128	**0%**	**2.4 Create electrical block diagram**	**1 day**	**Mon 6/19/23**	**Tue 6/20/23**		
129	0%	2.4.1 Create electrical block diagram	8 hrs	Mon 6/19/23	Tue 6/20/23	120	Mihai
130	**0%**	**2.5 Create data handling block diagram**	**0.81 days**	**Thu 6/8/23**	**Fri 6/9/23**		
131	0%	2.5.1 Power generation data diagram	6 hrs	Thu 6/8/23	Fri 6/9/23	120	Luka
132	0%	2.5.2 Control data flow diagram	4 hrs	Thu 6/8/23	Thu 6/8/23	140	Mustafa
133	**0%**	**2.6 Create hardware and software block diagrams**	**5.06 days**	**Thu 6/15/23**	**Thu 6/22/23**		
134	0%	2.6.1 Create control block diagram	4 hrs	Thu 6/15/23	Fri 6/16/23	120	Marco
135	0%	2.6.2 Create hardware interface diagr	4 hrs	Thu 6/22/23	Thu 6/22/23	120	Bartosz
136	**0%**	**3. Detial operation and risks**	**13.56 days**	**Mon 6/12/23**	**Fri 6/30/23**		
137	**0%**	**3.1 Conceptually design operations and logistics**	**4.5 days**	**Mon 6/12/23**	**Fri 6/16/23**		
138	0%	3.1.1 Give conceptual maintenance description of the system	4 hrs	Fri 6/16/23	Fri 6/16/23	126	Micheal
139	0%	3.1.2 Describe power delivery concept for the system	4 hrs	Fri 6/16/23	Fri 6/16/23	126	Jānis
140	0%	3.1.3 Give a description of installation and decommissioning of the system	4 hrs	Fri 6/16/23	Fri 6/16/23	126	Bartosz
141	0%	3.1.4 Make a summary of O&M for the entire system	6 hrs	Mon 6/12/23	Tue 6/13/23	126	Jan
142	**0%**	**3.2 Create technical risk assessment risk map**	**12.06 days**	**Mon 6/12/23**	**Wed 6/28/23**		
143	0%	3.2.1 Detial the availability of material	12 hrs	Mon 6/12/23	Wed 6/28/23	126	Lorenzo,Luka
144	0%	3.2.2 Analyze the market demand	8 hrs	Thu 6/22/23	Fri 6/23/23	126	Bartosz
145	0%	3.2.3 Summarize technical failure risk	4 hrs	Mon 6/12/23	Mon 6/12/23	126	Marco,Mustafa
146	0%	3.2.4 Determine possibility supporting operations failure	4 hrs	Mon 6/12/23	Mon 6/12/23	126	Micheal,Mihai
147	**0%**	**3.3 Collect and list RAMS characteristics**	**11.56 days**	**Tue 6/13/23**	**Thu 6/29/23**		
148	0%	3.3.1 Analyse MTTF and MTTR data in literature to determine how there are affected by our deisgn	16 hrs	Tue 6/13/23	Tue 6/27/23	142	Marco,Micheal
149	0%	3.3.2 Determine the reliability	12 hrs	Tue 6/13/23	Wed 6/14/23	142	Mihai,Mustafa
150	0%	3.3.3 Determine the availability of sub	6.5 hrs	Fri 6/16/23	Fri 6/16/23	142	Marco,Mustafa
151	0%	3.3.4 Determine the maintainability of subsystems	8 hrs	Tue 6/13/23	Thu 6/22/23	142	Lorenzo,Micheal
152	0%	3.3.5 Determine the safety critical fun	8 hrs	Tue 6/27/23	Thu 6/29/23	142	Lorenzo,Micheal
153	**0%**	**3.4 Make a manufacturing, assembly, integration plan**	**6.44 days**	**Wed 6/21/23**	**Fri 6/30/23**		
154	0%	3.4.1 Summarize system's sourcing of	16 hrs	Fri 6/23/23	Fri 6/30/23	137	Lorenzo,Luka
155	0%	3.4.2 Detail the design's assembly of t	12 hrs	Fri 6/23/23	Tue 6/27/23	137	Bartosz
156	0%	3.4.3 Detail the integration with the p	4 hrs	Wed 6/21/23	Thu 6/22/23	137	Ionut
157	**0%**	**3.5 Outline project design & development logic**	**7.06 days**	**Mon 6/19/23**	**Wed 6/28/23**		
158	0%	3.5.1 Outline manufacturing plan	8 hrs	Tue 6/20/23	Wed 6/21/23	137	Marco
159	0%	3.5.2 Describe plan for operations	8 hrs	Tue 6/27/23	Wed 6/28/23	137	Jan
160	0%	3.5.3 Detail next steps for further rese	8 hrs	Mon 6/19/23	Tue 6/20/23	137	Mustafa
161	**0%**	**4. Make economic analysis**	**9.75 days**	**Mon 6/19/23**	**Fri 6/30/23**		
162	**0%**	**4.1 Make a final design resource allocation/budget breakdown**	**8.38 days**	**Tue 6/20/23**	**Fri 6/30/23**		
163	0%	4.1.1 Update system mass budget	4 hrs	Fri 6/30/23	Fri 6/30/23	137	Bartosz
164	0%	4.1.2 Update system power budget	4 hrs	Tue 6/27/23	Tue 6/27/23	137	Luka
165	0%	4.1.3 Update system material budget	4 hrs	Tue 6/20/23	Wed 6/21/23	137	Mihai
166	**0%**	**4.2 Create cost breakdown structure**	**9.25 days**	**Mon 6/19/23**	**Fri 6/30/23**		
167	0%	4.2.1 Calculate operational costs	12 hrs	Mon 6/19/23	Wed 6/28/23	137	Bartosz,Jānis
168	0%	4.2.2 Calculate manufacturing costs	12 hrs	Mon 6/19/23	Wed 6/28/23	137	Bartosz,Jānis
169	0%	4.2.3 Calculate deployment costs	12 hrs	Tue 6/20/23	Thu 6/29/23	137	Bartosz,Jānis
170	0%	4.2.4 Calculate development	12 hrs	Wed 6/21/23	Fri 6/30/23	137	Bartosz,Jānis
171	**0%**	**4.3 Update market analysis**	**2.06 days**	**Thu 6/22/23**	**Mon 6/26/23**		
172	0%	4.3.1 Analyze the components available on the market	6 hrs	Thu 6/22/23	Thu 6/22/23	137	Jānis
173	0%	4.3.2 Analyze market trends	4 hrs	Thu 6/22/23	Fri 6/23/23	137	Jānis
174	0%	4.3.3 Perform a SWOT analysis of the	5 hrs	Fri 6/23/23	Mon 6/26/23	137	Jānis
175	**0%**	**4.4 Determine return on investments**	**2 days**	**Mon 6/19/23**	**Wed 6/21/23**		
176	0%	4.4.1 Estimate the revenue	1 hr	Mon 6/19/23	Mon 6/19/23	137	Marco
177	0%	4.4.2 Estimate the market price of the	1 hr	Mon 6/19/23	Mon 6/19/23	176	Marco
178	0%	4.4.3 Assess the market volume of prc	1 hr	Mon 6/19/23	Mon 6/19/23	177	Marco
179	0%	4.4.4 Achievable market share for the	1 hr	Mon 6/19/23	Mon 6/19/23	178	Marco
180	0%	4.4.5 Assess development cost of proc	1 hr	Mon 6/19/23	Mon 6/19/23	179	Marco
181	0%	4.4.6 Assess the production cost of pr	1 hr	Mon 6/19/23	Mon 6/19/23	180	Marco
182	0%	4.4.7 Assess the direct operational cos	1 hr	Mon 6/19/23	Tue 6/20/23	181	Marco
183	0%	4.4.8 Assess the overall revenue	1 hr	Wed 6/21/23	Wed 6/21/23	182	Marco
184	**0%**	**5. Create neceassary models**	**24.31 days**	**Wed 5/24/23**	**Tue 6/27/23**		
185	**0%**	**5.1 Develop models**	**8.31 days**	**Wed 5/24/23**	**Mon 6/5/23**		
186	0%	5.1.1 Develop wind model	6 hrs	Thu 5/25/23	Fri 5/26/23	1	Lorenzo
187	0%	5.1.2 Develop marine model	14 hrs	Wed 5/24/23	Thu 5/25/23	1	Mihai,Ionut
188	0%	5.1.3a Develop rotor model (part 1)	8 hrs	Wed 5/24/23	Thu 5/25/23	1	Marco
189	0%	5.1.3b Develop rotor model (part 2)	4 hrs	Thu 5/25/23	Thu 5/25/23	188	Ionut,Marco
190	0%	5.1.4 Develop wake model	27 hrs	Wed 5/24/23	Mon 5/29/23	1	Mustafa,Jan
191	0%	5.1.5 Develop reliability model	20.5 hrs	Wed 5/24/23	Fri 5/26/23	1	Luka,Jānis
192	0%	5.1.6 Develop yaw control model	12 hrs	Wed 5/24/23	Thu 5/25/23	1	Micheal
193	0%	5.1.7 Develop tower structure model	6 hrs	Thu 5/25/23	Thu 5/25/23	1	Bartosz
194	0%	5.1.8 Develop monopile model	16 hrs	Mon 5/29/23	Mon 6/5/23	190	Jan,Luka
195	0%	5.1.9 Develop the bird model	8 hrs	Mon 5/29/23	Wed 5/31/23	186	Lorenzo
196	**0%**	**5.2 Verify models**	**8.81 days**	**Thu 5/25/23**	**Wed 6/7/23**		
197	0%	5.2.1 Verify wind model	4 hrs	Wed 5/31/23	Thu 6/1/23	186	Lorenzo
198	0%	5.2.2 Verify marine model	12 hrs	Mon 5/29/23	Wed 5/31/23	187	Ionut,Mihai
199	0%	5.2.3 Verify rotor model	8 hrs	Fri 5/26/23	Mon 5/29/23	189	Marco,Ionut
200	0%	5.2.4 Verify wake model	20 hrs	Mon 5/29/23	Fri 6/2/23	190	Jan,Mustafa
201	0%	5.2.5 Verify reliability model	18.5 hrs	Tue 5/30/23	Thu 6/1/23	191	Jānis,Luka
202	0%	5.2.6 Verify yaw control model	4 hrs	Thu 5/25/23	Thu 5/25/23	192	Micheal
203	0%	5.2.7 Verify tower structure mode	4 hrs	Thu 5/25/23	Fri 5/26/23	193	Bartosz
204	0%	5.2.8 Verify monopile model	5 hrs	Tue 6/6/23	Wed 6/7/23	194	Jan,Luka
205	0%	5.2.9 Verify the bird model	4 hrs	Mon 6/5/23	Tue 6/6/23	195	Lorenzo
206	**0%**	**5.3 Validate/make plan for model valida**	**8.19 days**	**Fri 5/26/23**	**Wed 6/7/23**		
207	0%	5.3.1 Validate wind model	4 hrs	Thu 6/1/23	Thu 6/1/23	197	Lorenzo
208	0%	5.3.2 Validate marine model	10 hrs	Wed 5/31/23	Tue 6/6/23	198	Ionut,Mihai
209	0%	5.3.3 Validate rotor model	14.5 hrs	Tue 5/30/23	Tue 6/6/23	199	Marco,Ionut
210	0%	5.3.4 Validate wake model	6 hrs	Fri 6/2/23	Wed 6/7/23	200	Jan,Mustafa
211	0%	5.3.5 Validate reliability model	18.5 hrs	Wed 5/31/23	Mon 6/5/23	201	Jānis,Luka
212	0%	5.3.6 Validate yaw control model	12 hrs	Fri 5/26/23	Tue 5/30/23	202	Micheal
213	0%	5.3.7 Validate tower structure model	10 hrs	Mon 5/29/23	Tue 5/30/23	203	Bartosz
214	0%	5.3.8 Validate monopile model	5 hrs	Wed 6/7/23	Wed 6/7/23	204	Jan,Luka
215	0%	5.3.9 Validate the bird model	4 hrs	Tue 6/6/23	Tue 6/6/23	205	Lorenzo
216	**0%**	**5.4 Document produced models**	**17.25 days**	**Fri 6/2/23**	**Tue 6/27/23**		
217	0%	5.4.1 Document wind model	4 hrs	Thu 6/15/23	Thu 6/15/23	207	Lorenzo
218	0%	5.4.2 Document marine model	3.5 hrs	Fri 6/16/23	Tue 6/20/23	208	Ionut,Mihai
219	0%	5.4.3 Document rotor model	3 hrs	Thu 6/8/23	Thu 6/8/23	209	Marco,Ionut
220	0%	5.4.4 Document wake model	10 hrs	Wed 6/7/23	Mon 6/26/23	210	Jan,Mustafa
221	0%	5.4.5 Document reliability model	10 hrs	Fri 6/2/23	Tue 6/6/23	211	Jānis,Luka
222	0%	5.4.6 Document yaw control model	8 hrs	Tue 6/13/23	Wed 6/14/23	212	Micheal
223	0%	5.4.7 Document tower structure mode	6 hrs	Wed 6/14/23	Wed 6/14/23	213	Bartosz
224	0%	5.4.8 Document monopile model	4 hrs	Fri 6/9/23	Fri 6/23/23	214	Jan,Luka
225	0%	5.4.9 Document the bird model	2 hrs	Tue 6/27/23	Tue 6/27/23	215	Lorenzo



Project: new_mid_to_end_gantt
Date: Wed 5/24/23

Task | Split | Milestone | Summary | Project Summary | Inactive Task | Inactive Milestone | Inactive Summary | Manual Task | Duration-only | Manual Summary Rollup | Manual Summary | Start-only | Finish-only | External Tasks | External Milestone | Deadline | Progress | Manual Progress

2
Subsystem Analysis

The challenge of a complicated project usually arises from the ever-increasing number of elements that comprise the final product and how they are interconnected. Thus, to successfully manage a project's degree of complexity, it is imperative to break the system down into convenient sub-systems. In this chapter, the definitive distinction between subsystems is presented, along with their respective functions and boundaries. The sub-system descriptions are given in Section 2.1. After establishing the sub-systems, the interfaces and interdependencies between sub-systems will be presented, as facilitated by an N2 chart, in Section 2.2. The design options are presented using a design option tree in Section 2.3, while some design background and initial considerations are presented in Section 2.4.

2.1. Subsystem definition

The subsystem division, as performed in the Baseline report [6], has been chosen to be maintained for the conceptual design phase since it enables the concurrent trade-off of the individual subsystems. As the division was primarily performed on the basis of functionality. This facilitates the design process and provides more time for the designers to evaluate the conceptual design as a whole and determine if design changes are necessary to meet the requirements. Thus, the subsystems of this multi-rotor system of wind turbines are:

Foundation (FND): The structural assembly that transfers all the system loads to the sea floor. The foundation is meant to be mostly underwater, with the transition piece element linking it to the tower, also known as the topside of the system. The main loads that need to be carried by the foundation are axial gravitational loads, bending moments created by the topside's drag, and the system's lateral forces. The foundation can be either fixed to the sea floor or floating and moored to the sea bed. Tidal loads directly impact the foundation, which can prove critical for dynamic load cases. The foundation is a critical subsystem whose total failure is considered catastrophic.

Tower (TWR): The structural assembly that hosts all the other topside subsystems. The tower's function is to transfer loads to the foundation, offer support for the other topside subsystems, and offer rigidity to the system. The main loads on the tower are expected to be either aerodynamic loads transferred from the rotor subsystem or gravitational loads. Dynamic loads from the rotor subsystem should be considered to avoid resonance. The tower also needs to accommodate for easy maintainability and accessibility. The tower is a critical system whose total failure is considered catastrophic. The tower is prone to fatigue, overload and corrosion failure.

Yaw control (YCT): The mechanical assembly that facilitates the system's full or partial rotation about the vertical axis. The primary function of the yaw control subsystem is to modify the orientation of the rotor subsystem in order to match a specific desired performance. The yaw control can incorporate an autonomous system that orientates the system perpendicular to the wind direction for the best performance or can be guided through special instructions and positions. The subsystem is directly connected to the operation control subsystem. The yaw control mechanism can be either passive or active.

Power control(PCT): The power control subsystem is the regulatory assembly that limits the speed of the rotor so that the drive train may function in its operational window. This subsystem shall monitor the rotation and torque of the rotor throughout all three phases of the power curve. Within the first region, the wind is monitored closely so that when operating conditions are met, the power control subsystem can begin starting up the system. Within the second phase, the power control regulates the rotation of the rotor so that the generator can work with maximum efficiency. The third phase has limited power production defined by limitations of the electrical system or by limiting loads. Thus, the power control subsystem must adjust the rotor RPM so that the power limit is not exceeded.

Wake control (WCT): the subsystem with the function of replenishing the wake of the rotor with "fresh" air so that the drop in velocity after the system is lower than the one encountered by a conventional wind turbine design. The wake control subsystem's purpose is to increase energy density by putting several systems closer to each other without compromising the power delivered.

Drive Train (DRT): the subsystem that captures the rotational energy from the rotor and transforms it with the help of an electric generator into electric energy. This subsystem is generally comprised of several shafts, depending on the use of a gearbox, an electric generator and a converter. As the drive train is considered the most fault-prone subsystem, it is expected that much detail is given to its operation and management to decrease costs and increase uptime.

Rotor (RTR): this subsystem is responsible for capturing energy from the wind and turning it into mechanical rotational energy. This subsystem comprises multiple blades with airfoils, where each blade moves in the wind to create a moment around the rotational access. This moment does mechanical work on the central shaft, which then does mechanical work on the generator. The number of blades directly influences the rotor performance by changing the solidity of the rectangle as described by the actuator rectangle theory. The main limitations that need to be taken into consideration when designing are maximum static loads due to increased rotor speeds and high cyclic loads that can lead to failure through fatigue. Maintenance attention must be allocated to erosion damage to water droplet impacts.

Operation control (OCT): turbine operations begin with the installation and include maintenance, logistics, routine procedures and decommissioning. The operation control can be divided into two parts, hardware and software. The hardware part can be comprised of various types of sensors for asset health monitoring and performance matching, the electrical components necessary for optimum performance, and the access platforms and catwalks designed for inspection and repairs. The software part amounts to the controllers necessary to operate the other control subsystems and the asset management tools required for obtaining as much value as possible from the system. The main potential sources of failure are linked to either electrical faults or management miscommunication.

2.2. Subsystem interfaces

To keep track of all subsystem interactions, an N2-chart is used. This chart can be seen in Figure 2.1. It has subsystems on the diagonal, with their outputs listed horizontally and their inputs vertically. In addition to the pre-established subsystems, the environment, and the central control station are added to the diagonal. The environment includes wind, seawater, weather, and other environmental effects on the system. The central control station can be an onshore or offshore center where the windfarms are monitored and maintenance actions are coordinated from. This chart also shows that the tower is the most dependent subsystem. Another notable trend is that the environment affects many different subsystems.

Environment	Maritime/tidal loads	Seawater corrosion, aerodynamic loads					Water impacts, errosion, wind speed	Wind speeds, direction	Weather condition
	Foundation								
	Aerodynamic and gravitational loads, vibration	Tower	Mass inertia						
	Torque and vibrations	Torque and vibrations	Yaw control		Change in aerodynamic loads and moments		Control swept area		
				Power control			Control RPM and induce aerodynamic loads		
Updraft and local wind speeds		Downforce and drag			Wake control				
		Induce vibrations				Drive train		Measure power, voltage, maintenance parameters (oil)	
		Aerodynamic (bending) loads			Wake	Torsion loads and RPM	Rotor		
			Yaw error	Expected power		Emergency break or park command		Operations control	Maintenance status
								Park for maintenance	Central control station

Figure 2.1: *N2 diagram of the relevant subsystems, the environment and the central control station*

2.3. Design option trees

The current section presents the design options tree for the designed offshore wind turbine as shown in Figure 2.2. The choices that were still valid after the first design options tree, which was presented in the baseline report, will be traded off in Chapter 3.

As depicted in Figure 2.2, a few options have been eliminated without being traded off. For instance, only the central platform truss grid option was considered for the tower structure based on its versatility and ease of access. Only the monopile and moored floater choices were investigated for the foundation analysis. The underwater hybrid structure we not assessed as a result of not being feasible. As a preliminary estimation, the entire system should be approximated with a simplified structure, which is not the case for a hybrid body.

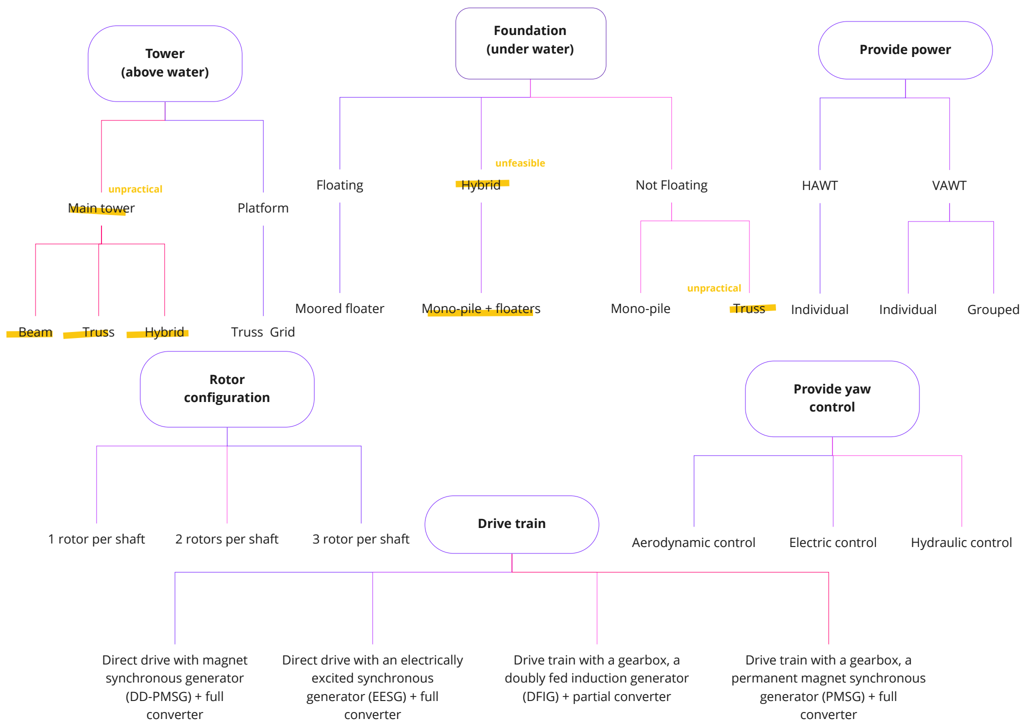


Figure 2.2: *Design Option Tree*

2.4. Design options considerations

In order to familirize with some of the design options previously presented, some design considerations and sizing methods are presented in this section. These consideration cover the estimation of the generator mass, the loads experienced by the foundation, some floater and monopile initial estimations

2.4.1. Generator Mass

Generators account for a significant part of wind turbine mass, therefore, it is important to investigate the impact of rotor design on generator mass. As presented in the design options tree in Figure 2.2, there are three considered designs: HAWT with individual generators, VAWT with individual generators and VAWT with shared shafts and generators. Thus, it is worth determining some basic scaling rules using significant design parameters with the purpose of establishing a basis for comparison for future trade-offs. The analysis will consider individual rotor parameters in relation to the overall dimensions and design parameters of the structure. Then torque of an individual generator will be correlated with rotor parameters. Ultimately total generator mass relation will be obtained. This analysis will be carried out for both grouped rotors and individual rotors.

The relevant parameters for this preliminary sizing are:

- A_{tot} - Total area of the wind turbines,
- H - height of the system,
- W - width of the system,
- A_{ind} - area of a rotor,
- n - number of rotors along a horizontal line,
- d - diameter of a rotor,
- M_g - mass of an individual generator,
- M - total mass of the generators,
- T - individual generator torque,
- P - individual generator power,
- ω - rotor rotational speed,
- v_{inf} - free stream velocity,
- λ - tip speed ratio,
- k_{pac} - packing ratio

In the following calculations, three main assumptions are made. The mass of the generators is proportional to rotor torque [7], the area of a rotor is proportional to the power generated and that the system has a square profile. These assumptions are expressed in eq. (2.1).

$$M_g \propto T \qquad P \propto A_{ind} \qquad W = H \tag{2.1}$$

The rotor diameter is determined by the width of the structure and the number of rotors that need to fit in that width. Angular velocity is the speed of the rotor tip speed divided by the radius of the rotor. Torque is power divided by the rotational speed of the rotor. These definitions are presented in eq. (2.2).

$$d = W/n \qquad \omega = \frac{v_{inf}\lambda}{d/2} \qquad T = P/\omega \propto A_{ind}/\omega \tag{2.2}$$

For grouped VAWT rotors, the total area is divided evenly between the $n \cdot 1$ rotors. The total mass of the generators is thus n times the mass of an individual generator and is proportional to $1/(\lambda n)$, as presented in eq. (2.3) and eq. (2.4).

$$A_{ind} = A/n \rightarrow A_{ind}/\omega = \frac{\frac{A}{n}}{\frac{2v_{inf}\lambda}{d}} = \frac{\frac{A}{n}}{\frac{2v_{inf}\lambda}{W/n}} \tag{2.3}$$

$$M = M_g n \propto Tn \propto A_{ind}/\omega n = \frac{AW}{2v_{inf}\lambda n^2} n \propto \frac{1}{\lambda n} \tag{2.4}$$

For individual rotors (HAWT and VAWT), the total area is divided between n^2 rotors. For HAWT, they do not cover the total area and are not nicely packed, so a correction factor k_{pac} is used. For VAWT, the correction factor k_{pac} is equated to one. Total mass of the generators is then $M = M_g \cdot n^2$ and is proportional to $K_{pac}/(\lambda n)$, as shown in

2.4.2. Foundation loads

This subsection aims to provide loads and moments at the base of the topside structure necessary for sizing the foundation. Since the design is symmetric about the yz-plane, no bending force would roll or push the structure over. Torque effects are negligible since rotor couples are assumed to rotate in opposite directions. The forces that contribute to bending that would pitch the system are the drag of the wake management system, the drag of the structure itself, and the drag of the wind turbines. Yet, the drag of the structure can be assumed to be negligible as the turbine area is much larger.

The structure's first-class weight estimate will be done using extrapolation. Jamieson et al. proposed a design of 48 MW with a mass of 6495 t [8]. Using the square-cube law, the topside mass of a 60MW design can be calculated. This is likely to be a conservative estimate since the mass of the rotors and generators scale linearly with power.

$$\frac{P_1^2}{P_2^2} = \frac{m_1^3}{m_2^3} \rightarrow m_2 = 6495\left(\frac{60}{45}\right)^{\frac{2}{3}} = 7868t \tag{2.5}$$

There are two sources for the estimation of drag loads: the thrust generated by rotors and the drag caused by the wake management subsystem. Given that this is an initial estimation, operational conditions defined by the rated windspeed of the turbine are considered. The following parameters define this load case:

- $C = 30m$ - ground clearance,
- $H = 280m$ - active turbine height
- W - structure width,
- $V_{rat} = 11.2m/s$ - rated wind speed,
- A - active area of the system,
- $\rho = 1.225kg/m^3$ - air density,
- $C_p = 0.47$ - power coefficient,
- $C_t = 0.5$ - trust coefficient,

- $P = 60MW$ - total power of the system,
- D - drag

The active area A can be estimated from the pre-established power requirements using the performance parameters described above, as shown in Equation 2.6.

$$A = (C_p \frac{1}{2} \rho V^3)^{-1} P = \frac{2 \cdot 60 \cdot 10^6}{0.47 \cdot 1.225 \cdot 11.2^3} = 148000 m^2 \tag{2.6}$$

The thrust generated by the rotors, categorised at drag from the point of view of the structure, can then be calculated as shown in Equation 2.7.

$$D_{rated} = C_t \frac{1}{2} \rho V^2 A = 0.5 \cdot \frac{1}{2} \cdot 11.2^2 \cdot 148000 = 5700 kN \tag{2.7}$$

For the drag of the wake management, given that maximum lift is wanted for wake re-energisation, the induced drag will be the main aerodynamic component contributing to the bending moment of the structure. Using some first-class parameters again as presented below, the main loads on the structure are as described in Equation 2.8, Equation 2.9 and in Equation 2.10

- $C_L = 5$ - Lift coefficient
- $e = 0.7$ - Oswald's efficiency factor
- $c = 10m$ - cord
- $C_m = -0.12$ - moment coefficient
- L - lift
- M - moment

$$C_D = \frac{C_L^2}{ARe\pi} = \frac{5^2}{53 \cdot 0.7 \cdot 3.14} = 0.215$$

$$D_{wing} = C_D \frac{1}{2} \rho V^2 W c = 0.215 \cdot \frac{1}{2} \cdot 1.225 \cdot 11.2^2 \cdot 530 \cdot 10 = 87.3 kN \tag{2.8}$$

$$L_{wing} = C_L \frac{1}{2} \rho V^2 W c = 5 \cdot \frac{1}{2} \cdot 1.225 \cdot 11.2^2 \cdot 530 \cdot 10 = 2035 kN \tag{2.9}$$

$$M_{wing} = C_m \frac{1}{2} \rho V^2 W c^2 = -0.12 \cdot \frac{1}{2} \cdot 1.225 \cdot 11.2^2 \cdot 530 \cdot 10^2 = -48.8 kNm \tag{2.10}$$

Additionally, $M_x = 0$ and $F_y = 0$ due to symmetry. Combining all independent loads will yield three principal components: F_x drag force, F_z normal force and M_y a moment, as presented in Equation 2.11, Equation 2.12 and Equation 2.13, respectively. Torque along the vertical axis is assumed to be negligible as rotors can be spun such that the total torque cancels out. Additionally, $M_x = 0$ and $F_y = 0$ due to symmetry.

$$F_x = D_{wing} + D_{rated} = 87.3 kN + 5700 kN = 5787 kN \tag{2.11}$$

$$F_z = mg + L_{wing} = 7868 \cdot 10^3 \cdot 9.81 + 2035 kN = 77389 kN \tag{2.12}$$

$$M_y = D_{wing}(C + H) + D_{rated}(C + H/2) + M_{wing} = 1000 MNm \tag{2.13}$$

2.4.3. Floater design

There are various types of floaters used in offshore wind energy generation. The three most common are the spar floater, the semi-submersible floater, and the tension-leg platform [9]. These designs use different methods of stabilisation. The spar uses a large ballast at the bottom of the floater to get the center of mass below the center of buoyancy (CB). The semi-submersible floater uses pontoons at a distance from the CB to provide reaction moments to tilting. Tension leg platforms are fully submerged pontoons pulled underwater by rods or cables fastened to the ocean floor. The buoyancy of the pontoon keeps the cables in tension, preventing the platform from tilting. As suggested by Jamieson et al., semi-submersible floaters are likely the best suited to designs of the scale considered [8].

To obtain a conceptual design of a floater that can be used in the trade-off in Section 3.5, a scaling method proposed by Wu and Kim is used [1]. This method uses the OC4 DeepCWind Semi-submersible as a basis, together with the NREL 5 MW Wind Turbine, and up-scales them. The configuration of the floater and turbine can be seen below in Table 2.3. Once the turbine is scaled based on the required power output, a scaling factor is chosen for the semi-submersible floater such that the static pitch angle is preserved.

The semi-submersible scaling factor s_s is used to directly scale the outer columns' radius and the side length of the triangle formed by the outer columns, as seen in Equation 2.14 below.

$$r_{column} = r_{column,oc4} s_s \qquad d_{column} = d_{column,oc4} s_s \tag{2.14}$$

The diameter of the central column is scaled to match the diameter of the turbine base. This is done using the turbine scaling parameter s_s, being dependent on the turbine power as seen in Equation 2.15. From this scaling parameter, the central column diameter is found using Equation 2.16

$$s_t = \sqrt{\frac{P}{P_{NREL5}}} \tag{2.15}$$

$$d_{turbine} = d_{central-column} = d_{NREL5}(s_t)^{2.3/3} \tag{2.16}$$

The draft of the floater is kept constant at 20 m, as are all the wall thicknesses. Using the draft, the new outer column radii, the new central column radius, and the new length of the connecting members, the submerged volume can be calculated using Equation 2.17.

$$\nabla = \Sigma(\pi r^2 l_{submerged}) \tag{2.17}$$

The metal mass of the structure can then be calculated with Equation 2.18. The steel density used is 7850 kg/m^3 [10].

$$m_{metal} = \rho_{steel}\Sigma(2\pi r l t) \tag{2.18}$$

For each member, the wall thickness, original length, diameter, and end cap thickness can be found in a report from the National Renewable Energy Laboratory [10].

Once the metal mass of the structure is known, the ballast required to keep the floater at a draft of 20 m can be calculated using Equation 2.19 below. The mass of the mooring is neglected in this estimation, as it is only around 2% of the mass of the original design [1]. A mass equivalent to the F_z calculated in Equation 2.12 is used for the turbine mass.

$$\rho_{water}\nabla = m_{turbine} + m_{metal} + m_{ballast} + m_{mooring} \tag{2.19}$$

To evaluate the stability, the metacenter (BM) is first calculated using the waterplane area of inertia (I_{Aw}) using Equation 2.20.

$$BM = I_{Aw}/\nabla \tag{2.20}$$

With the metacenter, the center of gravity height (z_{CB}), and the center of buoyancy z_{CB}, which stays approximately constant as the draft is kept at a fixed depth, the metacentric height can be calculated, as can be seen in Equation 2.21

$$GM = z_{CB} + BM - z_{CG} \tag{2.21}$$

Once the metacentric height is known, the restoring moment M_{Res} for a certain pitch angle θ_{pitch} can be calculated with Equation 2.22 below. At the static pitch angle, this restoring moment should be as big as the overturning moment M_o. For M_o, M_y as calculated in Equation 2.13 is used.

$$M_{res} = GM \sin(\theta_{pitch}) \cdot m_{total} g_0 \tag{2.22}$$

Table 2.1: *Final 60 MW floater design parameters*

s_s	1.87
Outer column distance [m]	93.5
Outer upper column radius [m]	11.22
Outer lower column radius [m]	22.44
Central column radius [m]	8.42
Metal mass [t]	9742
Ballast mass [t]	37186
Total platform mass [t]	46928
Draft [m]	20
GM [m]	36.4
Static pitch angle [deg]	5

Figure 2.3: *The OC4-DeepCwind semi-submersible platform [12]*

If the obtained static pitch angle is too small or large, the initial scaling factor s_s can be continuously adjusted to get a new design until the right static pitch angle is found. According to Collu and Borg, a reasonable maximum tilt angle is 10°, which is the sum of the static tilt angle and dynamic tilt due to oscillations and waves. Thus, for this design, a static pitch angle of 5° is chosen [11].

The final parameters for the obtained floater design are shown in Table 2.1.

2.4.4. Monopile design

The monopile choice for the foundation is the most conventional option for an offshore wind turbine. The structure should be able to withstand the loads applied and not yield. Three main loading conditions have been identified that could consist of failure modes: bending, torsion and compression. In the conducted analysis, the bending moments, compression and lateral forces are taken as inputs from the study of the structure that will support the wind turbines.

The first step in sizing the monopile is to define the input geometric parameters, which can be varied iteratively in order to optimise the design. The inputs are the length, diameter and thickness of the monopile wall. The optimised output is the total mass of the structure.

Starting the analysis with the bending moment, the flexural formula as described in Equation 2.23 can be used, where M_y is the moments experienced by the monopile, x represents the distance from the neutral axis (N.A) to the point where the stress is evaluated, and I_{yy} is the second moment of inertia.

$$\sigma_{bending} = \frac{M_y \cdot x}{I_{yy}} \tag{2.23}$$

For this stage of the design study, it was assumed that the thickness of the monopile does not vary across its length. The structure of the foundation is a hollow cylinder, having its neutral axis along the central longitudinal axis of the body.It is possible to assume that the cylinder is of the thin-wall type, since the wall thickness is expected to be smaller than the diameter by at least an order of magnitude. Moreover, $I_{xx} = I_{yy}$ as the body is symmetrical with respect to the longitudinal axis. The second moment of area can thus be calculated using Equation 2.24

$$I_{xx} = I_{yy} = \frac{\pi \cdot (D^4 - d^4)}{64} \approx \frac{\pi t D^3}{8} \tag{2.24}$$

The second load considered is the torque experienced by the monopile. The ability of the entire system to yaw towards the wind direction is provided by the yaw control system. However, when this system is blocked due to maintenance reasons or inappropriate weather conditions, the torsional moments generated by the wind will be transferred to the foundation. To evaluate this effect, Equation 2.25 will be used. Following the thin-wall assumption, the approximation within Equation 2.25 can be utilised.

$$\tau_{shear} = \frac{T \cdot r}{J} \approx \frac{T}{2tA_m} \tag{2.25}$$

where T is the torque experienced by the structure, which is the moment around the Z-axis, r is the radius of the shaft, $r = \frac{D}{2}$, and J is the polar moment of inertia. Once more, J is shape geometry-related and it can be computed by using Equation 2.26.

$$J = \frac{\pi \cdot (D^4 - d^4)}{2} \tag{2.26}$$

Lastly, the compression load is considered. The main risk related to this load is Euler buckling, which yields catastrophic failure of the system. The critical buckling force can be calculated as in Equation 2.27:

$$F_{buckling} = \frac{\pi^2 \cdot E \cdot I}{(k \cdot L)^2} [13] \tag{2.27}$$

where E is the Young's Modulus of the material used, L is the length of the monopile, and k is the parameter depending on the boundary conditions chosen. By assuming that the structure is clamped at one end, as it is fixed to the sea bed, k takes the value of two. The buckling stress can be evaluated by dividing the buckling load by the area of the hollow cylinder.

Another crucial load that has a huge influence on the foundation is the wave loading. This is especially important for the fixed base since the body will act as a barrier against the water that is displaced by the wave motion. Typically, the wave loads decrease with water depth. Since the wave height is the highest at the water's surface, this implies that the velocity, moved volume, and thus total energy carried by the wave have their peak values at the surface water level (SWL). This can be observed in Table 2.4.

As depicted in Table 2.4, both the aerodynamic and wave distribution loads vary with the distance from the sea bed and surface level, respectively. As a first estimation of the design, it was assumed that the wave loads are constant along the length of the pile. The second assumption states that the aerodynamic forces on the monopile can be neglected, as the density of air is much lower than the density of water.

The foundation should be designed to withstand the tidal loads in the worst-case scenario. The sea current speed and wave height can be estimated according to historical data. The tidal distributed load can be expressed using the Morisson equation, described as in Equation 2.28:

$$f_{wave} = \rho C_m A\dot{u} + \rho A\dot{u} + 0.5\rho C_D D u|u| [14] \tag{2.28}$$

where $\rho = 1000 kg/m^3$ represents the water density, $C_m = 2$ is the hydrodynamic inertia coefficient of a cylinder. Furthermore, $A = L \cdot D$ is the lateral sectional area of the monopile, D is the diameter of the cylinder, $C_D = 1$ is the drag coefficient and $u = 1.2 m/s$ and $\dot{u} = 0.2 m/s^2$ are the yearly average water velocity and acceleration, respectively [1] [2]. The calculations led to a value of $330480 N/m$, assuming that the diameter of the monopile is 9 m and its length is 60 m. As previously stated, the distribution is assumed to be constant along the length of the foundation, hence yielding an overall force of the 9.91 MN with its assumed application at the half-point of the cylinder. The highest bending moment will be found at the base of the monopile. The final value of the moment generated at sea bed is around 148.716 MNm.

[1] URL: https://ocw.tudelft.nl/wp-content/uploads/Part_4.pdf [cited 17 May 2023]
[2] URL: https://www.offshoreengineering.com/wind-monopile-design [cited 17 May 2023]

Table 2.2: *Final 60 MW monopile design parameters*

F_{wind} [N]	2001560
$F_{airfoil}$ [N]	5699088
$M_{airfoil}$ [Nm]	-13712890
Length without driving [m]	60
Driving length [m]	67
Total length [m]	127
Thickness [m]	0.2
Outer Diameter [m]	9
Mass [t]	5513

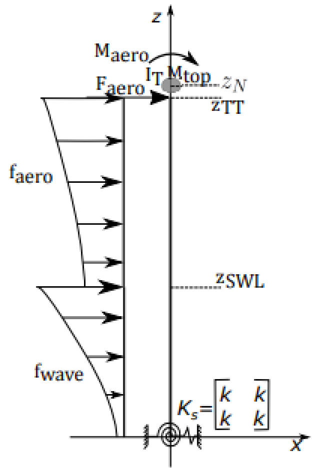


Figure 2.4: *Wave and aerodynamic loads distributions on the foundation structure [14]*

For this preliminary analysis, the torsion experienced by the foundation will not be considered. Despite the fact that torsion could also be a failure mode, it will be assumed that while yawing, the torque is exerted on the bearing, not on the foundation itself. In the most extreme scenario, the yawing system does not operate, leading to the moment to be applied on the cylinder. However, usually, such structures are designed to not fail due to torsion. The critical loads remain bending and column buckling.

The bending moment has its peak value at the bottom of the foundation since the moment arm is maximal there. The loads which haven been used as inputs, were taken from the tower calculation in Subsection 2.4.5, which include the aerodynamic drag of the rotor, the aerodynamic loads generated by the wake control subsystem and the gravitational loads generated by the topside structure. Once more, the peak axial stress value is present at the bottom of the foundation. The combined load method has been used in order to estimate the value of the bending stress and the critical force for Euler buckling. The geometry of the cylinder, namely the total length, outer diameter and thickness, were considered as design inputs since they can be easily iterated. The geometric parameters have been iterated until the desired outcome was achieved, except for the driving length of the monopile, which was computed based on the empirical relation, Equation 2.29 [15], presented in the literature. The output of the design phase was the total mass of the foundation. The results are presented in Table 2.2.

$$L_D = 8D - 5 \tag{2.29}$$

2.4.5. Tower Design

Two possible designs are considered for the tower: a large tower continuing from the foundation supporting platforms and a truss structure carrying loads to a central tower and frame. In Chapter 3, there will not be a trade-off between these two options since the tower's function is to accommodate all other subsystems synergistically. Yet, a basis for comparison can be briefly described here. The final choice will be taken after all other trade-offs have been performed.

The first option is a combination of trusses connected between the wake management subsystem and the baseplate, housing all subsystems. Ancillary struts will carry the bending and compressive loads of the whole system to the central tower and frame. With this option, more surface area can be covered with the same structural mass. The option is also advantageous for mounting the high-lift device on top due to the better distribution of the forces that will be generated.

The second design option consists of a big tower extending from a monopile and platforms placed symmetrically on several levels depending on the design of the turbines. The design can be problematic if the radial length from the central tower is large enough to cause bending, given there is no other support than the platform itself that carries the loads to the main tower. Although it reduces structural complexity by removing the trusses, it introduces complexity due to multi-level yaw and an increased number of yaw systems. The reason why this design is considered an option is that it can provide individual yaw and yaw rate for the levels.

2.5. Rotor number

For the comparison and analysis of the number of rotors, several assumptions are used, and a general power model is explained below. The rotors will be considered with the same airfoil scaled by radius to the different sizes in order to compare the options more accurately. The power equation used as basis for this model is presented in Equation 2.30 [3]

$$P = \frac{1}{2}\eta C_p \rho U^3 A \tag{2.30}$$

with C_p as the rotor power coefficient, ρ as the air density, A as the rotor swept area, η for the generator efficiency and U as the free-stream velocity. The value of C_p depends on various factors. For the purpose of this trade-off, all rotors will be treated as VAWT and thus assumed to have a constant aspect ratio of 5, as it has been shown that changing this value will decrease the C_p [8].

Other major factors that affect the C_p include the Reynolds number, the tip speed ratio, and the rotor solidity, which is equal to the ratio of the rotor area over the rotor's swept area [16]. Both the tip speed ratio and the rotor solidity will be kept constant at optimum values for best performance.

The Reynolds number is written as$Re = VL/\nu$, With V as the upstream air speed, L as the characteristic length of the body, and ν as the kinematic viscosity of the air. The relationship between the Reynolds number and the rotor power is complex to map due to the various flow interactions, with turbulent and laminar flows having different effects on the power[17]. In particular, for the largest rotors, if no empirical data can be found, reports have suggested that during the scaling of such large rotors, Reynolds numbers take a minor role and thus can be ignored [18].

In addition to this, a constant generator efficiency will be used as for this trade-off, all design options will consider similar efficiencies. Also, the effect of wind shear will be ignored, and instead, an average constant wind velocity will be used. This is because the overall area of each of the options will cover the same height distribution, as they will be on the same structure and deployed in the same area. The air density will also be kept constant for the same reason. These assumptions lead to the power equation expressed in Equation 2.31

$$P = 10\eta\rho U^3 R^2 C_p \tag{2.31}$$

The power is a function of various constant parameters, the radius squared and the performance coefficient. This means that for each design option, the total swept area required will be the same for the same total power. However, the minimum area required will vary depending on the power of rotors needed to fit into the power requirements, meaning the possibility of some designs having higher areas is a minor concern.

[3]URL: https://brightspace.tudelft.nl/d2l/le/content/498964/viewContent/3067058/View [cited 15 May 2023]

3

Design Trade-Off

This chapter will cover the trade-offs between the design options identified in Figure 2.2. Section 3.1 presents the way all trade-offs are conducted. Section 3.2 trades-off the rotor orientation. Section 3.5 compares the foundation options. Section 3.6 covers the drive train options. Section 3.3 trades-off the options for the yaw control, while Section 3.4 determines the sizes of rotors and the number of shafts.

3.1. Trade-off organisation

For scoring the different options, a consistent colour-scoring scheme was designed. The scheme has a total of four levels presented in Table 3.1, where a brief description of the meaning of the score is described.

Table 3.1: *The explanation of the scoring used for the trade-off of design options*

Score	Color	Meaning
Unacceptable	Red	The design option has a deficiency which can not be compensated by any other subsystem
Correctable	Orange	The design option has a deficiency which can be corrected by another part of the design
Acceptable	Lime	The design option meets requirement and needs no special considerations
Exceptional	Green	The design option meets requirement and may compensate for another shortcoming

3.2. Rotor orientation trade-off

The goal of this section is to present three design options, HAWT and VAWT laid out in a grid with independent drive trains and VAWT grouped on the same drive train. Mass, operations and maintenance, sustainability and other cost saving options will be evaluated in the section . The sketches of these options are shown in Figure 3.1, Figure 3.2, and Figure 3.3.

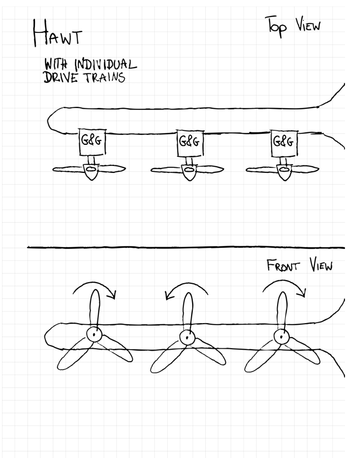


Figure 3.1: *The HAWT-MRS concept*

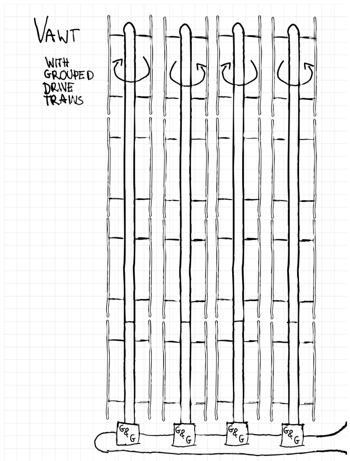


Figure 3.2: *The grouped VAWT rotor concept*

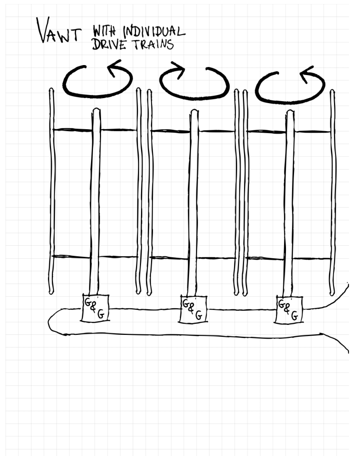


Figure 3.3: *The individual VAWT rotor concept*

HAWT design would resemble a more traditional wind turbine design as horizontal wind turbines are the industry standard. They are typically made out of carbon fibers and have higher wind tip speed ratio of around nine. Manufacturing of HAWT is already well established. VAWTs are less established in the current market. They can be made out of metals more easily and have a tip speed ratio of around 4.5. Manufacturing of VAWT is not as large scale as HAWT but does not include any novel steps or hindrances that would not allow scaling up of manufacturing.

The individual VAWT design is considered to have $n \cdot k$ generators, where $k \approx n$ and $\lambda = 4.5$[8]. The individual HAWT is considered to have $n_2 \cdot k_2$ rotors, where $k_2 \approx n_2$ and $\lambda = 9$[19]. $n_2 = n/2$ and $k_2 = k/2$ (this choice is made to make the designs more comparable). The grouped VAWT design is considered to have $n \cdot 1$ rotors and $\lambda = 4.5$[8]. Grouped rotor or single rotor mainly differs with generator placement. For a grouped rotor design the generators can be located on the lowest level of the tower, making them much more easily accessible, decreasing maintenance costs. For individual rotors the generators are scattered around the wind turbine.

3.2.1. Trade Criteria

The criteria for the trade-off between the three design options are based on the requirements of the system. They aim to make the system as suitable as possible, while staying within the budgets and requirements. The most important criteria were listed below, along with their weights. The short description and justification for each of the criteria are presented below. Along with the description of why these weights were chosen, there is also the justification for the weight awarded to each of the criteria.

CRIT-HvsV-01 (Weight - 20 %): Topside mass (generator, rotors, structure)
CRIT-HvsV-02 (Weight - 20 %): Generator integration
CRIT-HvsV-03 (Weight - 20 %): Generator accessibility
CRIT-HvsV-04 (Weight - 20 %): Number of generators
CRIT-HvsV-05 (Weight - 5 %): Technology readiness level
CRIT-HvsV-06 (Weight - 5 %): Manufacturing readiness level
CRIT-HvsV-07 (Weight - 10 %): Sustainability

CRIT-HvsV-01: Top-side mass is important because it correlates with cost which impacts LCOE. In general larger mass of the structure/generator/rotors is more expensive to source, harder to transport, and more resources are needed to maintain it.

CRIT-HvsV-02: Generator integration relates to space available to select a less space-efficient generator that is more maintainable and cheaper. It is vital to decreasing CAPEX and OPEX and LCOE.

CRIT-HvsV-03: More accessible generators directly lower the generator maintenance and operation costs.

CRIT-HvsV-04: A smaller number of generators decreases system complexity, lowering operation and maintenance costs.

CRIT-HvsV-05: Technology readiness level impacts development costs as well as time to market. As user requirements on this were not given, this trade-off criteria has lower weight.

CRIT-HvsV-06: Manufacturing readiness level impacts time to market and the number of suppliers. As user requirements on this were not given, this trade-off criteria has lower weight.

CRIT-HvsV-07: Sustainability in regards to VAWT vs HAWT concerns the material the rotors and generators are made of. Some materials are easier to recycle than others making the design more sustainable.

3.2.2. Trade-off

This subsection presents the trade-off of the rotor orientation. Firstly some rating considerations are presented for each criterion. Based on the performance of each of the options in this subsection, a score was awarded based on their compliance with the criteria. This is presented in the trade table Table 3.2. The column widths correspond to the weights of the individual criterion. The top side mass of the wind turbine is not included as it was determined that the mass will be approximately the same for all options.

CRIT-HvsV-01: Regarding individual VAWTs, Subsection 2.4.1 shows that the total generator mass is $M \propto \frac{1}{\lambda n} = \frac{1}{4.5n}$. For individual HAWTs, the generator mass is $M \propto \frac{1}{\lambda n_2} = \frac{2}{9n}$. For grouped VAWTS, the generator mass is $M \propto \frac{1}{\lambda n} = \frac{1}{4.5n}$, the same as for individual VAWTs. The rotor mass is considered to be a constant with respect to power so it will be constant and about the same in all cases. The structure mass is a function of the generator mass and the rotor mass.

CRIT-HvsV-02: For individual VAWTs generator size is limited by installation requirements, structure depth, and proximity to rotors. The same can be said for individual HAWTs. For grouped VAWTs generators are further away from the rotors and thus have more space that can be allocated.

CRIT-HvsV-03: For individual VAWTs the generators are scattered around the structure with the possibility to add mezzanines and catwalks to aid in generator accessibility. The same can be said about the HAWT configuration. For grouped VAWTs the generators are grouped at the bottom of the structure with mezzanines and catwalks to aid in accessing generators and getting to them. Having generators closer to water also aids in the assembly of the structure.

CRIT-HvsV-04: For individual VAWTs the number of generators is $n \cdot k$. For individual HAWTs the number of generators is $n \cdot k/4$. For grouped VAWT the number of generators is n.

CRIT-HvsV-05: For individual VAWTs the technology readiness level is 9 which is the highest technology readiness level. The same can be said about the HAWT design. For grouped VAWTs the technology readiness level is 6 which would require prototypes to rise the technology readiness level. Development time and cost were not described as a limiting case by the customer so this is not a problem, however, a plan to raise the technology readiness level should be made.

CRIT-HvsV-06: For individual VAWTs the manufacturing readiness level is 9 which is the highest manufacturing readiness level. The same can be said about the HAWT configuration. For grouped VAWTs the manufacturing readiness level is 1 which is the lowest manufacturing readiness level. Development time and cost were not described as a limiting case by the customer so this is not a problem, however, a plan to raise the manufacturing readiness level should be made.

CRIT-HvsV-07: VAWT can be manufactured from recycled metals increasing sustainability. HAWT can be made of metals, doing so drastically limits blade size. Traditionally HAWTs are made of composites. Based on the trade-off presented in Table 3.2, the choice is clearly in favor of the grouped rotor VAWT.

Table 3.2: *Rotor orientation trade-off*

CRIT-HvsV	**02**	**03**	**04**	**05**	**06**	**07**
Individual VAWT	(L)	(O)	(R)	(G)	(G)	(G)
Individual HAWT	(L)	(O)	(O)	(G)	(G)	(O)
Grouped VAWT	(G)	(G)	(L)	(L)	(L)	(G)

3.2.3. Sensitivity analysis

It can be seen that in the trade-off grouped rotor VAWT outperforms or is equal in every criterion except for manufacturing and technology readiness level. If the design where to have a tight deadline, then individual rotor HAWT design might be considered. However, it was explicitly stated by the customer that a tight deadline is not a user requirement. As a result, grouped rotor VAWT is the best solution.

It is useful to consider assumptions made and how they influence the result. HAWT are more efficient than VAWT (around +6%) [8][19]. The packing ratio makes the HAWT less space efficient than VAWT (around-9%). Generator mass is not perfectly linear with torque, as some components of a generator scale with different factors. If the width of the turbine is not approximately equal to the height, then the number of generator scaling changes. If the height of the turbine is two to four times the rotor diameter, the number of generators becomes comparable between individual rotor HAWT and grouped rotor VAWT.

3.3. Yaw control trade-off

Two types of yawing mechanisms can be identified: passive and active. For an active yawing system, several control surfaces are used in order to move the structure, while for the first one, exclusively the wind force is used to adjust the position of the rotor with respect to the wind direction. A few pros and cons will be listed for both options, and then a decision will be drawn based on them.

The advantage of the active yawing system is the increased amount of energy captured. The energy produced is maximised since the system's orientation is constantly corrected. Secondly, the actuators can play an essential role in wind turbine protection. Depending on the severity of the weather, the turbines might be oriented in such a way that the risk of damage is minimized. A few disadvantages can also be identified. First, such a system usually requires a higher complexity due to multiple components, such as motors, gears and sensors, thus increasing maintenance cost. Furthermore, energy consumption is another factor that needs to be considered. This is reflected in the lower net energy production of the wind turbine.

The passive system is the second design option for yawing. Having a passive system for orientating the structure is simpler and more reliable. This implies possessing fewer components, further translating into higher reliability and lower maintenance costs. The costs for operating, manufacturing and installing such assembly are considerably lower. However, there are a few drawbacks that can be identified. Since no components are actively used, and the body's rotation is only based on the aerodynamic forces, the captured energy's overall efficiency is lowered. Moreover, the control of the turbine is not effective. Passive yawing systems lack the ability to actively respond to sudden changes in wind direction, gusts or oceanic phenomena.

Due to the size and requirements regarding the power density and power produced of the destined offshore wind turbine, it is necessary to equip it with an active yawing system. This can be considered as a final decision for the later design stages. It was evaluated that no trade-off table is needed for this selection since the active yawing control is required. The active yaw system options considered are electric, hydraulic or aerodynamic. Sketches for all options can be found in Figure 3.4, Figure 3.5 and Figure 3.6.

3.3.1. Trade Criteria

In this subsection, the trade-off criteria for the yaw control system are listed, along with their weights. A brief explanation of each of them will be presented.

CRIT-YCT-01 (Weight - 12.5%): Power consumption
CRIT-YCT-02 (Weight - 25%): System complexity
CRIT-YCT-03 (Weight - 18.75%): Response time to yaw
CRIT-YCT-04 (Weight - 31.25%): Maintenance
CRIT-YCT-05 (Weight - 12.5%): Cost

CRIT-YCT-01: This criterion assesses the effect of having a particular type of yawing system on the energy production of the entire turbine. The yawing system also requires a specific amount of energy in order to operate. Consequently, the system will need to take a fraction energy produced by the turbine and deliver it to the actuators. The weight assigned to this criterion is the lowest compared with all the others. The main reason for this is related to the fact that the energy consumed by the types of yawing systems can be considered very small compared to the amount of energy produced by the entire turbine.

CRIT-YCT-02: This criterion assesses the complexity level of the different options. This criterion plays a very important role in the choice of the design option for the yawing system since it will have a large impact on multiple factors such as cost, maintenance, and reliability. For this reason, a pretty high weight was assigned to this criterion, accounting for 25% of the trade-off.

CRIT-YCT-03: This criterion assesses the time the system takes to react to a sudden change of the wind direction. Because the turbine will be exposed to multiple types of weather conditions during its life, the yawing system will need to be reactive to avoid losses in energy production. The weight given is not that significant due to the fact that having a system that is a bit slower in changing attitude will not have a huge effect overall besides a lower efficiency for the time the system takes to rotate.

CRIT-YCT-04: Having a criterion assessing the maintenance side of the yawing system becomes crucial. This criterion as a whole considers different aspects such as sustainability, accessibility of the system, ease of maintenance, how often the system requires maintenance and what type of it. In light of this, the weight assigned to this criterion is the highest.

CRIT-YCT-05: The cost criterion comprises all the effects of the yawing system on the project finances from production to decommissioning. The weight of this criterion is pretty low, mainly because, according to the cost model for this project, having a higher cost of the system would not affect the LCOE much.

3.3.2. Trade-off

CRIT-YCT-01: The power consumption of the electrical yaw control system is notable and is similar to that used by the hydraulic system. Unlike the hydraulic system, the electric system only consumes power when active. The main difference between the hydraulic and electric options is that the former must constantly stay pressurised and not turn off. As such, it is a constant drain on the power produced. The aerodynamic yaw control system does not actively consume power; rather than that, it reduces the power production of the system itself in order to create differential drag. By itself, this does not require additional power infrastructure and systems and just requires some power losses, though they might be compensated for the higher efficiency due to proper yawing.

CRIT-YCT-02: An electrical wake control system requires an electrical motor to yaw. An electrical motor is not a problem in terms of complexity. However, the electric system is not as simple as the aerodynamic yaw control system. The complexity of the hydraulic yaw control system is greater than that of the electrical. This mainly comes from the fact that additional pumps and valve systems are required in order to operate the system. This would also mean that more new sensors are needed to power the system. The complexity of the system itself is rather small compared to the other options, as it only needs a controller to integrate with the power control system. It does not require any other additional actuators, as the power control system needs to be able to control the turbines and determine wind conditions anyway.

CRIT-YCT-03: The response time of the electric system is the lowest, as the electrical motor does not need to ramp up and very quickly produce torque. There is still the matter of ensuring there is sufficient power for it. The response time to yaw is almost on pair with the electrical one. Both respond quickly, as the motors do not need much time to react. The speed and accuracy of the hydraulic are high, just as was the case for the electrical one. The response time of the aerodynamic system will always be the highest due to the fact that in order to generate a yawing moment, the turbines themselves need to be sped up or slowed down, which takes more time than activating an electrical or hydraulic motor.

CRIT-YCT-04: Maintenance of large, bulky electrical motors is relatively easy. Many motors are also available as off-shelf components, so the replacement should be simple. To reduce fatigue and increase reliability, it might be feasible to use an oversized motor. Since the hydraulic yaw control system requires more machinery, which would, in turn, need more control systems and monitoring equipment, the maintenance would be longer and more demanding. The hydraulic system would be the most difficult to maintain out of the three options. The maintenance of the aerodynamic yaw control system is rather simple. Since the only additional equipment is the controller, all other components involved would already be covered by the maintenance of the other systems, although the rotors might experience more loads due to use for yaw control.

CRIT-YCT-05: Electrical motors are readily available, and since there is no requirement for the electrical motor to fit in a small nacelle, the price should not be very high. While it would not be as cheap as using the aerodynamic yaw control system, it would definitely be less pricey than using the hydraulic yaw system. Concerning costs, hydraulic systems tend to be relatively cheap when they can be more bulky. The costs are still higher than the electrical system and are especially notable compared to the aerodynamic system. The aerodynamic control system is the cheapest of the three options. This is mainly due to the fact that no new components will be needed. Along with simple maintenance, this option is the cheapest and most cost-effective.

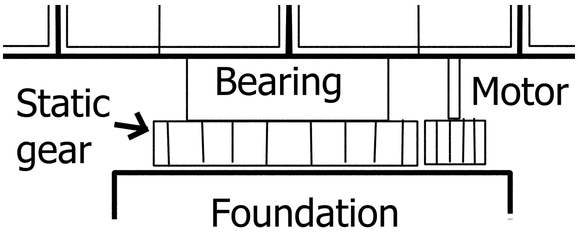


Figure 3.4: *A sketch of the electric motor yaw system*

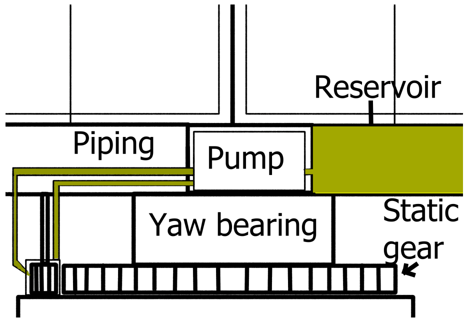
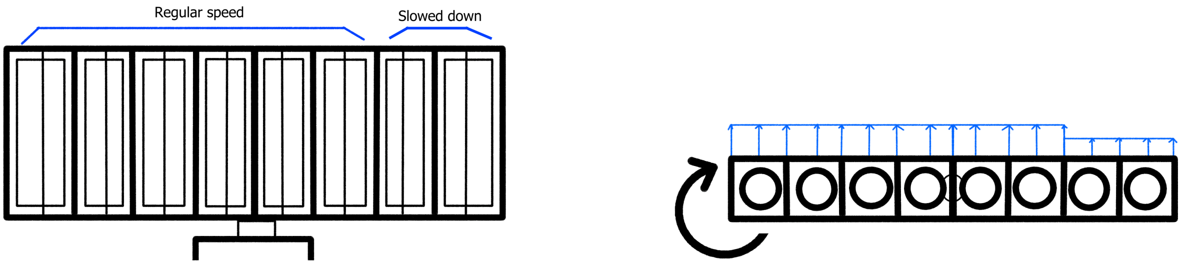


Figure 3.5: *A sketch of the hydraulic yaw system*



(a) *Using differential thrust to yaw by slowing down outside cells*

(b) *A top-down view of the turbine with distributed thrust causing a yaw moment*

Figure 3.6: *A sketch of the aerodynamic yaw system*

Based on the performance of each option, each of the designs was scored based on compliance with each of the five criteria listed. The results of this scoring are presented in Table 3.3. The width of individual columns corresponds to the weight of each criterion.

Table 3.3: *Trade table for the yaw control system choice*

CRIT-YCT	01	02	03	04	05
Electric	(O)	(L)	(G)	(L)	(L)
Hydraulic	(O)	(O)	(L)	(O)	(O)
Aerodynamic	(L)	(G)	(O)	(G)	(G)

The trade table presents the aerodynamic yaw control system as the most feasible option. The electric system comes as the second alternative, mainly being held back by requiring more power and increasing system complexity. Its main advantage is its high precision and the fact that it can be easily turned off or on, which is not the case for the hydraulic system.

An important aspect to consider, though, is that the aerodynamic control system requires the turbines to function. For the multi-rotor turbine, this might only sometimes be the case. For the case when a rotor failure may not yet warrant maintenance, the effectiveness of the yaw system would fall. This could be compensated by including a back-up option along with the aerodynamic system.

3.3.3. Sensitivity Analysis of the Trade-off

The only aspect that could change the outcome of the trade-off is the importance of response time and the power consumption. Should the response time and performance become more important, the trade-off would be in favor of the electric yaw control system. The hydraulic system seems inferior to the electric system considering all five criteria. Considering all that, while aerodynamic YCT is the clear winner, the system should also include an electric system as a backup. With this, the system's reliability is would be higher, at no additional direct cost when switched off.

3.4. Rotor sizing trade-off

Another of the main design choices involves the number of rotors that will be placed in a single structure. This will affect various parameters in the design, including the loads that the support structure will be experiencing, the generator type and mass, and the reliability of the construction as a whole. This will be expanded upon in the criterion.

After the earlier trade-off concerning HAWT and VAWT, the design choices are all VAWT and compare the number of rotors per shaft, the total rotor number and active area of rotors so that the 60 MW requirement is met. As mentioned in Chapter 2, the design options will all follow the same power law as well as having an aspect ratio of 5. In addition to this, sea level conditions in the North Sea will be used for the initial sizing of rotors, with an air density of 1.225 kg/m and rated wind velocity of 11.2 m/s. For initial comparison, a C_p of 0.47 will be assumed, as taken from literature on similar configurations [8]. The considered options are:

1. Large multiple rotors, 1 per shaft
2. Large commercial rotors, 2 per shaft
3. Medium commercial rotors, 3 per shaft

The first design option represents the minimum amount of rotors necessary to satisfy the energy requirements while using the aspect ratio constraint, utilising the entirety of the allowable height. This first design option is both to find the minimum width of the structure as well as to make use of the higher wind speed at the top of the structure due to wind shear. Using Equation 2.31, this design resumes of 10 rotors of 280 m tall by 56 m wide, each on a single shaft, providing 6.34 MW of power each and spanning a width of 560 m.

Secondly a design option where two rotors are fitted to a single shaft is analysed. As with the first design option, the maximum height is utilised. The design resumes to 38 rotors of size 140 m tall by 28 m wide, each supplying 1.59 m of power each, leading to a structure 532 m wide.

The final design option consists of one where three rotors are used per shaft, leading to 86 rotors of size 93 m tall by 18.6 m wide, each providing 699 kW, leading to a total width of 531 m.

As shown by the design criteria, there is a variation of under 31m in the options' total widths. This means that the aspect ratio of the structure is not a function of the number of rotors nor the total area. An important consideration that stems from this is the nature of any wake re-energizing systems that would be placed into the structure, thus meaning that the nature of possible wake structures is not dependent on the changes in the structure supporting the different number of rotors. However, the minimum depth of the structure is dictated by the width of the VAWT. This is a minimum value that may not be the final size and may be added to in order to minimise the material costs and masses, as shown in [8].

It is important to note that this trade-off will not set the final number of rotors nor the final aspect ratio but instead provide a base number for the conceptual design that can be deviated from, as well as the number of rotors per shaft.

3.4.1. Criteria and Weights

Based on the analysis, several criteria have been established:

CRIT-RSIZ-01: (Weight 10%) Summed mass of Rotor Nacelle Assemblies (RNA)
CRIT-RSIZ-02: (Weight 15%) Summed cost of RNA installation and parts
CRIT-RSIZ-03: (Weight 20%) Reliability of design option
CRIT-RSIZ-04: (Weight 25%) Ease of Maintenance and accessibility of design option
CRIT-RSIZ-05: (Weight 20%) Possible suppliers and manufacturers
CRIT-RSIZ-06: (Weight 10%) Stacking effects

CRIT-RSIZ-01: This criterion was chosen for its effect on the turbine structure. By increasing the mass of the turbines, the generators, and the rest of the nacelle assembly, the gravitational loads increase. This is particularly affected by the mass of generators. In section Subsection 2.4.1, it is shown that the model used for individual generator mass scales with torque Equation 3.1.

$$M_g \propto T = \frac{P_g R}{v_{inf}\lambda} \tag{3.1}$$

Thus individual generator mass scales with $P_g R$ (k_{pac} is assumed constant for trade-off purposes), and it was shown that for a given range of Reynolds number, radius scales with $\sqrt{P}$. Since number of generators scales with P^{-1} this means that total generator mass scales with $M_g n \propto = P_g^{1/2}$

The rotor size increase also causes an increase in mass; specifically, the radius increase causes an increase in swept area and volume. Ignoring rotor design techniques, mass initially scales with volume. When refining the design, scaling techniques come into effect, and this is no longer the case, as larger designs will not have the same internal structure as smaller designs. However, it is still a factor that increases with the power of the individual turbines.

CRIT-RSIZ-02: This criterion is relevant to the requirement of a decrease in LCOE. It is important to remember that manufacturing large blades is currently only done by a few manufacturers, namely Siemens, General Electric, and Vestus, along with a few others. On the other hand, smaller blades have many more OEMs. Additionally producers in other fields, such as aircraft wing manufacturers, could join in production. While this is an argument for smaller turbines, the rotors are not a major part of the cost, compared to the rest of the RNA, mainly the generator and the nacelle.

Generators and ancillary components (platform, drive train, converter, etc.) follow a power scaling law [20], becoming more expensive with increasing power and torque requirements. However, by using smaller generators and rotors, costs can be lowered on the basis on economies of scale formanufacturing, as multiple OEMs could be contracted. Furthermore, transporting and installing smaller parts require light duty cranes and simplify transportation. Moreover, larger rotors would lead to fewer connection points to the structure, thus increasing stress at connectors, and inadvertently increasing structure cost. Yet, it is shown via analysis of current wind turbines [21] that the cost of the structure is a minor part of the total cost. Thus, the increase in structure needed by increasing the number of shafts and the number of rotors is a minor increase in cost.

CRIT-RSIZ-03: This criterion regards the necessity and rate of maintenance, as well as overall reliability. Having more numerous RNA's will lead to an overall increase in components, and thus, in the number of points of failure. However, each failure causes a smaller percentage loss of power. In addtion to this, as noted in the article by Jamieson et al., having a higher number of smaller rotor enables the addition of redundant rotor at a lower cost.

In addition to the rotors, the aerodynamic yaw system is also given redundancies, as this system has a high failure rate [22]. This allows for more severe faults to occur without having to make unscheduled maintenance by switching to redundant rotors in order to maintain power generation and yaw functionality[8].

By purely using the definition of a failure by Carroll et al.:' a visit to a turbine, outside of a scheduled operation, in which material is consumed[22]' the option with the longest time between unscheduled maintenance is to increase the number of rotors ad infinitum so that the highest number of faults without significant decrease in power generation rises with it. However, this has significant downsides. When scheduled maintenance must be done (as the following criterion will discuss) and when the faults must be fixed, this becomes a much longer and, thus, more expensive procedure, especially for the design option with the most wind turbines.

This highlights the two sides of the reliability criterion. One one side increasing complexity leads to lower reliability. On the other hand numerous components lead to higher redundancy and lower power losses due to downtime.

CRIT-RSIZ-04: This criterion focuses on the ease of scheduled maintenance. As mentioned earlier, fewer rotors means fewer points of failure and fewer required maintenance points. Yet, even if maintenance and accessibility of ancillary elements is eased in the case of fewer bigger rotors thanks to the simplicity of the structure, the maintenance of the rotor itself could prove troublesome due to its sheer size. Additionally, in the case of big rotors the pitching system might also prove problematic due to the high loads needed to be carried. In addition, the necessity of having a more complex structure due to having more turbines leads to the possibility of implementing more maintenance access structures throughout, mainly by having more climbable structures and more sensors. This leads to a simpler maintenance process, leading to lower maintenance costs. Once again, this increase in maintenance performance is weighed against the larger number of systems that must be maintained, as the increase in systems will also increase the time required for maintenance. However, due to the aforementioned benefits of complex structures, the two effects partially counteract each other.

In addition to this, the required process for replacing or repairing various components is highly dependent on their size. Specifically for replacement: the larger and heavier the components, the more complex machinery, and the higher cost is required for repair. This is a severe disadvantage for the largest turbines especially due to their relative importance to the total power generation.

CRIT-RSIZ-05: This criterion focuses on the possibility of contracting multiple smaller OEMs. As mentioned in the cost criterion, the larger the rotors, the fewer manufacturers are currently available for rotor production. The centralisation of producers leads to larger transport times and costs. Additionally smaller rotors could be acquired by smaller, local OEMs. This also allows for both sharing risks and decreasing (non-value) transportation times. Using more OEMs has the added effect of spreading the manufacturing among multiple companies to minimise the manufacturing time, leading to faster installation times and lower costs.

Another benefit of having local manufacturing companies is the increase in sustainability. This includes both environmental sustainability, due to the decreased emissions from transport over shorter distances, as well as economic and social sustainability by supporting local businesses. A caveat to having more manufacturers, however, is the necessity of more stringent quality assurance to ensure all of the products received are of the necessary quality.

It is important to note that currently large VAWT manufacturers do not exist. Yet, it is assumed that the same companies currently producing large HAWT would be able to begin manufacturing VAWT of the same scale

CRIT-RSIZ-06: This criterion deals with the loading considerations and effects the rotor configuration has on both the structure and the generators, specifically focusing on with three main effects: vibrations, fatigue, and torque delivery.

When increasing the number of rotors, it is clear that the loading on the support structure would change to reflect the increase in connection points at the shafts of the rotors. While the general increase in mass that would result from this is already taken care of by earlier criteria, the specifics of the loading effects still need to be determined. In particular, the effect of the increase in the dangers of vibrations from the loading must be determined. Due to the wind's inconsistent force throughout the structure, mainly because of wind shear making the wind lower down slower than that higher up, the higher the number of rotors, the more numerous the vibration loads. This means that a more robust structure is necessary, along with more maintenance and care taken for monitoring the structure's fatigue. All of which lead to higher costs and lower lifetime for the components involved.

In addition, a point of importance is that when multiple rotors are placed on top of each other, they can be placed at angles with respect to each other to provide smoother torque to the generators and increase their effectiveness [8]. This benefit is only available when more than one rotor is placed on each shaft.

It is also important to remember that since all design options span the entirety of the height available that the stress of the difference in torque is either directed into the shaft and thus the generator and structure below or into the rotor itself, leading to more wear of the rotor.

Weight analysis

The weights given reflect the relative importance of each criterion on other systems as well as on the requirements they are supporting themselves. After closer analysis, the following was decided: the most important factor the number of turbines has on the design is the effects on maintenance and reliability. This is where the largest changes in cost, time investment, ease of usage, and implementation are found. In this case, specifically, reliability takes precedence over maintenance ease and access. This is because with a relative increase in reliability comes a change in the necessary maintenance. After this, the number of manufacturers takes precedence over cost and the rest of the criteria since they are all at least partially affected by the manufacturing process and available options of this. After this, the cost criterion is deemed the most important, as the structure of the turbine is relatively cheap compared to the maintenance and installation costs meaning that the number of generators and other components is of higher importance.

This leaves the mass of the RNA and the vibration and fatigue effects to have the same weight. Mass has the lowest relative weight because the structural consideration necessary to account for the mass increase mainly leads to a more complex design and higher costs. In this respect, the higher costs are a minor increase in the overall cost of the design as can be seen in the cost breakdown, while the actual design work needed to account for the extra mass just narrow the design space of the project. Finally, the vibration and fatigue effects have a lower weight since the main effect of the criteria considerations is a combination of an increase in costs for a more stable structure, which has already been mentioned to be of lesser relative importance, and an effect in increasing the necessity of maintenance and decreasing lifetime, which also has larger contributions from the implementation in the number of rotors. Most of the effects can be mitigated by increased detail in the structure and maintenance, which already have their own criteria, so the remaining central effect is left to be the mitigated decrease in performance. Thus it is left to be the lowest weight criterion along with the mass.

Table 3.6 shows the final trade-off table. The table shows that the best option is having two rotors per shaft.

Table 3.4: *Trade table for the choice of rotor number*

CRIT-RSIZ	01	02	03	04	05	06
1 per shaft	(O)	(O)	(G)	(G)	(O)	(L)
2 per shaft	(L)	(L)	(L)	(O)	(G)	(G)
3 per shaft	(G)	(G)	(R)	(R)	(G)	(R)

From this table the best option is 2 rotors per shaft. This has the best shaft effects and a high amount of suppliers while also being a decent sot and mass option. The only drawback is the amount of components to maintain but this is still within acceptable bounds and counteracted by the higher reliability

3.4.2. Sensitivity Analysis

Sensitivity analysis shows that a single rotor per shaft is the preferred option if the manufacturing criterion is ignored. Meaning that the single rotor per shaft is the second best option.After analysis, the option with three rotors per shaft has too many drawbacks in the shaft effects and too many components to maintain.

3.5. Foundation trade-off

The turbine design can use either a monopile or a floating foundation. Both options have been used in the past, though neither has been used for a system of such scale. A central bearing would be required for both the fixed and floating foundations to yaw the system. As such, the choice of the foundation would, in both cases, be attached to the tower by a central bearing.

The monopile design would involve a massive rigid support structure, which would serve as the base of the bearing. The design option tree also included the option of using a truss structure as a solid foundation. These are currently used in cases where the water depth is too large to use a traditional solid monopile (depths up to 70 m [23]). Yet, the system is intended for installation sites where a monopile would be an option, so the truss structure is not considered. The floater option is as described in Table 2.3.

3.5.1. Trade Criteria

Trade-offs between the fixed and floating foundations are based on the system's requirements. They aim to make the system as suitable as possible while staying within the constraints of the budgets and requirements. The most important criteria for the foundation were listed below, along with their weights.

CRIT-FND-01 (Weight - 29 %): Structural mass and material choice
CRIT-FND-02 (Weight - 12 %): Maintainability
CRIT-FND-03 (Weight - 29 %): Lifetime operations
CRIT-FND-04 (Weight - 18 %): Ecological impact on marine life
CRIT-FND-05 (Weight - 12 %): Usable depth

The description and justification for each of the criteria are presented below. Alongside an explanation of why these weights were chosen, there is also a justification for the importance awarded to each criterion.

CRIT-FND-01: The structure's mass and material selection are essential for the foundation, as it is included in the levelised cost of electricity. A large mass and specialized materials also reduce possibilities for the democratization of production, as it would limit the range of possible suppliers.

CRIT-FND-02: For wind turbine operation, system maintenance costs play a significant role in the LCOE. It is crucial that the foundation can be easily repaired, inspected, and maintained.

CRIT-FND-03: Lifetime considerations of the foundation involve two main categories: installation and end-of-life. The installation of the foundation will have a direct impact on the marine environment where the system will be installed. It is also likely to be an important driver for the costs of the foundation system after production. The ease of installation of the other subsystems is also considered. As the system aims to be sustainable, it is also important to consider the end-of-life of the foundation. This involves the possibilities of re-use of the foundation, the possibilities for life extensions, and removal procedures/costs.

CRIT-FND-04: Since the foundation is mostly submerged, it will be part of the system with a constant effect on marine life. It is vital to consider this in the decision between the different types of wind turbines.

CRIT-FND-05: System usable depth is considered. Northern Sea under the jurisdiction of the Netherlands is mostly shallower than 50 m so the foundation should be able to reach at least that depth. Going deeper would be a potential benefit allowing for installation in other locations.

3.5.2. Trade-off

CRIT-FND-01: Fixed foundation mass of the monopile was estimated using historical data in combination with preliminary estimates for the axial compression and bending moments described in section 2.4.4. The total mass of the monopile was thus estimated to be close to 5512 t. As mentioned, this assumes that the monopile has a constant diameter throughout its length. Regarding the floating option, the total mass of the floater was thus estimated to be 9742 t. This is over 15 times more than the monopile. Additionally, the floater's height is estimated to be roughly 25 m. This larger weight means that it would be heavier and the material costs would be much more expensive.

CRIT-FND-02: Maintenance of the monopile is simpler, as it is essentially a vertical cylinder manufactured from steel. It does not move and has a relatively low surface area, the inspection is simple but time-consuming. Maintenance of a floater is more complicated than a monopile, as it is expected to have a much larger size. A larger surface area must be inspected. While it does not reach the ocean floor, the sheer size means that maintenance is likely going to be more difficult than for the monopile. Since it is a floating structure, it could theoretically also be towed offshore for easier maintenance.

CRIT-FND-03: Installation of a monopile is more complicated than the floaters. Piling requires specialised jack-up vessels for beam orientation, from horizontal to vertical, and hammering. Scour protection after installation needs to be applied resulting in extra costs and delays, therefore, is a risk factor. In Germany, sound exposure is regulated via law for a single-stroke sound exposure level (SELSS) of 160 dB at a distance of 750m to the construction. This norm is stricter than the one applied in the Netherlands, the system is designed to be compatible with all North Sea economic zone regulations. This level can be achieved using existing mitigation techniques which will be explained further in the report [24].

A monopile may be reused if its lifetime is extended. Otherwise, it may be removed from the seabed entirely, or a part of it can be left embedded in the ocean floor. Removing it entirely may incur additional costs for the design while leaving it behind would mean the seabed can't be reused for another system. Either way, using a monopile implies that there will be significant cleanup costs. Installation of the floater itself is rather simple. It can be assembled at the shore and then transported there by ships. A floater would be very large compared to existing options. As a floating system, a floater would be simple to remove, relative to a monopile. After removing the individual anchoring cables, the floater could be towed away to the shore after the end of its life. Its lifetime could also be extended.

CRIT-FND-04: A monopile has a significant impact on marine life. The structure goes from the seabed to the surface, meaning that sea life encounters an occur at any depth. While it provides a habitat for some organisms, such as barnacles, it would be disruptive to fish and mammals. The floater would have a much larger surface area than a monopile. The floaters would not reach as deeply as the monopile, thus not disrupting marine life close to the ocean floor. Due to the floaters' large size, they could be a habitat for more animals, including birds.

CRIT-FND-05: Monpiles are claimed to be feasible for usage at depths up to 70 m [23]. This is more than any areas with wind farms planned by the Dutch government[1]. Floaters can be used at much larger depths than monopiles. This is not the most relevant when it comes to the Northern Sea, but it would expand the possible locations, where the system could be installed.Table 3.5

[1] https://north-sea-energy.eu/en/energy-atlas/

Table 3.5: *Foundation trade-off.*

CRIT-FND	01	02	03	04	05
Floating	(R)	(O)	(G)	(L)	(G)
Fixed	(L)	(L)	(O)	(O)	(L)

Based on the trade-off presented in Table 3.5, the choice clearly favours the fixed foundation. The sheer size of the floating foundation makes it unfeasible to use under the current requirements. In 2016 80% of all offshore wind turbines employed the monopile for their foundation [15], meaning that the trade-off was in favour of the most commonly employed option. Since the floating foundation is not beneficial in shallower water, where the monopile can be used, it does not seem logical to consider the hybrid options, since it would add more weight, which was one of the advantages of the monopile, while not improving the environmental impact, which was the floaters strong suit. It would also be just as limited as the monopile.

3.5.3. Sensitivity Analysis of the Trade-off

The trade-off is highly sensitive to criterion **CRIT-FND-05**. This is tightly linked to the installation sites for the system itself. Should the depth requirement for the system installation increase past 70 m, the monopile becomes completely unfeasible since it simply can not be installed at such depth. While the mass of the floating foundation is enormous, it would be the only possible option for a depth of more than 70 m. If the maintenance costs need to be minimised, the floating design becomes even less feasible. Due to its sheer size, the maintenance costs would be much larger, and the time needed for inspection and repairs would take even longer. Lastly, if even more consideration would be given to the impact on the environment and wildlife, then the criteria **CRIT-FND-03** and **CRIT-FND-04** would become main drivers for the trade-off, which would make the floating foundation more appealing, due to the ease of installation, disposal, and lesser impact on the marine life. Overall, the trade-off result would change if the required depth requirement increases past 70 m, or if the environmental impact became a lot more important and requirements a lot more strict, while the importance of mass of the structure diminished.

3.6. Drive train trade-off

Within the selection of a design for the drive train, several design options were discovered after the baseline report. Thus, a new trade-off is necessary to evaluate the four identified design options for the drive train sub-system. These options are:

1. Direct drive with a permanent magnet synchronous generator (DD-PMSG) and a full converter
2. Direct drive with an electrically excited synchronous generator (EESG) and a full converter
3. Drive train with a gearbox, a doubly fed induction generator (DFIG) and a partial converter
4. Drive train with a gearbox, a permanent magnet synchronous generator and full converter (PMSG)

The first two design options follow a similar design pattern, having the shaft connected to the rotor directly linked to the generator element. In order to match the frequency of the grid, either 50 Hz or 60 Hz, depending on the installation region, a full converter is included. The other two design options use a gearbox between the rotor and the generator. Usually, a planetary gearbox, comprising of either two or three stages, is considered to bring the rotational velocity of the drive shaft within the operational RPM window of the generator. The doubly fed induction generator of design option 3 incorporates a partial converter, which can vary the current frequency to the generator's rotor making it operable with variable rotational speeds[25]. Below in Figure 3.8, a simple block diagram of the electronic components is shown.

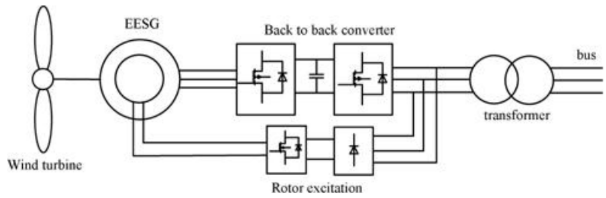


Figure 3.7: *Schematic of a drive train using an EESG configuration as prescribed by design option 2 [26]*

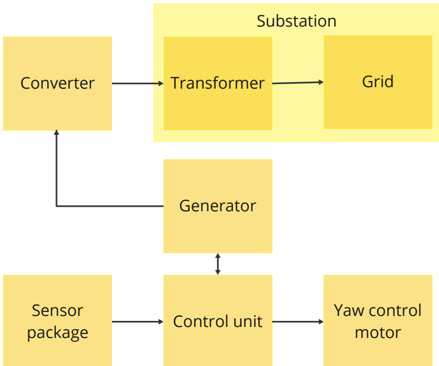


Figure 3.8: *Block diagram of the electronics present*

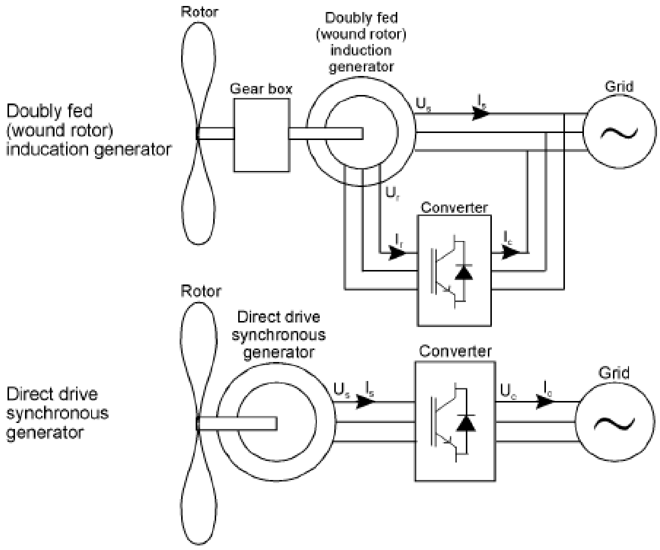


Figure 3.9: *Schematic of a DFIG drive train as described by design option 3 (upper image) and of a direct drive PMG drive train similar to design option 1 (lower image)[27]*

3.6.1. Criteria & Weights

Design options are graded on the five criteria with a given weight listed below.

CRIT-DRT-01 (Weight - 25 %): Availability
CRIT-DRT-02 (Weight - 20 %): Cost
CRIT-DRT-03 (Weight - 25 %): Sustainability
CRIT-DRT-04 (Weight - 15 %): Manufacturing democratization
CRIT-DRT-05 (Weight - 5 %): Power - mass density
CRIT-DRT-06 (Weight - 10 %): Power efficiency

CRIT-DRT-01: Availability has the highest trade-off weight at 5/5, as it is directly linked to the operational cost of the system. It incorporates the reliability of the generator, as well as its maintainability. A lower availability indicates a lower downtime and thus, a lower production loss. Downtime is also related to repair costs, as lengthy repairs are typically more expensive.

CRIT-DRT-02: According to Catapult, the cost of a generator and gearbox is 7.17% of a wind turbine's CAPEX cost, which means that drive train cost is directly responsible for a large fraction of the LCOE [21]. As lowering the LCOE is one of our driving requirements, this criterion has a trade-off weight of 4/5.

CRIT-DRT-03: Generators' sustainability refers to using rare-earth metals for permanent magnets. With the explosive growth of wind energy generators, demand for these metals is expected to rise to 13-31x of the current demand (depending on the specific metal). The world supply of these materials is limited, with China being responsible for 80% of the worldwide production [28, 29].

CRIT-DRT-04: Manufacturing democratisation measures how common a drive train system is, how many companies can supply them, and whether existing off-the-shelf generators can be used. Low manufacturing democratisation leads to higher development costs and fewer companies to work with.

CRIT-DRT-05: The power density of the generator directly influences the mass of individual generators in the system for a specific power output. Lower power density, and therefore higher generator mass, is disadvantageous, as the structure will need to be stronger to support it. However, given that the main influence on the overall design will be a slightly higher structural mass, and the total cost of the steel for the structure is only 2.5 % of the total CAPEX cost [2] ,this criterion's importance is relatively minor compared to the other criteria. The trade-off weight is, therefore only 1/5.

CRIT-DRT-06: The electrical efficiency of a drive train dictates power losses and, therefore, directly influences the LCEO. However, as the differences in drive train systems are not that large, the differences in efficiency are given a low trade-off weight of 2/5.

3.6.2. Trade-off

CRIT-DRT-01: According to El-Metwally et al., the DD-EESG generator has low availability, and the DFIG generator has intermediate availability [30]. Carroll et al. indicates that turbines with PMSGs have a higher availability than DFIG-based turbines, with direct-drive PMSGs having the highest availability, followed by geared PMSGs [31].

CRIT-DRT-02: Pavel et al. compares the costs of the same four drive train types as this trade-off and shows that geared systems are cheaper than direct-drive systems, with DFIG being the cheapest system, followed by G-PMSG, DD-PMSG, and finally DD-EESG. According to Polinder et al., the cost of a DFIG drivetrain with a 3-stage gearbox is 1.87 M€, a DD-EESG 2.12 M€, a DD-PMSG 1.98 M€, and a PMSG with a 1-stage gearbox 1.83 M€ for a 3 MW system [33]. The cost of the DD-EESG system is almost 16% more expensive than the geared PMSG drive train, a relatively large increase in cost.

CRIT-DRT-03: Li et al. provides an overview of the average amount of rare-earth metals used for different types of generators. DFIGs do not use any rare-earth metals and are therefore the most sustainable generator type. DD-EESGs and G-PMSGs use a moderate amount of rare-earth metals, with 30 and 52 tons/GW respectively. DD-PMSGs are by far the most unsustainable option, with an average rare-earth metal use of 231 tons/GW [28].

CRIT-DRT-04: According to Pavel et al., 77% of the current global wind energy capacity uses electromagnetic generators, with the remaining 23% using permanent magnet generators [32]. The direct drive generators require the generator to be matched to the specific RPM of the turbine. As the rotors in this Table 3.2 are relatively unconventional, direct-drive generators would not be widely available. The use of rare-earth metals is deemed a disadvantage, as the uneven world supply poses a risk to the supply chain.

CRIT-DRT-05: Due to the use of permanent magnets which do not require sub-assemblies for powering or cooling, unlike the EESG and DFIG options, it is clear that the design options that include PMSGs perform best from the point of view of power density. In fact, this is one of the most repeated advantages in literature of PMGs, and one of the fundamental reasons why it is heavily used in the offshore market [34]. Adding a three-phase gearbox to the design should add to the weight of the subsystem, but literature shows that incorporating a gearbox leads to a reduction in the weight of the generator itself [28]. The DFIG has seen wide use for small and medium wind turbines with rated power lower than 5 MW [32]. This led to optimising the design option, leading to increases in power density, although not quite matching the performance of the PMSG. Lastly, the EESG has not been considered for offshore applications due to its increased weight [32]. Additionally, due to the large amount of copper used for the electromagnet, the power density of the generator is lower than for the other design options [34].

[2]Catapult https://guidetoanoffshorewindfarm.com/wind-farm-costs (visited 05-2023

CRIT-DRT-06: It is broadly accepted that the generator with the highest power efficiency is the PMG due to its use of permanent magnets [35]. Additionally, the high efficiency, of around 95 %, is mostly maintained across the spectrum of variable wind speeds that a wind turbine will encounter during its lifetime, leading to maximum usage of the wind resource and maximum annual energy production. Thus, the direct drive PMG option is rated the highest in this bracket. Adding a gearbox element to the drive train will further lower the efficiency of the subsystem due to increased mechanical losses. From the literature, it is gathered that a geared configuration of the PMG drive train incorporates a three-phase planetary gearbox, and given that the power losses of gearboxes are proportional to the number of phases, it is clear that this design option performs lower than its direct-drive alternative [35],[36]. The direct drive EESG also benefits from the lack of a gearbox, but its electromagnet requires energy from the grid, which also implies the use of another converter to be added to the drive train for powering the rotor. Thus, it is assumed that the EESG configuration needs special considerations. The DFIG configuration also needs power for its induction magnet, and considering that a 3-phase planetary gearbox is required, this option's efficiency is expected to be the lowest of all. Literature confirms this, giving overall efficiency around 90% [35].

Table 3.6: *Drive train trade-off*

CRIT-DRT	01	02	03	04	05	06
DDPMSG	(G)	(L)	(R)	(R)	(G)	(G)
DDEESG	(O)	(O)	(O)	(O)	(R)	(L)
3GDFIG	(O)	(G)	(G)	(G)	(L)	(O)
GPMSG	(L)	(G)	(O)	(L)	(G)	(L)

From the summary table depicted in table 3.6 it is not clearly observable which design option has the overall best performance. Two options, namely the direct drive permanent magnet and the direct drive electrically excited generator, can be easily dismissed based on their performance regarding sustainability and ease of manufacture for small and medium OEMs. Yet, two options remain for consideration, the three-phase geared doubly fed induction generator and the geared permanent magnet drive trains. Yet, considering the importance of sustainability, especially regarding rare earth metals that go into making the permanent magnets, to the client of this design exercise, it can be argued that the DFIG option is superior. Moreover, considering that 80% of the rare earth metals currently used in the wind energy industry are supplied from China, there lies a critical bottleneck in the supply chain, which can raise the potential risk of supply disruptions and spikes in prices, as seen at the beginning of the Covid-19 pandemic [3] [29]. For these reasons, the 3G DFIG configuration has been selected as the drive train option to be used.

3.6.3. Sensitivity analysis

Suppose the focus would change from sustainability and democratisation of manufacturing towards better performance, either by giving more importance to availability or power efficiency. In that case, the design option that includes the three-phase gearbox with the doubly fed induction generator does not present itself as the best option. If the weights of criteria **CRIT-DRT-06** (power efficiency) and **CRIT-DRT-01** (availability) were to be increased and the criteria **CRIT-DRT-04** (manufacturing democratisation) and **CRIT-DRT-03** (sustainability) were to decrease, it is clear that a permanent magnet configuration would be the option to choose. If the client opts for eliminating **CRIT-DRT-04** (market democratisation) and choose to rely on the big drive train manufacturers in the wind industry, then the best configuration would be the direct drive permanent magnet configuration, as common as it is on the market already.

[3] URL: `https://strategicmetalsinvest.com/5-year-prices/` [cited 17 May 2023]

4

Operation and Logistics Concept

The purpose of this chapter is to outline the operation and maintenance strategies, along with the logistics strategy for the conceptual design. As one of the main advantages of the MR-VAWT system is lower expected maintenance costs and easier operations, maintenance is of great importance for the design overall and is one of the key design drivers.

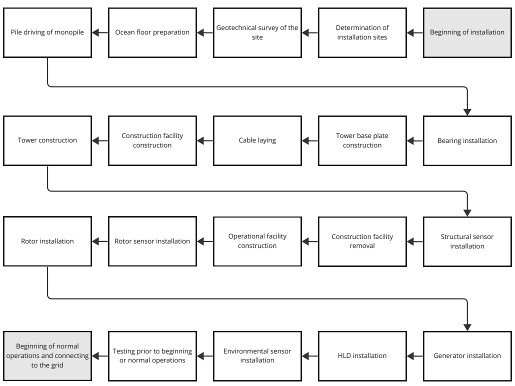
4.1. Operation strategy

This section describes the operations plan for the conceptual design of the system. It mostly focuses on the installation and decommissioning of the system, as maintenance is the focus of Section 4.2. The system's operations are not expected to be much different from the offshore operations of current systems. This would mean that an onshore control center is used for most of the operations, with a small support crew on the wind farm site to allow for quick repair.

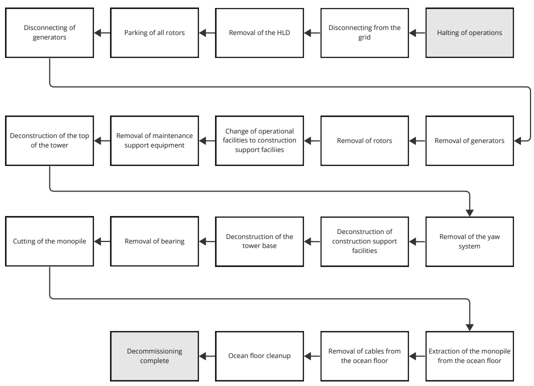
4.1.1. Installation and Decommissioning

The turbine operations will begin with the installation. This is presented in the block flow diagram in Figure 4.1a. This procedure begins quite similar to that of the traditional wind turbine. It begins with the determination of the potential sites and the surveying of the site. After that, the installation of the monopile would be performed. With the monopile in place, the tower base could be constructed. Since the conceptual design includes a very wide, large base, it would be useful to take advantage of it during construction, where it could function as a platform for housing construction workers/engineers and storing parts. This would eliminate the need for big construction ships and reduction of construction costs. Using it as a base for the construction of the truss structure and scaffolding. Any structural measurement sensors could also be installed during the tower's construction.

After the tower's construction, the rest of the elements can be installed on the frame. The construction facilities can be removed to make space for the operations and maintenance support structures on the base plate. With that, the rotors and their sensors can be installed, followed by generators. After generators, the only major system remaining is the HLD, and this could be installed as the last element. With the assembly finished, the system should be tested and then started.



(a) *Block flow diagram of the conceptual installation procedure*



(b) *Block flow diagram of the conceptual decommission procedure*

Figure 4.1: *BFDs for the conceptual installation and decommission*

The decommissioning procedure would be similar to the installation procedure, presented in Figure 4.1b. After disconnecting from the grid and removing the HDL, all the rotors would be parked, allowing generators to be removed. After generators, the rotors and the support facilities could be repurposed for (de)construction support. The structure would then be disassembled from the top down, and the yaw system would be fixed, disabled, and removed. Following that, the support facilities on the bottom platform would be removed, and the tower base, along with the bearing, would be removed until the monopile is the only remaining part. The monopile would then be cut and pulled from the ocean floor. The last step would be the removal of cables and cleaning up the ocean floor.

4.1.2. Nominal Operations

While the system is operating nominally, the system should communicate with the central control station, as is typical for a wind turbine that is a part of the wind farm. As such, the turbine should communicate its current status and operations to it often. Along with that, the turbine should communicate any sensor readings to the control station in order to allow for system health monitoring. This would allow for more adaptive maintenance scheduling, along with the prediction of failures. There should also be a smaller, more local station at the wind farm to allow for fast small-scale repairs. The system should operate nominally on its own without much interference. Involvement from the operators would mainly come into play for system maintenance and repairs. This is further detailed in Section 4.2.

To facilitate maintenance better, the system is designed with all the generators on the tower's base plate. This means that the work generators or their gearboxes can be accomplished more easily, as they do not require workers to ascend a tall tower the way they have to with HAWT systems. Since the base plate of the system is very large, it should also be possible to use physically large, bulky generators instead of the more compact ones employed by HAWT systems. This would make inspection easier and faster.

For safety reasons, the base plate of the tower should be at an appropriate height to avoid extreme wave heights, with an appropriate safety railing to allow safe use since maintenance should also be carried out on the bearings and rotors, as well as the HLD. The truss tower structure lends itself to very convenient support for elevators and walkways with guard rails to allow access for maintenance. This is done in order to allow for much easier maintenance and day-to-day operations.

4.2. Maintenance strategy

Four main maintenance strategies exist for offshore wind turbines. An extensive overview was given by Ren et al., where four main strategies are listed. Their advantages and drawbacks are presented in Table 4.1, where the colour scheme from the Chapter 3 is used, however unlike there, the width of the individual table columns does **not** reflect their relative weights. The four strategies considered are: corrective maintenance, preventive maintenance, conditions-based maintenance, and predictive maintenance.

Corrective maintenance is the simplest option. Adopting this strategy means that maintenance would be carried out once the failure occurs. This allows the maintainers to avoid unnecessary maintenance visits, as they only occur when necessary. However, with this strategy, downtime is very significant, so a system with significant downtime would suffer more.

Rather than waiting for system failure like with corrective maintenance, when adopting a preventive maintenance strategy, maintenance is to be carried out either after a set period of time after the last visit or when the power production has reached a low enough level. This requires minimum costs for monitoring of the system and removes the need for unplanned maintenance visits, but risks unnecessary visits before they would be necessary.

By using sensors, a conditions-based maintenance strategy can be implemented. Sensor measurements and reliability models can determine the degree of deterioration, and this can then be fed into an online or offline monitoring system. By identifying the level of deterioration and the overall health of different components, normal maintenance visits can additionally take care of repairing or replacing parts before they need repair. That way the maintenance visits can be more effective.

A predictive maintenance strategy takes this idea even further. By using even more autonomous conditions and health monitoring, maintenance visits are planned entirely around the state of the system's components. This method aims to reduce downtime and operational costs as much as possible. The downside is the initial investment for all the necessary sensors and the higher degree of automation required.

Table 4.1: *Comparison of different maintenance strategies*

Strategy	Initial costs	Operational costs	Unnecessary visits	Unplanned maintenance	Downtime	Required automation
Corrective	(G)	(R)	(R)	(G)	(R)	(G)
Preventive	(L)	(O)	(O)	(G)	(O)	(L)
Conditions-based	(O)	(O)	(G)	(R)	(O)	(O)
Predictive	(O)	(G)	(L)	(L)	(G)	(O)

As can be seen from Table 4.1, predictive maintenance allows for the lowest operational costs and downtime, both of which lower the LCOE for the design. While there is a larger initial cost and a high degree of automation required, this seems like a worthwhile investment for the design of this scale.

Since monitoring the system's health is of great importance, it should be given even more consideration. Further sensors required by the individual subsystems (FND, TWR, YCT, PCT, WCT, DRT, RTR, and OCT) are presented below.

FND: Foundation health would require sensors to determine the progress of corrosion and any structural damage. This would most simply be done via visual inspection of the monopile by means of a small portable underwater drone. Since the inspection would likely not need to be done very often, only a few would likely suffice for an entire wind farm. However, since corrosion can cause critical faults in the foundation, more detailed sensors will also be discussed in more detail when undergoing the detailed design.

TWR: Tower will be, by far, physically the largest part of the system. As such, inspection will be the most time-consuming. In order to reduce operation and maintenance costs, visual inspection could be done using flying drones. This would make the inspection safer and faster. Since the turbine will have a large, solid base plate, the storage and maintenance of the drones themselves should be relatively easy. Another technique for inspection, which may be carried out autonomously, might be alternating current field measurement (ACFM) since the tower's structure will likely be steel. This method can be applied through paint and coatings. Additionally, thermal imaging systems could be installed on the system in order to allow remote thermography. The option of mounting thermography equipment on remotely controlled drones should also be considered.

YCT: For the yaw control system, the status of the bearing and the motor would need to be monitored. For motor, routine inspection should be enough, provided an oversized, bulky machine is used. This will likely be the case, given that the motor may be mounted on the base plate, where there should be enough space for that. For the bearing, oil and temperature sensors, along with some strain gauges would be necessary. Depending on the size, options for manual or autonomous visual inspection would also be needed.

PCT: Power system requires to have specific sensors, since failure of power control system could result in faults in the generator or rotor subsystems. The type of sensors used are generally electronic, monitoring voltage, frequency and current at strategic places along the power lines and cables. As the system incorporated DFIG, the slip can be varied in order to accommodate for maximum power production in case of unexpected gusts, so sensors which communicate with rotor RPM sensors are needed for determining the slip of the generator.

WCT: For wake control, maintenance and repairs would be the most expensive, as it is located at the very top of the main structure. As such, drones should be used for visual inspection and other methods of non-destructive testing. It may also be useful to have some strain gauges at critical parts in order to determine precisely what loads it was subject to in order to implement the predictive maintenance strategy.

DRT: As the drive train includes the low and high rotation shafts, a three phase gearbox, a DFIG and a partial converter, a large swath of sensors are used in order to verify the power conversion from mechanical to electrical. These sensors include and are not limited to: angular sensors and accelerometers positioned in both radial and axial orientations to monitor the vibrations and movement on the critical moving parts, such as shafts and ring gears, oil sensors for detecting particulate concentration within the gearbox, temperature gauges positioned at strategic points in the gearbox and the generator, Fibre Bragg Gratings (FBG) orientated both in radial and axial directions to monitor loads on shafts and humidity sensors strategically placed in order to estimate corrosion. In addition to these permanent placed sensors other NDT methods that need special equipment could be employed.

RTR: For the rotor, strain gauges at the structurally important joints would be required to determine how soon they should be replaced. The shaft should incorporate RPM sensors in order to precisely determine the rotation of the rotor, alongside transducers that can monitor the torque the rotor is outputting. The blades would also need to be routinely inspected, as the harsh marine conditions would likely cause severe leading-edge corrosion. This could be done visually by flying drones. Another interesting option for SHE is using acoustic sensors in order to assess unforeseen changes in pitch and sound power level (SPL) caused by possible faults along the blades.

OCT: The operations control systems would be used during maintenance itself. As such, inspection during the maintenance visits should suffice. Other than that, any electronic systems could be easily monitored remotely.

A key takeaway from the list above is that key to improving maintenance and operations, the system has to be closely monitored. Due to the sheer size of the system, autonomous monitoring by means of drones is a necessity. Many other sensors more specific to each subsystem would be needed as well in order to implement the preventative maintenance strategy. Overall, while meaning a higher initial cost, this would result in reduced operational and maintenance costs for the system offshore.

4.3. Logistics strategy

The financial success of an offshore wind farm depends to a high degree on the transport and installation phases, the use of appropriate logistics procedures. Transport and installation processes differ significantly depending on the type of design considered and the location of the farm site. Logistics and supply chain management of maintenance is a very critical task in the offshore wind energy industry. In this section, multiple aspects of the logistics of this project are presented and discussed.

4.3.1. Storing and repairing parts

In order to have an efficient and safe maintenance service, personnel performing maintenance to the wind turbines needs to have easy access to spare parts. If possible, spare parts are often stored in specific warehouses close to the wind turbine site, known as depots [38]. For the design presented in this paper, only one depot will be considered due to the potentially limited extent of the wind farm and the limitations in the project's cost. Inside this facility, both repairable and discardable parts may be stored, and the quantity of each item is normally known as the stock level of the storage [38]. Warehouses make up the entire skeleton of the support aspect of the project and can also allow for repairs of certain components. Apart from (minor) repairs done at the depot, most broken items are sent to a workshop for repair. Most of the time, workshops are in small designated areas close to the depot, where each turbine component's repair facilities are provided. Especially for advanced equipment, the workshop can often be the property of the part manufacturer. In some cases, operators get a new item from the manufacturer in exchange for sending a broken item obtaining a deduction on the component's price. The time it takes for an item to be repaired and returned to the depot is called turn-around time (TAT). This is a very important parameter when optimising stocks for repairable items [38]. Finally, every item needs to be properly collected inside the depot and an inventory of all the elements needs to be performed. This is done to keep track of and identify all the stored items.

4.3.2. Transportation

Transportation is one of the biggest challenges in designing and building a wind farm. The large size and weight of most of the components make the design extremely hard to transport, even for small distances. Due to the increase in the number of components, the amount of transfers for novel turbines are higher than for conventional HAWTs, increasing even more the cost of the project's logistics [39]. For the design considered in this paper, a proper transportation strategy will need to be defined to deliver the necessary equipment safely and to minimise costs. It would be favourable to have the manufacturer factory close enough to the site to avoid long travels of the components by ship and to reduce the costs. Once all the components are close enough to the construction site, vessels and helicopters will need to be hired to transport them to the desired location. A logistics team will determine the most efficient routes, schedule vessel availability, and ensure that the components arrive at the right time to avoid construction delays. For the offshore case, crew transportation also needs to be considered since a proper network must be designed to ensure that operators reach the wind farm site and perform their job. A strategy must also be developed for the maintenance equipment and spare parts transportation. This aspect is critical, especially in case of a sudden change in weather conditions. Any failure to deliver proper maintenance support for operators must, in fact, be taken into account and safely tackled. Thus the reliability of the chosen transport method is a very important factor as well [40].

4.3.3. Site accessibility

Although they look pretty much similar, at least in shape, onshore and offshore wind turbines present important differences that must be addressed. Besides size and cost, the biggest difference between onshore and offshore wind farms is the accessibility of the site on which the farm is built. While onshore turbines are located in relatively accessible places, in isolated areas close to the main infrastructures, offshore farms are located in very remote places in the sea, far from any civilisation. This represents a big challenge for the design of the project's logistics, characterized by the fact that both the installation and maintenance are more difficult to achieve. As a consequence, to design an efficient offshore wind turbine, it is necessary to take into account all the issues related to the accessibility of the farm. The complete wind farm may be inaccessible by boat or helicopter for a period going from days to months due to harsh weather conditions (wind and waves) [40]. This is a random and unpredictable event that may lead to criticalities and delays in the operations of the wind turbine. The only way to mitigate this issue is by automating the maintenance procedure as much as possible, such as reducing the number of man-made maintenance. On the other hand, even when weather permits access to the turbines, offshore maintenance costs far higher than the equivalent on shore due to the transportation of the personnel and the necessary equipment. This topic be discussed in a separate subsection. Another accessibility issue is related to the lifting actions performed during the system's installation. The team will need to take into account different methods to transport and assemble all the farm components to the farm site to start operations. Although commercial wind turbines are very reliable nowadays, both limited access and limited availability of maintenance equipment may easily lead to an unacceptable downtime level. This makes it inevitable to assess the O&M demand of an offshore wind farm in conjunction with the other design parameters[40].

5

Verification and Validation

In this chapter, the models used for calculating the monopile and floater dimensions and characteristics are verified in Section 5.1, Section 5.2 and validated in Section 5.3, Section 5.4.

5.1. Verification for monopile

In order to verify the algorithm used for designing the turbine's foundation, the sensitivity analysis method was chosen. This method relies on tweaking a few parameters to check whether the outputs and other function variables behave according to expectations or not. The input numbers that will experience changes are the forces that were taken as granted from the tower analysis, namely, the moments, lateral forces from the airfoil and wind and the compression force generated by the structure above the pile. They will be progressively increased by 10 %, 25 % and finally 50 %.

The sensitivity analysis aimed to examine the bending stress and thickness. The reason for choosing these two parameters is that bending failure is the most probable way of failure for the foundation. Euler buckling or failure in torsion are also possible scenarios but less likely. The stress reaches its maximal value at the base of the pile since the arm of the forces is the largest there. As the thickness is one of the inputs, it should be change to achieve the desired resistance against failure. The lines follow a logarithmic trend as depicted in fig. 5.1. The more the forces and moments are increased, the thicker the monopile needs to be. The reference value for the outer diameter was not tweaked. It was previously set to 9 m. To ensure the foundation is stiff enough, the experienced bending stress at the base should be lower than the Yield stress, for which a safety factor of 1.5 was applied. This is translated into having a value for the bending stress underneath the magenta horizontal line. For instance, when the input forces and moments are $F_{wind} = 2001kN$, $F_{airfoil} = 5699kN$, $M_{airfoil} = -13710kNm$ and $F_{compression} = 44619kN$, the thickness of the pile shall be minimum around 0.185 m. When the forces are increased by 10 %, 25 % and 50 %, the minimal thicknesses are roughly 0.205 m, 0.23 m and 0.27 m, respectively.

The second option in the sensitivity analysis was to investigate the bending stress together with the outer diameter of the structure. Once again, the diameter is an input variable and a design option. It dictates the foundation's final geometry. Moreover, the most critical stress is the bending one, which reaches its ultimate value at the bottom point of the cylinder. Below, it will presented how the bending stress varies with respect to the outer diameter:

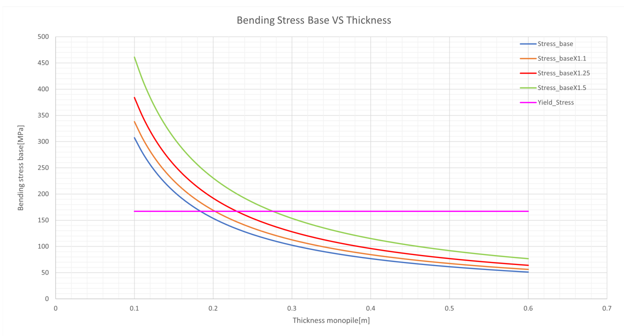


Figure 5.1: *Bending stress at the bottom point of the monopile expressed as function of its thickness*

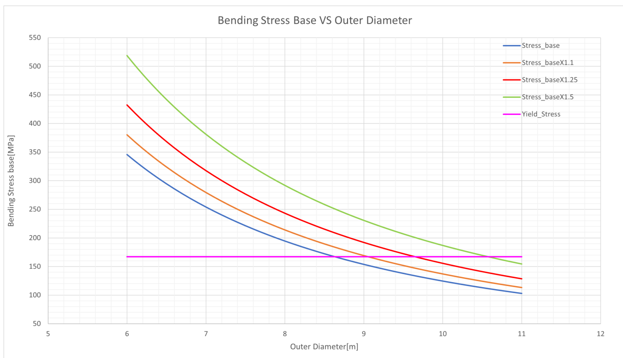


Figure 5.2: *Bending stress at the bottom point of the monopile expressed as function of its outer diameter*

In fig. 5.2 the magenta line showcases the Yield stress of steel. The displayed value of 167 MPa is lower than the actual one since a safety factor of 1.5 was applied. For this case of the study, only the moments and forces were tweaked. The number assumed for the thickness of the cylinder is 0.2 m. From the graph it can be observed that all lines, except for the horizontal one, have a logarithmic shape. In accordance with expectations, once the forces are increased, the diameter needs to be larger to make the structure stiff enough to not fail in bending. In particular, for the mentioned values of $F_{wind} = 2001 kN$, $F_{airfoil} = 5699 kN$, $M_{airfoil} = -13713 kNm$ and $F_{compression} = 44619 kN$, the minimal diameter of the body should be around 8.65 m, while when they are boosted by 10 %, 25 % and 50 %, the marginal number for the diameter should be approximately 9.1 m, 9.65 m and 10.65 m, respectively.

5.2. Verification of floater model

The floater model used in Chapter 3, was made using a scaling method proposed by Wu and Kim, as described in Subsection 2.4.3. The paper includes figures on two floaters scaled by Wu and Kim, one for a 10 MW turbine and another for a 15 MW turbine. To verify that their method was implemented correctly for the 60 MW turbine floater in this report, calculations were made for 10 MW and 15 MW turbine floaters as well, that can be compared to the reference figures from Wu and Kim. Alongside reference figures for the floater, reference figures for 10 MW and 15 MW turbine estimates are provided as well, the masses of which were used as a starting point for the semi-submersible estimates. To compare, the same submersible scaling parameter s_s was used for the calculated figures, as used in the paper. The results for the 10 MW and 15 MW turbines can be seen in Table 5.1 and Table 5.2 respectively.

While it may be expected that these figures match exactly, there are a few sources of error to take into account. First of all, the paper does not provide information on a few pieces of information, such as the way the ballast mass is distributed and the reasoning for distributing in that manner. For the calculated figures, the assumption was made that the lower columns were filled with ballast water entirely before the upper columns. The overturning moment considered for the static pitch angle is also not provided. For the calculated figures, the overturning moment for a 5 MW floater was calculated from mass, GM, and static pitch angle figures provided by [1]. This moment could then be upscaled by $s_t^{2.3}$[1]. Another source of error is the figures taken from the paper to perform calculations, only being provided in a set number of significant figures, while calculations by Wu and Kim are only rounded at the end. This can already be seen for the column distance and radius in Table 5.1, showing their s_s not to be exact, but a rounded figure. The same is true for turbine masses and z_{CG} figures used as a calculation starting point.

While the figures in Table 5.1, and Table 5.2 do not match exactly, the errors are small at less than 5 %, which is deemed an acceptable margin for this stage of design. In addition, a comparison between Table 5.1, and Table 5.2 shows that the errors are not rapidly diverging, which is important as the model is extrapolated further to 60 MW.

Table 5.1: *Comparison table between calculated parameters for a 10 MW floater using the floater model from Wu and Kim, and reference figures from the source paper [1]*

	Calculated 10 MW	Reference 10 MW [1]	Relative difference %
s_s	1.24	1.24	0.00
Outer column distance [m]	62	62.05	-0.08
Outer upper column radius [m]	7.44	7.45	-0.13
Metal mass [t]	5255	5250	0.10
Ballast mass [t]	15321	15070	1.67
Total platform mass [t]	20576	20320	1.26
GM [m]	10.75	10.37	3.66
Static pitch angle [deg]	6.03	6.26	-3.67

Table 5.2: *Comparison table between calculated parameters for a 15 MW floater using the floater model from Wu and Kim, and reference figures from the source paper [1].*

	Calculated 15 MW	Reference 15 MW [1]	Relative difference %
s_s	1.42	1.42	0.00
Outer column distance [m]	71	71	0.00
Outer upper column radius [m]	8.52	8.52	0.00
Metal mass [t]	6393	6370	0.36
Ballast mass [t]	20159	19870	1.45
Total platform mass [t]	26552	26240	1.19
GM [m]	13.2	12.75	3.53
Static pitch angle [deg]	6.16	6.21	-0.81

5.3. Validation of monopile model

Empirical relations have been found in literature that estimate the correlations between the length, outer diameter, and total weight. Equation 5.1 [15] is presented below where L in m is the total length and D is the diameter expressed in m. Equation 5.2 [15] relates the total length and weight W in tonnes of the monopile.

$$L_t = 14 \cdot D - 17 \tag{5.1}$$

$$W = 16.5 \cdot L_t - 392 \tag{5.2}$$

The models that predict the mass of the monopile starting from the total length will be compared. The reference model is introduced in eq. (5.1). Below, two figures will be presented with the differences between the two ways of estimation. Figure 5.3 showcases the graph for which the thickness of the cylinder was assumed to be 0.2 m, which corresponds to the lowest value for ensuring the pile does not fail in bending. In contrast, fig. 5.4 showcases the scenario when the wall-thickness is 0.5 m. This wall thickness is considered realistic, as the outer diameter was assumed to be 9 m, leading to a thickness-to-diameter ratio of roughly 5.5 %, and the minimum thickness was 0.2 m. In order to assess the possibility of failure, $\sigma_{yield} = \sigma_{bending}$. A safety factor of 1.5 was applied to the σ_{yield}.

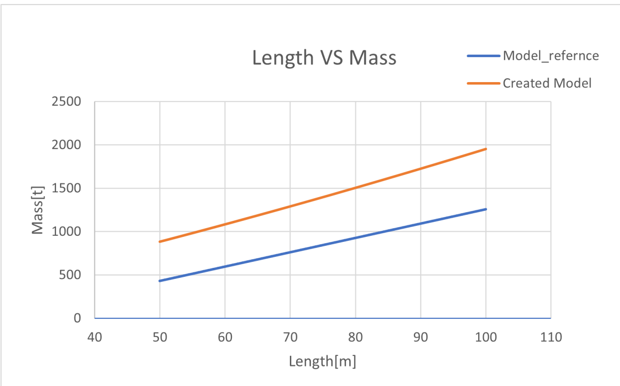


Figure 5.3: *Total length expressed as a function of the mass- $t = 0.2m$*

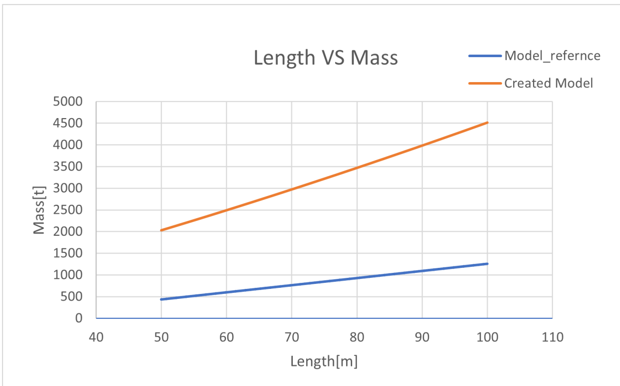


Figure 5.4: *Total length expressed as a function of the mass- $t = 0.5m$*

As seen in fig. 5.3 and fig. 5.4, the estimation of the two models do not match.The difference between the masses is about 500 t when the length is 50 m, but the more it increases, the more the length enlarges. Both lines have a constant slope, but one of the created models has a higher mass. This can be observed especially in the right figure. When the thickness is increased, the correlation between the two methods is even weaker. The difference between masses is roughly 1500 t at the beginning, and increases to around 3250 t. It cannot be concluded that the created model failed since the reference model is also based on empirical data. The discrepancies may come from the fact the structure of the designed wind turbines is massive. Moreover, the implications of the assumptions made need to be reviewed. First of all, a few forces have been simplified or even neglected, such as the wave load, and aerodynamic load on the pile structure. Secondly, the conducted analysis was made based on a simplistic structure where only a few design features have been considered, for instance, the variation of the thickness or diameter of the pile along its length or potential small existent floaters. On the other hand, the estimated numbers have the same order of magnitude, indicating that the initial estimations are sufficiently accurate.

The models predicting the total mass of the pile based on the outer diameter will be presented next. Once more, it was considered that the critical stress experienced is the bending one at the base of the monopile. The reference model for the following comparison was introduced in eq. (5.2). The forces and moments from the tower structure were assumed to be inputs. Two separate cases will be explained. The first one implies that the driving length of the monopile can be counted in the total length, and the second one does not. Nevertheless, considering that the load exerted on the structure, which is massive compared to normal offshore wind turbines, is enormous, a large driving length might be required. The approximation based on empirical data outputs a driving length of 67 m. Two scenarios were examined where the thickness of was varied from 0.2 m to 0.5 m. The figures are presented below:

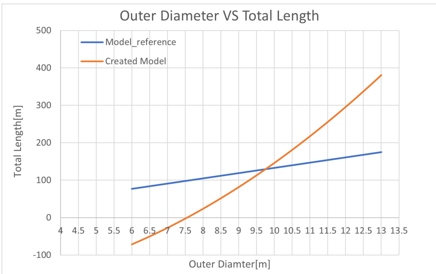


Figure 5.5: *Total length expressed as a function of the outer diameter-pile length not included-* $t = 0.2m$

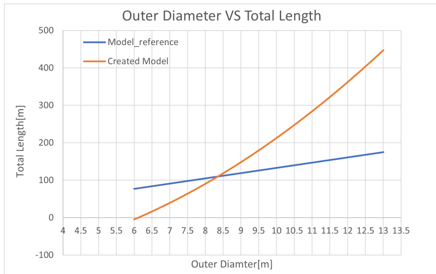


Figure 5.6: *Total length expressed as a function of the outer diameter-pile length included-* $t = 0.2m$

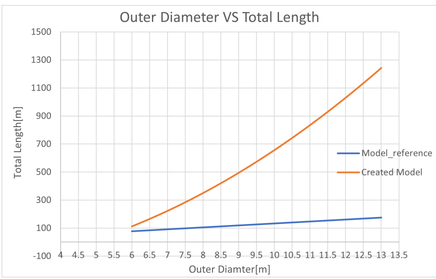


Figure 5.7: *Total length expressed as a function of the outer diameter-pile length not included-* $t = 0.5m$

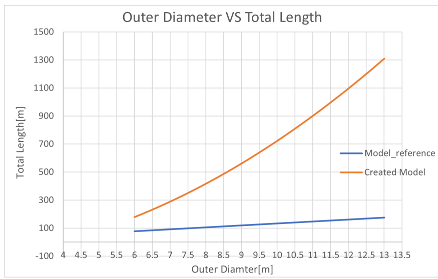


Figure 5.8: *Total length expressed as a function of the outer diameter-pile length included-* $t = 0.5m$

fig. 5.5 and fig. 5.6 have a sufficient match for a range of values.

The graphs from the left side display the situation when the driving length is not included in the total length. For this possibility, the outputs of both models are sufficiently close when the diameter is between 9.2 m and 10.2 m. By contrast, when the driving length is included, the models have similar values for a range of values of 8 m to 9 m. According to Kallehave et al., monopiles with diameters up to 10 m are a viable option for waters in water depths up to 60 m.

Figure 5.7 and fig. 5.8 compare the models when the thickness of the pile is 0.5 m. The pairing between the two methods will be present for a diameter less than 6 m for both cases, driving length included or not. This is not feasible for the designed case. Nevertheless, the two techniques' correlation is better for the left graph, while for the right one there is no visible match. T

To conclude, the empirical relation from which the reference model was constructed is not perfectly accurate for the conducted analysis. The difference comes from the designed wind turbine's unique structure and colossal size. Furthermore, the numbers differ since this is the first estimation of the entire turbine body where multiple assumptions have been considered. Furthermore, simplified examples have been used. The numbers do not differ more than an order of magnitude especially for the outer diameter and total length comparison, which validates that the method was good enough for the start approximation.

5.4. Validation of floater model

The floater estimation model used in this report was proposed by Wu and Kim, who compare their upscaled estimates to a reference 15 MW in their paper, which seems to be in reasonable agreement [1]. While Wu and Kim propose that their model can be used to upscale semi-submersible floaters beyond 15 MW, a floater for a 60 MW turbine is a significant extrapolation. A few concerns arise, such as the fact that the radii of connecting members are kept constant, as well as the wall thicknesses of all members. To extrapolate to a 60 MW turbine floater from 5 MW, the triangle side length was almost doubled, without further reinforcing the connecting members, which could lead to structural integrity problems. If a floating turbine is developed in later design stages, these issues should be addressed. However, for this stage of design, and for the sake of the trade-off in Chapter 3, this model is considered valid enough.

Below in Figure 5.9, the mass of the 60 MW floater is compared to the reference figures for 5 MW to 15 MW floaters. This figure shows that the platform mass for the 60 MW floater relative to its power is clearly smaller than for the other figures. This can be explained by the fact that the overturning moment is much lower for the 60 MW turbine design than the overturning moment scaled using the same method as for the reference figure, at 1.58 GNm compared to a scaled 14.1 GNm. Due to this lower overturning moment, the platform can be significantly smaller. The lower overturning moment can be partially explained by the fact that the 60 MW-MRS, is wider than it is tall, lowering the center of thrust compared to a hypothetical traditional wind turbine design of the same power output.

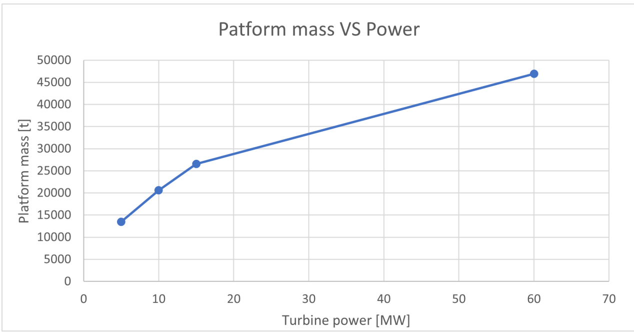


Figure 5.9: *A platform mass vs turbine power comparison between the calculated* 60 MW *figure, and reference figures for 5, 10, and* 15 MW *designs*

6
Conceptual Design

This chapter describes various characteristics of the design option chosen in Chapter 3. Section 6.1 describes the tower structure, then Section 6.2 explains some considerations made during material selection after which the aerodynamic characteristics of the system are described in Section 6.3. Section 6.4 details the control system, Section 6.5 explains power storage and control methods, and finally Section 6.6 describes the yaw control system.

6.1. Structural characteristics

The system's structural configuration is the result of the trade-off performed in Section 3.5 and the design discussed in Subsection 2.4.5. The structure of the system starts with the monopile, which connects it to the ocean floor. On top of the monopile, which extends 30 m, there is a large bearing, which allows the rest of the system to yaw on top of it. On top of this bearing, the system's tower is mounted. The tower is a rectangular structure with a height of and the 280 m and a width of 530 m. The most efficient depth of the structure in terms of weight, according to Jamieson et al., is 12 % of the overall structural weight, which for this design would result in a bit under 65 m.

The tower structure is to be made of trusses. The large outer truss frame is subdivided into smaller rectangular cells, which house individual shafts. The walls of the cells are reinforced with more trusses, except for the wind-facing front side. That side is left open so that wind can reach the turbine unobstructed. The wind turbines will have a vertical axis and the system's rotors will be grouped column-wise with common shafts.

The part of the tower between the extreme wave height and the beginning of the bottom turbine is the structure's base plate. It is a flat platform on which all the generators and the yaw system are mounted on. It is also where the on-site support equipment may be stored. There also may be enough space to install other maintenance-supporting equipment, such as elevators, weather shelters, and emergency accommodations.

To facilitate maintenance better, the base plate and tower structure have to feature plenty of support equipment. The base plate shall be equipped with protective railing and splash guards to shield personnel and equipment from harsh wind and marine conditions. Some of the larger trusses of the tower structure would also be converted into walkways with proper rail guards and stair/elevator access. This would greatly improve the maintainability of the system and reduce operating costs. The large vertical truss supports between the individual rotor cells would likely make them prime locations for mounting elevators or smaller cargo lifts, allowing for physically smaller parts to be maintained with almost no additional supporting equipment.

In order to facilitate maintenance, several sensors would have to be installed in the structure [1]. This would include both sensors using electromagnetic effects and ultrasound to monitor surface cracks' development. This would allow for the usage of predictive maintenance, which would reduce the overall operational costs. Due to relatively low costs, some cameras and drone support equipment should also be installed to allow for quick and simple visual inspection.

The loads on the structure are described in Subsection 2.4.2. The tower experiences aerodynamic loading, the magnitude of which is estimated to be 2.0 MN. The HLD airfoil produces a drag force of 5.7 MN, a lift force (downwards) of 44.6 MN, and a bending moment of 13.7 MN. The only other load considered

[1] URL: https://www.nde-ed.org/NDETechniques/index.xhtml [cited: 24 May 2023]

now is the wave loading, which was assumed to be uniform over the entire length of the monopile, with a magnitude of $330\,\mathrm{kN\,m^{-1}}$. Loading is presented in Table 2.4

6.2. Material characteristics

The design's choice of material has various subdivisions, the largest being the choice for the underwater structure material, the above-sea structure, and the material of the rotors themselves. However, the choice also must include and be made with the maintenance strategies in mind.

The underwater structure needs to have the material characteristics to withstand the loading of the rest of the turbine design, including the stiffness to minimise bending and sway of the turbine system, as well as the harsh environmental conditions of being submerged in potentially high salinity salt water. This is in addition to how any failures in the system will be challenging to fix, given the structure is load-bearing for the rest of the design.

The material selection for the structure above the water has to deal with a more complex loading than that underwater since they are in direct contact with the RNA but it is also working with smaller moments by comparison. In addition to this, the environment it is working in is predominantly dry and exposed to sea air as opposed to seawater leading to partially dry working conditions.

For the structural components discussed, the materials used must satisfy cost, sustainability, and lifespan requirements to align with the rest of the structure. Specifically, this limits the cost, durability, and maintenance design space for the materials. In addition to this, given that the sustainability of the structure is also a goal, the manufacturing, maintenance, and end-of-life procedures are also under scrutiny.

An overview of current structures has shown that offshore structures have been using alloyed steel and concrete as the main materials in the foundation and support structures [28]. Given the above-sea structure is to be made of trusses, the optimal material choice will be an alloy of steel, keeping in line with current offshore construction trends. The exact alloy of steel will be subject to a trade-off in the subsystem design stage of the project.

A similar trend for the underwater structure is seen in existing structures [28], leading to, once again, the choice of steel alloy for the material. This, again will be made into a more detailed trade-off to find the best alloy for the job. The difference in environmental conditions as well as loading may lead to separate alloys being selected for above and underwater structures

In addition to this choice, due to the corrosive nature of the environment, a further trade-off on corrosion resistance methods will need to be done to compare active and passive corrosion protection methods, in order to discuss maintenance functions in more depth. The choice of materials and the final design will also have to be in line with the relevant standards for construction. Of particular importance is ISO 19902:2020 on fixed steel offshore structures from the offshore Oil and gas industry. Given that there is more documentation on the standards for the oil and gas industry which involve the creation of similar platforms, these will be used in place of renewable energy standards when they cannot be found.

Finally, the rotors carry no loads except for the aerodynamic loads and are the source of the loading on the structure. In addition to this, they are placed higher up on the structure leading to predominantly dry working conditions. They are also the easiest structural components to replace and are under the largest changing fatigue conditions as a result of the loading. This leads to a different set of conditions for material choice that will lead to different material trade-offs. Current offshore data [28] describes the usage of composites, polymers, and glass and carbon fibers in their design which have the relevant fatigue and material characteristics. However, these materials are very energy intensive to create and are also complicated to recycle at the end of life [42] [43], especially at competitive costs when compared to more traditional materials, mainly steel and metal alloys. This means that another trade-off will be done between steel and composite material to gauge the subsystem's optimal material.

6.3. Aerodynamic characteristics

It is crucial for the success of the design to have a good understanding of the aerodynamic of the wind turbine. In this section the characteristics of the airfoil, the way the angle of attack changes throughout the rotation and the behavior of the wake will be discussed.

6.3.1. Airfoil characteristics

For the preliminary design starting point, airfoil characteristics of the [8] are carried. DU17DBD25 airfoil is used by [8], which has power and thrust coefficients $C_{p,max} = 0.47$ & $C_{t,max} = 0.5$ which are obtained for TSR $\lambda = 4.5$. Optimisation research for airfoil shape has been done by [44] for pitch-controlled airfoils. The optimization of an airfoil is out of scope for this stage of the design and most likely out of scope for detailed design as well; therefore topology of the airfoil will not be changed or outsourced.

6.3.2. Stall Characteristics

For the preliminary design, blades with pitch control are assumed, although they introduce structural complexity; otherwise, the stall is expected in the regions close to the azimuth angles $\theta = \pi/2$ and $\theta = \pi$, and the width of this region is independent of the free stream velocity and is the only function of azimuth angle and TSR. Therefore passive stalling may not be achievable for the proposed design. With the dynamic stall characteristics, it is expected to limit the rotational speed under extreme conditions described under the requirements, therefore preventing structural damage. The simple calculation for the stall region is below 6.1.

$$\left.\begin{aligned} v_r &= \lambda \cdot v_{inf} \\ v_n^2 &= v_{\text{inf}}^2 + v_r^2 - 2 v_{\text{inf}} \cdot v_r \cdot \cos(\pi - \theta) \\ v_{inf}^2 &= v_n^2 + v_r^2 - 2 \cdot v_n \cdot v_{inf} \cdot \cos(\alpha) \end{aligned}\right\} \Rightarrow \alpha = \arccos\left(\frac{\cos(\theta) + \lambda}{\sqrt{1 + 2\lambda\cos(\theta) + \lambda^2}}\right) \tag{6.1}$$

This results in 6.2 for AoA (α) for azimuth angle (θ). The orange line below is the stall range for DU17DBD25 [45]. Parts of the α above the stall angle correspond to the stall region, which is 23.25% of the whole rotation; therefore, a pitching system with a pitch cycle is beneficial to increase efficiency and reduce vibrations due to separation.

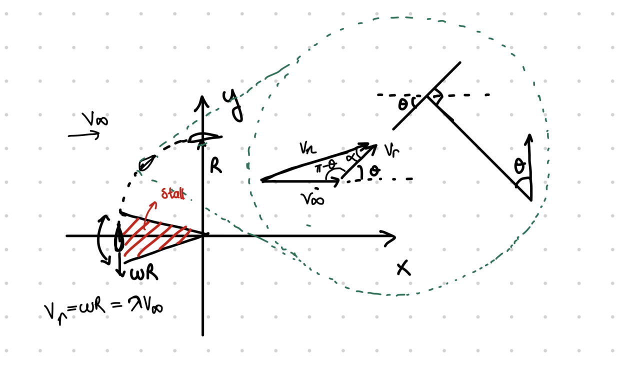


Figure 6.1: *XY plane view*

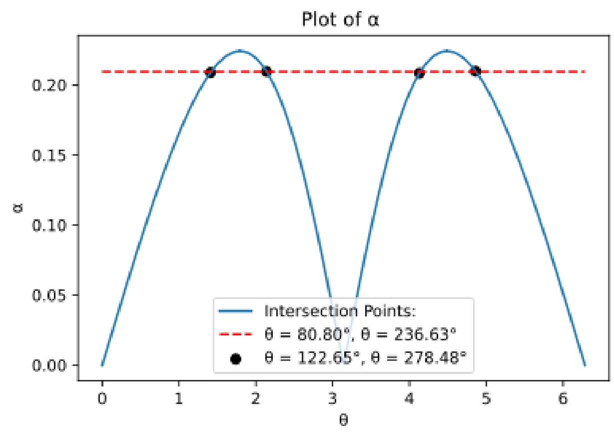


Figure 6.2: *α-plot*

6.3.3. Wake Recovery

In order to meet power density requirements and go beyond them, a wake recovery system using a high-lift device placed on the structure is proposed. However, the analysis of the wake regime is not done, considering this is the preliminary design for a single system, not the wind farm. The planned design at this stage is having a high lift device placed on top of the structure to push the wake regime upwards and re-energize it; in the detailed design stage, other installation points (sides of the structure) for HLD will also be considered. A wake model has been proposed, but the simulation of the model is not working as expected for now. In the detailed design stage efficiency of this system will be investigated by either a vortex line method provided by Ferreira or an actuator cylinder method based on Madsen's theory [47].

6.3.4. Turbine Type

A turbine with H blades is proposed because it has the highest space-filling ratio of the rotational volume to total volume. However, the optimum solidity of DU17DBD25 is not studied in [45]; therefore, 0.075 is assumed. 3 or 2 Blade design is proposed for the uniformity of the loading since both a lower number of rotors per shaft is considered for proposed design (1 and 2) and higher (6) than Jamieson et al. in which 4 is used. In the detailed design, optimum solidity will be inspected, as well as the effect of having 3 blades instead of 2 on the material cost and structural loading. Also, for preliminary design aspect ratio of ≥ five is considered; therefore, change in C_p due to AR will not be considered since it only affects performance ≤ 0.5% [8].

6.4. Pitch control

The ideal operational envelope of a wind turbine is presented in fig. 6.3, divided into three main phases. Depending on the wind speed, the control system must oversee and dictate the optimum operation throughout all operational phases. Thus, it is important to understand the limiting factors that describe these 3 phases.

Before V_{cut-in}, the cost of starting up and operating the wind turbine overshadows the possible revenue collected within this very low wind speed area. Thus, the control system must be able to be informed by the operation control system about the real-time wind conditions and decide if the wind turbine shall be powered up. For this purpose, the control system shall include a mechanical brake that can prevent the turbine from rotating when operating conditions are not met. This brake could also be used to help in parking the turbine when wind speeds exceed the cut-out speed, $V_{cut-out}$.

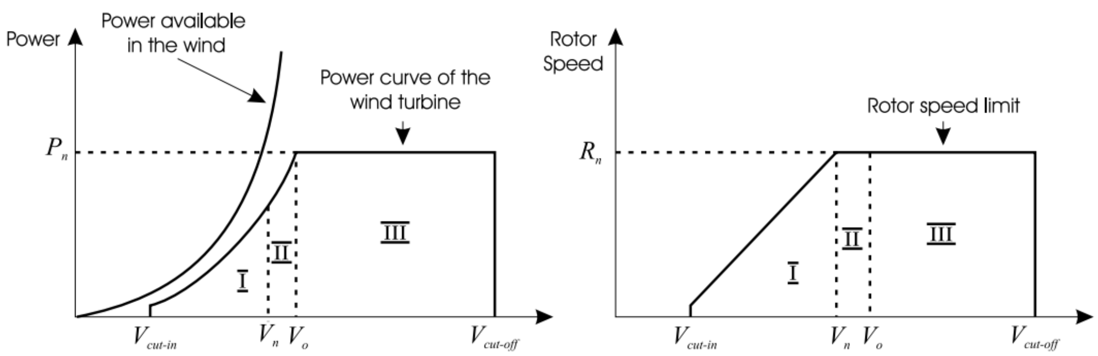


Figure 6.3: *Ideal operational envelope, considering both power and rotor speed [48]*

The first phase is defined between the cut-in speed of the system, V_{cut-in}, and the rated rotor speed V_n. Within this phase, it is important that the most wind energy can be collected and, in turn, converted into electrical energy. The conceptual design of this system has been largely based on a set of assumptions, one of the most important being that the rotor operates at a constant tip-speed ratio. This assumption was made so that the power coefficient could be equated to the optimal value set by Jamieson et al., namely 0.47. Yet, in order to maintain a constant and optimum power coefficient and inadvertently a constant tip speed ratio, an additional control system needs to be included. The most conventional solution to this problem is incorporating a pitching system for the blades so that the aerodynamic force on the airfoil can be controlled, but this increases the system's complexity, decreases overall reliability and increases the maintenance costs.

Given that design simplicity and ease of maintenance are design drivers for the current system, it may seem that pitch control does not present itself as a viable solution. But, having a fixed pitch rotor would mean that the optimum electricity production is only met at a certain windspeed when the optimum tip speed ratio is achieved. Thus, by choosing a non-variable pitch system the annual energy production and the annual revenue would decrease. This would cause the LCOE and the energy density of the system to decrease as well, lowering the chances of the system meeting the user requirements. Thus, it is necessary to compromise and consider a pitch system for the vertical rotors.

The added complexity and maintenance effort to the design by the pitch control system may be alleviated by other design considerations. Considering that each vertical shaft would connect to multiple rotors, it is certain that bearings are going to be used between two separate rotors. According to Carroll et al. the generator bearing accounts for 11% of all generators failures. Considering that a rotor bearing would carry a similar amount of torque, it is reasonable to say that maintenance access must be considered for the bearings, even more so when the number of shafts is taken into account. Thus, it is possible to integrate a pitching system at the base of each rotor, close enough to the bearings, so that maintenance can be done on both simultaneously.

The second phase is similar in shape to the first phase of the power curve, except that it spans windspeeds between the rotor-rated speed and the windspeed that yields the rated power. Given limit load considerations, the speed of the rotor needs to be limited so structural failure is avoided. In order to do so, an active stall of the blade airfoil can be used. Through this approach, the blade can be strategically pitched in order to force the blade into stalling, thus maintaining the torque and RPM of the rotor to acceptable values. Yet, this would require the pitching system to withstand increasingly high static and dynamic loads due to the constant pitching of the blade. Moreover, having a long blade would lead to a variable distribution of aerodynamic loads across the vertical axis, which could create unwanted twists. This is why another interesting approach for the power control subsystem is the addition of high-lift devices that do not span the entire blade length. Further considerations of this subsystem will be evaluated in the detailed design phase. The third phase, which spans from the power-rated wind speed until the cut-out speed, can employ a similar control strategy.

Choosing a pitching system would also improve the performance of the system while encountering gusts. Given that the drive train configuration includes a DFIG, it is possible to use generator torque control paired with the pitching system. When the operational control system encounters gusts, the slip and the controlling frequency of the DFIG can be modified so that the time constant of the pitch control is increased, further decreasing the complexity of the pitching system [49].

6.5. Power storage and control

Due to the stochastic nature of wind, the electric power generated by wind turbines gets highly random over time, having crucial consequences both on the power quality and the planning of power received by the subsystems. As a consequence, Energy Storage Systems play an important role in wind energy applications by controlling the power plant output and providing auxiliary services to the power system. Multiple energy storage systems exist in the market specifically for wind turbine applications and their power control. Each of them presents different advantages and disadvantages that may lead to the design of certain options instead of others based on the system's requirements. For this paper, multiple design options are considered and analysed to perform a trade-off between them in the final report. This is done since design parameters, such as the power demand requirement of the entire system and its response time, still need to be defined. The options explored are the following:

Superconducting Magnetic Energy Storage (SMES) It consists of a superconductor coil, a power-improving system, and a cooling system. The main advantages of this system are a long life span, high efficiency

(>95%), high power density, and fast discharging ability. On the other hand, the disadvantages are the extra energy consumed by the cooling system, the high cost of the superconductor, the low energy density and the design complexity of converters.

Super-capacitor Energy Storage System: They are specific types of electrochemical capacitors where no chemical reactions are involved in storing energy. They have a higher storage capacity than typical capacitors due to the two metal plates being coated with porous materials. The main advantages of this system are its high efficiency, extremely low internal resistance, long life span, and no overcharging stress. On the other hand, the disadvantages are low energy density, cost per unit energy capacity, and the high rate of self-discharge characteristic that limits application in long-term energy storage.

Compressed Air Energy Storage (CAES): The Compressed Air Energy Storage system consists of several components, including a motor, a compressor, an underground capsule for storing compressed air, system control equipment, and a combustion chamber. The capacity of CAES systems ranges from 50 to 300 MW, being higher than all the other storage methods considered. The main advantages of using the CAES are the very high power and energy capacity and the long lifespan. On the contrary, the main disadvantage of this system is requiring extra energy to provide heat during the expansion cycle, leading to an adverse environmental impact.

Flywheel Energy Storage (FES): A flywheel stores the electrical energy as kinetic energy in a rotating object. The main components of a flywheel system are a motor/generator, flywheel, bearings, power electronic devices, and a vacuum chamber to minimise friction and power losses. This system absorbs electrical energy from the grid in off-peak hours and rotates the flywheel using an electrical motor to store its kinetic energy. The main FES advantages are low maintenance requirements, fast charge capabilities, high power density, and fast response times. On the other hand, its main disadvantages are low energy density compared with battery systems, the requirement of precisely designed components, and the high cost of it.

Batteries: Batteries have always been used to store electrical energy through chemical reactions. They are commonly used for long-term energy storage, despite being relatively expensive and having a limited lifespan. Different types of batteries exist in the market and differ by the materials used. The main components of batteries are negative and positive electrodes, which are separated by an isolator. The feature of the low discharge rate makes batteries more suitable for long-time charging. Nowadays, research focused on the material improvement of these batteries has led to advancements in deep discharging ability making them suitable for wind energy generation systems.

6.6. Yaw control

Yaw control is an essential subsystem; its function is to rotate the system around its Z-axis to match desired performance. This is mainly done by orienting the structure in the most favourable attitude to maximise efficiency. For the design considered, an active yawing system is implemented. This is due to the criticality of yawing in the overall design. Due to the size and requirements regarding the power density and power produced of the desired offshore wind turbine, having a passive yaw system would not have been ideal for achieving the desired performance. After performing a trade-off, considering all the most feasible active yaw control design options, a combination of two resulted. The main yawing system uses aerodynamic yaw. This option depends on the reliability of almost all the turbines and works thanks to their differential rotation. Consequently, a proper controller must be designed to provide the correct input to the individual rotors to attain the desired performance. This will be done in the next report once more information about the performance of the final design is defined. The fact that the aerodynamic control system requires the turbines to be always functioning may be limiting, especially for multi-rotor turbines. When a rotor failure may not yet warrant maintenance, the effectiveness of the yaw system would fall. For this reason, an electric yawing control system is also considered a backup option. The main benefit of this configuration is related to the complementarity of the two systems. Both of them will be connected to the same yaw bearing, thus reducing the complexity. In addition, due to the fragility of the aerodynamic system, having a backup option would be very useful in case maintenance for it takes more time than expected.

7
Technical Risk Assessment

In this chapter, the technical risk assessment of the project mission is performed. This consists of identifying the technical risks that affect the success of the project mission. The risks are quantified according to their perceived probability of occurrence and seriousness of impact. Next, a mitigation plan is devised for the risks that pose the highest impact on the project mission to bring them down to an acceptable level, including contingency for the risks that remain at a high level.

7.1. Risk identification

Risk categorisation

To identify the technical risks affecting the designed system, risk categories were first identified to break down the aspects of the project where risks might arise. This is broken down into:

Technical performance risks These affect the system during operation, causing it to perform to a lower performance level than required. These risks can be broken down for each subsystem at this design stage.

Cost risks These are risks which can increase the project's costs beyond the allocated cost budget.

Scheduling risks These are risks which can cause a delay in the scheduling of the project mission. This includes the system's design, production, transportation, operation and decommissioning.

Sustainability risks Since sustainability is a driving factor in the design of this mission, risks related to not meeting the sustainability goals of the system or inadvertently becoming unsustainable are included in this category

Programmatic risks These are risks which result from events out of the control of the project management. This can include events arising from higher management or international or national directives. This can also include natural disasters and other events that pose a risk to the mission's success.

The likelihood of the risks is categorised into: very unlikely with a chance of occurrence less than five percent (<5%), unlikely (<25%), plausible (<50%), likely (<95%) and very likely (>95%). Furthermore, the consequences were divided into negligible, marginal, critical and catastrophic implications for the project. Negligible risks incur no reductions in technical performance; marginal risks incur a slight reduction in technical performance; critical risks reduce technical performance significantly to a point where system success is questionable; catastrophic risks cause some of the mission requirements not to be achieved, leading to mission failure [1].

A few subsystem risks were added from literature. Hou et al. discuss several risks that govern the monopile subsystem. During installation, these include pile sliding due to soil properties, hammer refusal if the monopile is allowed to set while installing, and damage due to crane accidents. The operational risks include scouring and corrosion due to the sea environment, fatigue failure and collisions with ships [50]. For the generators and gearbox, Shafiee and Dinmohammadi present a fault tree diagram that outlines the standard failure modes, including wear of gearbox teeth, over-warming and abnormal vibrations. Additionally, a fault tree diagram describes a few potential modes of failure for rotor blades [51]. Thermal cycling has been described to cause 55% of converter failures, followed by vibration-induced failures at 20% by Sepulveda et al., considering that the power converter shows high failure rates [52].

Some risks are present under two different subsystems. For example, the YCT and RTR subsystems have bearings and the same risks under different codes. This is because despite the risks being the same,

[1] URL: https://brightspace.tudelft.nl/d2l/le/content/498709/viewContent/2937470/View [cited 24 May 2023]

yaw-bearing risks present more considerable consequences as only one yaw-bearing system supports the whole structure. In contrast, the rotor bearings only support their rotor, making their consequence less critical. Due to dividing the risk into multiple smaller subsystems, the rotor and drivetrain subsystems were mostly marginal risks as they only heavily affected the performance of one rotor assembly. Taking all the above into account, the identified technical risks of the project are laid out in Figure 7.1.

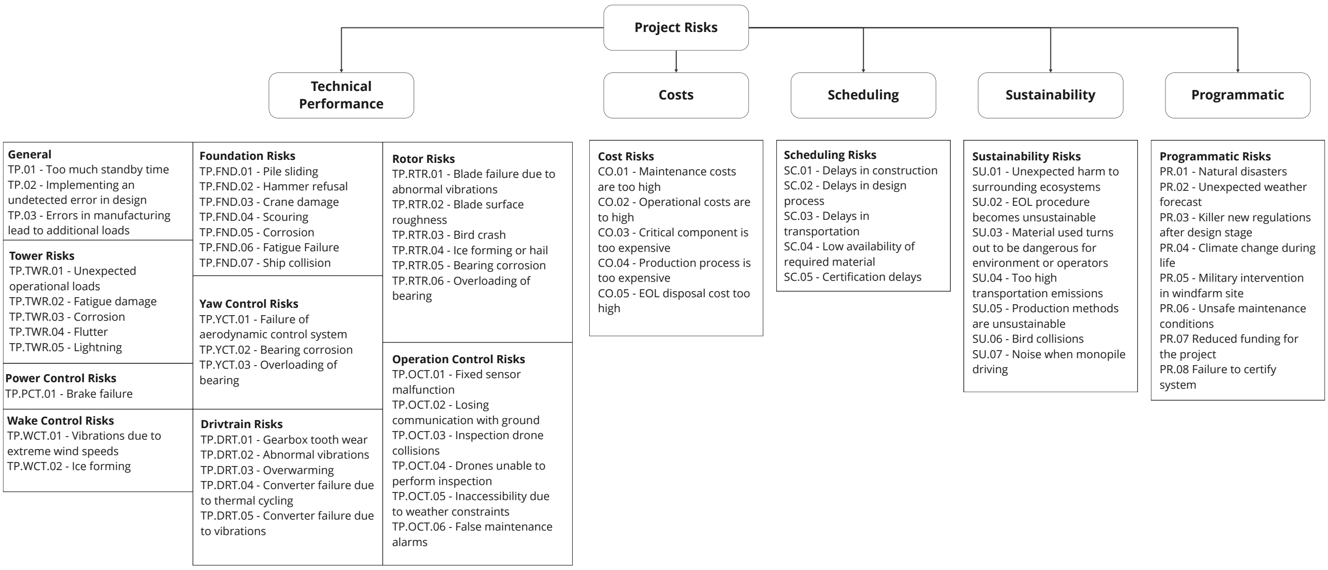


Figure 7.1: *Project Risks*

For each of these risks, the likelihood and consequence are predicted and added to the risk matrix in Figure 7.2. Risks newly added in the midterm phase of design after determining the conceptual design are highlighted in bold. These risks are subject to change and additions in the final design phase.

7.2. Risk management

Next, risk mitigation measures are determined for the risks with the highest combination of likelihood and consequence (risks in the top right corner of Figure 7.2).

Table 7.1: *Reasoning and mitigation for highest risks*

Risk	Reasoning	Mitigation
SU.01 - Unexpected harm to surrounding ecosystems	The wind farm may seriously impact the surrounding ecosystems. This would have catastrophic consequences leading to mission failure.	Study site ecology. Avoid fragile areas. Minimise system size. Minimise noise emissions
TP.PCT.01 - Brake failure	If a mechanical shaft brake fails, this could lead to overspeeding of the rotors during high winds, causing serious damage to the rotors. This risk is plausible during the brake's lifetime due to wear and tear.	Adding a redundant electrical braking system to the generators as in [53].
PR.06 - Unsafe maintenance conditions	Maintenance is a crucial element of a wind turbine design. It is a critical risk, therefore not to have safe maintenance procedures.	Apply a strict safety procedure for operators. Design for facilitated maintenance. Automate maintenance as much as possible. Minimise maintenance

PR.02 - Unexpected weather forecast	Weather conditions predicted by the control station to operate the turbines may be not fully correct. This may result in some turbines not operating at maximum efficiency.	Implement emergency procedures to prevent damage. Design for unexpected weather conditions.
SU.06 - Bird collisions	Bird populations can be reduced by wind turbine collisions. This is a big risk to the sustainability aspect of the project.	Minimise the size of wind turbine for power produced. Include sensors/deterrents for bird migrations. Turn off the turbine if bird migrations are detected.
TP.TWR.01 - Unexpected operational loads	The tower can suffer unexpected loads due to the failure of other subsystems, which introduce additional loads.	Design in accordance to standards that account for unexpected loads. Employ fail-safe mechanisms on other subsystems.
TP.TWR.03 - Corrosion	Corrosion of the tower structure is very likely due to high salinity in offshore conditions. This can negatively affect the material properties of the tower.	Use corrosion-resistant materials or paints. Monitor corrosion of vulnerable components.
TP.YCT.01 - Failure of the aerodynamic control system	Failure of the aerodynamic control system is critical as this heavily reduces the system's performance as it is not yawed towards the wind. This is also more likely to put it in unfavourable loading	Add a backup electrical yawing system.
TP.YCT.02 - Bearing corrosion	Corrosion of bearings is very likely to occur due to high salinity in offshore conditions. A corroded bearing has lower load capabilities and is more likely to fail. This is a critical risk since the yaw bearing holds the whole tower.	Use corrosion-resistant materials or paints. Monitor corrosion of vulnerable components.
TP.YCT.03 - Overloading of bearing	Overloading the bearing can lead to bearing failure, which not only leads to failure of the YCT but also reduces the bearing capability of withstanding tower loads, leading possibly to catastrophic failure	Oversize the yaw bearing. Add supporting elements to support bearing
TP.OCT.05 - Inaccessibility due to weather constraints	During extreme weather conditions accessing the turbine might not be possible; this is often the time when unscheduled maintenance is most likely to be needed, so a lot of damage can occur due to this risk	Add automatic shutdown algorithms to the turbine. Increase cameras/sensors to reduce the need for manual inspections.
TP.TWR.05 - Lightning	Lightning can cause damage to material and electrical components of the turbine and is the leading cause of unplanned downtime in wind turbines [54], leading to a much higher maintenance cost.	Include wind turbine grounding system. Construct blades with conductive material to avoid lightning arcs. Add surge protectors to electrical systems [54].
SU.05 - Production methods are unsustainable	Production methods will always produce at least a small amount of emissions. Therefore production methods will never be 100% green. Consequently, this is very likely to be present but, at the same time, marginal.	Optimise logistics. Use manufacturing methods that minimise waste. Employ lean production. Recycle waste

SU.07 - Noise when monopile driving	Monopile driving emits large amounts of noise, capable of killing marine life in the vicinity [55]. Since the monopile used is large, the noise level will be even greater.	Use bubble curtains while monopile driving. Pile driving with vibratory hammers [55].
TP.RTR.04, TP.WCT.02 - Ice forming or hail	Ice forming is almost certain due to the cold of the north sea; it can negatively affect the aerodynamics of the rotor and WCT and cause damage.	employ de-icing systems.
TP.DRT.04 - Converter failure due to thermal cycling	This is a likely failure mode for converters due to the different expansion coefficients of different materials in the converter [52].	Model thermal cycling and predict failure date for scheduled maintenance [52].

This mitigation leads to the post-mitigation risk matrix as seen in Figure 7.3:

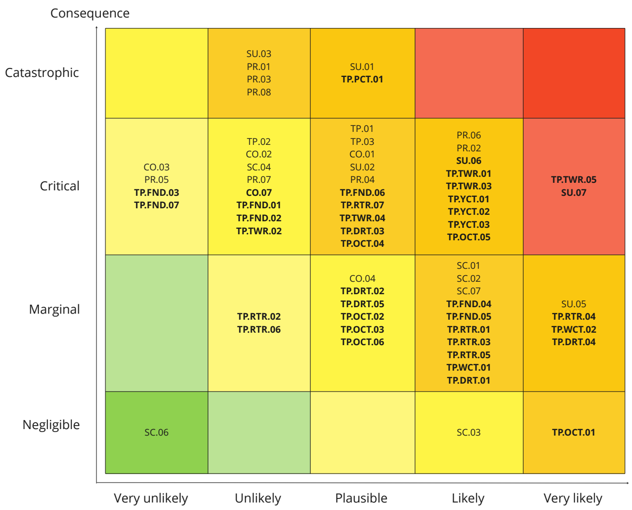


Figure 7.2: *Pre mitigation risk matrix*

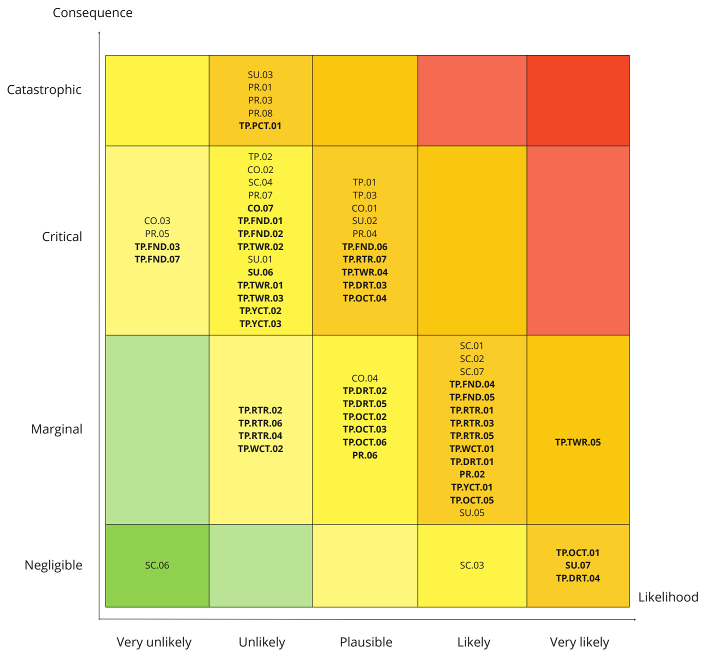


Figure 7.3: *Post mitigation risk matrix*

One risk remains in the high risk region, **TP.TWR.05**. This is the risk due to lightning. It is very difficult to avoid damage due to lightning in the lifetime of the system. Therefore, a contingency plan needs to be devised in order to limit the damage caused by this risk. After thunderstorms, the wind turbine should be manually inspected by the crew to determine if any damage has occurred. This is a form of unplanned maintenance that would decrease the operational duration of the wind turbine, but would extend its longevity by fixing any damage before it deteriorates. Replacing damaged electrical components is also necessary to ensure the turbine operates at its maximum capacity.

8
Performance Analysis

This chapter will give an overview of the expected performance of the design. The performance evaluation will mainly focus on the levelized cost of electricity, LCoE in short. The LCoE has been chosen as the performance metric since it can account for all aspects of the design, like expected power produced, changes in investments required and many more. Additionally, one of the user requirements was to lower the LCoE by 45%, therefore, it had to be evaluated anyway.

The chapter will begin with establishing the baseline LCoE for comparisons in Section 8.1. Next, the cost model description will be given in Section 8.2. In Section 8.3 the influence of the design on the LCoE will be discussed. Lastly, concluding remarks will be presented in Section 8.4.

8.1. Levelized cost of electricity for convectional Designs

To fully capture the advantages of the proposed design, a more holistic view at the LCoE is required. WindEurope has presented a plan to expand the production of electricity in the North Sea to 380 GW [2]. An expansion of this size with a traditional solution would mean using all of the very low LCoE (under 50€/MWh) as well as all of the low LCoE (between 50€/MWh and 65€/MWh) spots available in the North Sea. There also would be the need to put some wind turbines in the medium LCoE (between 65€/MWh and 80€/MWh) zones. The plan also specifies the amount of power planned per the cost bracket. For very low LCoE the projection is to install 112 GW, for low LCoE 264 GW and 4 GW at medium LCoE locations. With that information, the LCoE of the whole project can be calculated. It comes to 54€/MWh. This will be the benchmark for the project and the requirement to lower the LCoE by 45%, meaning the proposed design should achieve an LCoE of around 30€/MWh.

8.2. Description of the cost model

In order to give an estimation of all the costs involved with the wind turbine, the average cost breakdown of a traditional HAWT wind farm from the Offshore Renewable Energy Catapult was used [21]. The individual components of the cost breakdown were then updated based on various assumptions on how the new system differs from the HAWT wind farm model. These assumptions are discussed in Section 8.3. Each stage of updating the cost model based on the assumptions presents a new LCoE value. The costs in Catapult are broken down into turbine, balance of plant, development and project management, installation and commissioning, maintenance and service, operations and decommissioning. The Catapult offshore wind farm model assumes a 1 GW wind farm consisting of 100 10 MW wind turbines located 60 km from shore at a 30 m water depth. Thus, the differences between the Catapult wind farm concept and proposed wind farm concept affect the costs of individual components of the model. The costs are normalised to €/MWh to enable the costs to be compared without considering cost differences that are purely due to scaling. The annual electricity production (around 4471 GWh per year) (AEP) used in the LCoE has also been taken from the Catapult breakdown. The equation for LCoE, adjusted for inflation is given in Equation 8.1.

$$\text{LCoE} = \frac{\text{CapEx} + \text{OpEx} \cdot y_{\text{operational}}}{\text{Lifetime generated electricity}} \tag{8.1}$$

CapEx is the turbine's capital expenditure and balance of plant, installation and decommissioning, which are costs only incurred once. In contrast, OpEx is the operational expenditure which is mostly concerned with the operations and maintenance of the system and scales according to the system's lifetime. Therefore, the yearly OpEx can be multiplied by the system's lifetime to determine its effect on the final LCoE. The lifetime of the wind farm was assumed to be 25 years.

8.3. Cost impact of the proposed design

There are three cost-driving differences between the proposed design and the conventional option. These differences are expected to drive the lowering of LCoE and therefore need to be analysed with the financial model. The key differentiators are as follows:

- Better areas and cheaper O&M available, thanks to power density increasing from 5 MW/km^2 to 15 MW/km^2
- Changing from a conventional HAWT to a multi-rotor VAWT
- Use of wake re-energisation

Having established the model used and the performance goals (see Section 8.2, Section 8.1), the changes that will be applied and the feasibility of achieving the goals will be assessed.

The first modification that needs to be applied is the change in power density. The current optimum power density for wind farms is around 5 MW/km^2 [3]. The goal of the design is to increase the density to 16 MW/km^2. This would mean that wind energy's planned 380 GW would entirely fit in the very low LCoE. So, the change in density alone should drop the LCoE. Table 8.1 shows how the Catapult model has been adjusted for the change in power density. The table shows what parts will be impacted in terms of cost and how much they will need to change to achieve the targets. If a wind farm like that was possible, the LCoE would be around 36€/MWh.

Unfortunately, the change in the power density will have a negative performance impact. According to analysis performed by Ferreira, a traditional wind farm would lose about 35% of its electricity production [46]. This means that the LCoE would go back up to 53.5€/MWh.

The next step is to change the configuration of the wind farm from conventional single-rotor HAWTs to multi-rotor VAWTs. Changing the turbine design has huge implications for the cost model and should boost energy production slightly [46]. The design results and their influence on costs can be seen in Table 8.2. Similar to the previous table, Table 8.2 shows what will change in terms of cost and by how much w

The final LCoE is obtained by applying the effects of wake re-energization. The MR VAWT layout is conducive to placing large high-lift devices, which should recover the energy production to levels comparable with current wind farms [46]. This makes the final LCoE number around 31€/MWh, which is only 2% away from the required reduction. Keeping in mind that the majority of the predicated changes in costs are educated guesses, it makes the 45% reduction in LCoE possible.

Table 8.1: *Table showing the changes made to the Catapult model to account for benefits of a higher power density wind farm, whilst ignoring wake effects*

Name	Original Cost [GBP/MW]	Percentage Change	Modified Cost [GBP/MW]	Reason
Export cable	£130,000.00	-50.00%	£65,000.00	Closer to shore, less cable required
Array cable	£35,000.00	-50.00%	£17,500.00	Denser farm, less cables within the farm
Foundation cost	£150,000.00	-66.00%	£51,000.00	Shallower water, smaller foundation
Offshore electrical system	£45,000.00	-15.00%	£38,250.00	Denser farm, fewer separate components
Offshore facilities	£20,000.00	-15.00%	£17,000.00	Denser farm, more centralized facilities
Offshore substation structure	£60,000.00	-33.00%	£40,200.00	Shallower water, less structure needed
Development and consenting services	£50,000.00	-33.00%	£33,500.00	Better understood regions, easier development
Environmental and metocean surveys	£8,000.00	-20.00%	£6,400.00	Denser area, smaller area to analysis
Foundation installation	£100,000.00	-60.00%	£50,000.00	Closer to shore, denser farm less rent time on equipment
Offshore substation installation	£35,000.00	-50.00%	£17,500.00	Closer to shore, less rent time on equipment
Cable burial	£20,000.00	-60.00%	£8,000.00	Closer to shore, denser farm, less cable to install
Cable pull-in	£7,500.00	-60.00%	£3,000.00	Smaller area of operation, less rent time on equipment
Other (cable-laying vessel, seruvey works, etc.)	£186,000.00	-60.00%	£74,000.00	Smaller area, closer to shore, less rent time on equipment
Turbine installation	£50,000.00	-36.25%	£31,875.00	Shallower water, denser farm easier and quicker installation
Sea-based support	£2,500.00	-52.00%	£1,200.00	Smaller area of operation
Maintenance of turbine	£33,000.00	-50.00%	£16,500.00	Smaller area of operation, less time spent traveling
Maintenance of balance of plant	£18,000.00	-40.00%	£10,800.00	Smaller area of operation, less time spent traveling
Operational offshore logistics	£1,600.00	-30.00%	£1,120.00	Smaller area of operation
Turbine decommissioning	£45,000.00	-40.00%	£26,775.00	Smaller area of operation, closer to shore, less moving
Foundation decommissioning	£75,000.00	-42.00%	£42,712.50	Smaller area of operation, closer to shore, less moving
Cable decommissioning	£140,000.00	-60.00%	£56,000.00	Less cable to decommission
Substation decommissioning	£65,000.00	-30.00%	£45,500.00	Closer to shore, less traveling
LCoE [EUR/MWh]	**€ 47.36**		**€ 35.81**	

Table 8.2: *Table showing the changes mode to the Catapult model based on changing from a traditional HAWT to a MR VAWT turbine design, including the wake losses*

Name	Tradition design [GBP/MW]	Percentage change	New design [GBP/MW]	Reason
Bedplate	£20,000.00	-100.00%	£-	Generator attached directly to structure
Main bearing	£20,000.00	-25.00%	£15,000.00	Smaller bearings
Main shaft	£20,000.00	-33.00%	£13,400.00	Higher RPM, lower torque
Gearbox	£70,000.00	-50.00%	£35,000.00	Higher RPM, lower torque
Generator	£100,000.00	-33.00%	£67,000.00	Higher RPM, lower torque, less weight optimized
Power take-off	£70,000.00	-10.00%	£63,000.00	Less weight optimized
Control system	£25,000.00	50.00%	£37,500.00	Higher complexity
Yaw system	£17,000.00	100.00%	£34,000.00	Whole structure yaw, higher loads
Yaw bearing	£7,000.00	100.00%	£14,000.00	Whole structure yaw, higher loads
Small engineering components	£25,000.00	50.00%	£37,500.00	More complex strucutre
Structural fasteners	£7,000.00	300.00%	£28,000.00	Significantly more connection points
Blades	£130,000.00	-80.00%	£26,000.00	Much simplified, lower bending
Hub casting	£15,000.00	-75.00%	£3,750.00	No need for highly optimized part
Blade bearings	£20,000.00	-50.00%	£10,000.00	Less forces on bearings
Pitch system	£10,000.00	-50.00%	£5,000.00	Simplified blade pitching
Fabricated steel components	£5,360.00	-33.00%	£3,591.20	No need for highly optimized part
Tower material cost	£60,000.00	100.00%	£120,000.00	More structure per MW
Tower internals	£7,000.00	100.00%	£14,000.00	More onboard systems to facility maintenance
Other (includes assembly, warranty, etc.)	£340,000.00	20.00%	£408,000.00	More complex assembly
Array cable	£17,500.00	-25.00%	£13,125.00	Fewer turbines
Transition piece	£100,000.00	50.00%	£150,000.00	Heavier structure
Corrosion protection	£20,000.00	25.00%	£25,000.00	More exposed steel
Foundation cost	£51,000.00	25.00%	£63,750.00	Much bigger foundation, fewer of them
Development and consenting services	£33,500.00	100.00%	£67,000.00	Novel design, more development required
Foundation Installation	£40,000.00	-33.00%	£26,800.00	Fewer foundations to install
Cable burial	£8,000.00	-15.00%	£6,800.00	Less cable
Cable pull-in	£3,000.00	-30.00%	£2,100.00	Few turbines
Other (cable-laying vessel, seruvey works, etc.)	£74,400.00	-15.00%	£63,240.00	Less cable and fewer turbines
Turbine installation	£31,875.00	-20.00%	£25,500.00	No need for specialized equipment
LCoE [EUR/MWh]	**€ 53.47**		**€ 47.82**	

8.4. Conclusion from the cost model

Based on the analysis done in Section 8.3 it is clear that the proposed design has an immense impact on the LCoE. Please note that the "Other" element in Figure 8.1 and Figure 8.2 refers to around 40 small cost items. Looking at Figure 8.1 and Figure 8.2 the new design has de-emphasized the most problematic parts of the wind farm. The maintenance cost has dropped from 27% of LCoE to 11%, meaning the proposed design should drop the maintenance costs by half, to achieve the desired LCoE. It is also worth noting that the cost reduction is severe enough that the wind turbine costs that can not be easily influenced are becoming the largest costs. As an example, the insurance costs are not expected to change between the traditional and new designs, but the reduction in the total costs means the insurance costs become 50% more influential. This suggests that it might be difficult to hit the required targets unless the predicted price changes materialise. In other words, the pricing model is quite sensitive.

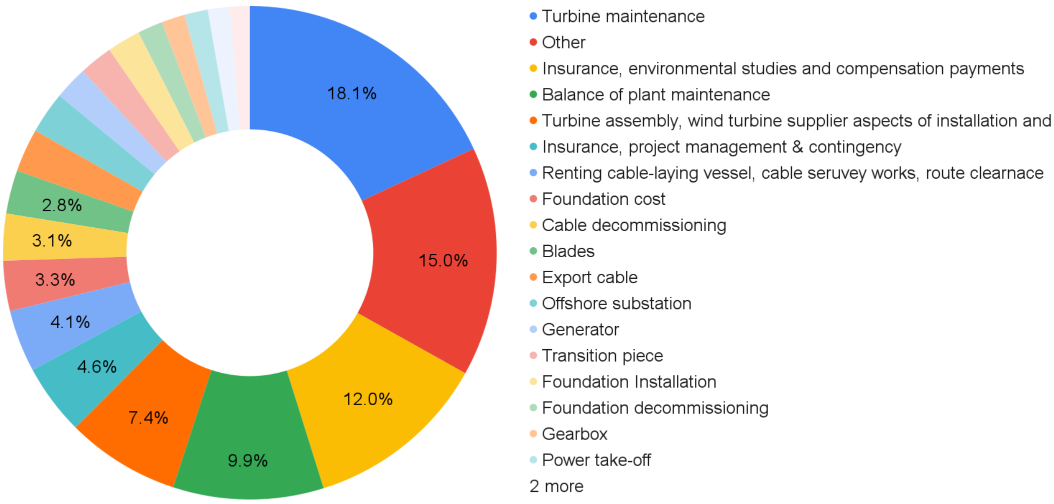


Figure 8.1: *Percentage breakdown of the cost associated with different wind farm elements for the Catapult reference wind farm*

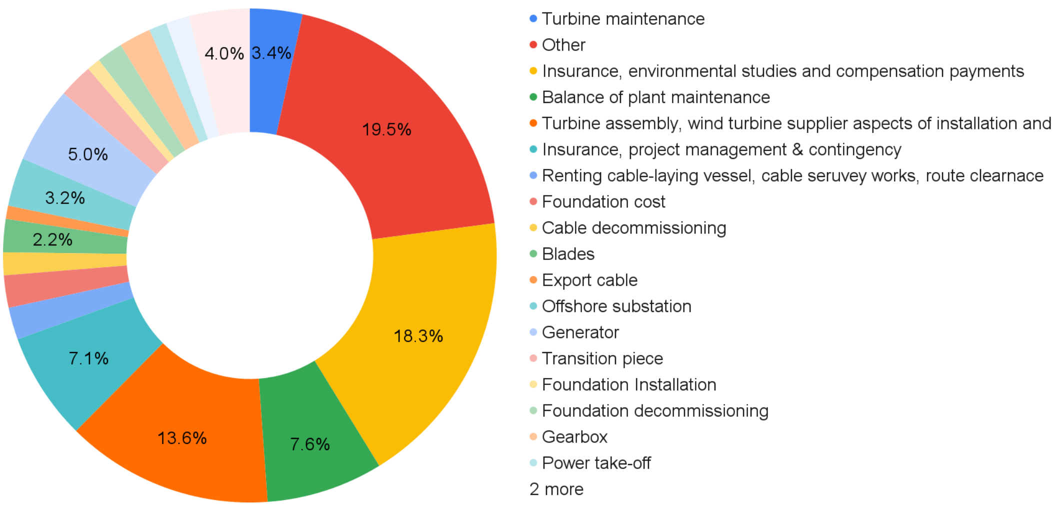


Figure 8.2: *Percentage breakdown of the cost associated with different wind farm elements for the proposed wind farm design*

9
Sustainability Strategy

In this chapter, the sustainability strategy is presented. The scope of this chapter addresses both the way sustainability is taken into account in the design and the way the product or system contributes to sustainability. Section 9.1 discusses how the design contributes to sustainability, then Section 9.2 discusses materials and manufacturing concerns with regard to sustainability. Section 9.3 discusses how sustainability can be improved during the operations phase, Section 9.4 describes how the end-of-life process can contribute to sustainability, and finally Section 9.5 discusses some noise and bird-life related concerns.

9.1. Sustainability contributions

GHG (Green House Gas) emissions are a critical environmental issue. To reduce global emissions, energy generation will increasingly have to be done using 'greener' methods. To accomplish this, the amount of wind energy generation systems is expected to increase, with an exponential increase in required space for offshore wind power [1].

While the north sea is a large area, there is more activity than there seems to be at first sight, and these operations such as fishing and shipping, along with ecological concerns and the suitability of certain areas for wind farm development do not leave much space for wind turbines. Recently plans to build wind farms at two sites in the north sea previously designated for offshore wind developments, were canceled as investigation showed they were less suitable due to potential effects on the ecosystem, fishing, and shipping [2].

Given the limited amount of space, to maximize the total amount of generated wind energy, the power density of the turbine should be maximized. By using wake re-energisation, the MRS-VAWT to be designed is expected to achieve a power density of 15 MW/km^2, a significant increase from some of the most power-dense systems currently in use at around 5 MW/km^2[3].

9.2. Materials and manufacturing

Given the materials being considered for the design it is important to take into account how sustainability will affect these choices. Yang and Chen and Mendecka and Lombardi estimate that the raw materials used are responsible for 50 % to 70 % of the $CO2_{eq}$ emissions of wind turbines [4] and [5].

One way to reduce these emissions is to use materials that emit fewer greenhouse gasses during production and refinement. This includes both the manufacturing and the transportation of materials. Therefore the materials should be sourced an manufactured locally as much as possible.

These emissions can also be reduced by recycling the materials. Currently, Vestas assures its customers that up to 85% of the mass of their current turbines are recyclable [3]. Yet, the monopile of conventional HAWT, which is made mostly of fully recyclable materials such as steel and cast iron, accounts for most of the turbine's mass. The main remaining problem is the other 15 % of the turbine mass which is mostly made up of the turbine blades. These are made of GFRP and other fiber-reinforced composites. As there is no large recycling industry for these composites, these are currently either landfilled or incinerated [43]. To increase sustainability, metal rotor blades will also be considered in the rotor material trade-off. Although they are not currently in use for industry HAWT of comparable size to the current design, given

[1]Source: https://www.dnv.com/oceansfuture/spatial-competition.html [Cited May 2023]
[2]Source: https://english.rvo.nl/information/offshore-wind-energy/offshore-wind-energy-plans-2030-2050 [Cited May 2023].
[3]URL: https://www.vestas.com/en/sustainability/environment/zero-waste [cited May 2023]

the differences in loading and support structure between the VAWT design and HAWT design they will be considered.

An LCA approach proposed by Mendecka and Lombardi will be used to measure the environmental impact of the turbine [5]. This model includes equivalent $CO2$ emissions for global warming potential, equivalent $SO2$ emissions for acidification potential, and equivalent $PO4$ emissions for eutrophication potential.

Rare-earth metals

PMG generators common in wind turbines make use of permanent magnets, made of rare-earth metals. With the explosive growth of wind energy generators, the global demand for these metals is expected to rise to 13-31x of the current demand (depending on the specific metal), while the world supply of these materials is limited, with China being responsible for 80% of the worldwide production [28] [29]. For this reason, the choice was made to use a DFIG generator with a three-stage gearbox. This generator type uses electromagnets instead of permanent magnets, avoiding the use of rare-earth metals.

9.3. Operations

A practical and reliable maintenance strategy must be planned as it is crucial to OWTs' operations. Commonly utilized maintenance techniques are: reactive, preventative, and predictive. Reactive maintenance is carried out after the failure has already happened, which is not desired since OWTs have high failure rates with low system reliability. Once a small failure is noticed late, it can evolve into a major failure resulting in unwanted downtime, and a possible need to replace the parts which will affect emissions negatively. Proactive maintenance is where scheduled inspection and replacement is carried out before failure to prevent minor faults from developing into a major failure. Major failures (only 25% of all failures) contribute to 95% of downtime[56]. However, because the working environment of OWTs' is very chaotic and destructive, modeling for the decision of the maintenance intervals is not precise. Therefore, the visits need to be more frequent than required; this may generate more emissions than predictive maintenance because of the involvement of large crews and vessels. Predictive maintenance is where loads of data from the different subsystems of the OWT are collected to assess the situation of the structure. With this method, emissions can be pushed to the lowest, requiring maintenance only when indispensable. Therefore parts that are most prone to failure described above need to be equipped with onboard sensors such as ultrasonic, thermal, accelerometer, oil pressure, oil particulate, voltage, and temperature sensors.

Adopting more efficient maintenance arrangements can reduce GHG emissions produced by grid connection and maintenance activities. A significant reduction in the GHG produced during transport can be achieved using alternative shorter transport routes and utilization of warehouses closer to the farm with the replacement parts. A case study showed that CO2 emissions associated with the transport of OWTs and their components could be reduced by 33% with reasonably shorter transport routes; however, the operation only accounts for a very small portion of the emissions [57].

The use of steel and the replacement of OWTs make up a more significant proportion (3% planned, 47% unplanned) of the GHG emissions during operation compared to vessel transportation [58]. Of this amount, approximately 33% of the GHG emissions result from using specialized vessels to replace large components. At the same time, CTVs and helicopters account for only a minor part. Therefore, from a sustainability perspective, limiting the use of specialized vessels is beneficial. As the MRS-VAWT design allows for the use of smaller individual components, the use of specialized vehicles may be reduced.

A large percentage (46%) comes from producing and decommissioning lubricants and spare parts. Because failure rates determine the need for transportation and consequently affect fuel consumption, they are directly related to GHG emissions. Since the rotor and drivetrain rotate and the structures are exposed to corrosive seawater, the failure rates are frequently caused by wear and fatigue during operation. Some failures are considered to happen randomly without explicit trends and predictions. The major failures of these components and possible design requirements for sustainability are listed following [56]. By reducing the likelihood of these failures happening, the emissions can be reduced:

- Blade: deterioration, adjustment error, blades corrosion, crack, and severe aeroelastic deflections [59][60][61]; the likelihood of this failure is reduced because the VAWTs have a lower tip speed ratio than conventional wind turbines. As impact energy scales with V^2, this will significantly lower the damage done to the blades by rain or other particles.
- Shaft: shaft imbalance, shaft misalignment, shaft damage, and broken shaft [62]; shafts may be overdesigned to reduce the required maintenance.
- Gearbox: wearing, fatigue, pitting, gear tooth damage, braking in teeth, the eccentricity of toothed wheels, displacement, oil leakage, insufficient lubrication, high oil temperature, and poor lubrication [63]; as the turbine design places all the gearboxes at the bottom of the structure, they may be oversized to reduce required maintenance.
- Generator: overspeed, overheating, wearing, excessive vibration, rotor asymmetries, bar break, electrical problems, insulation damage, slip rigs, winding damage, and abnormal noises [64]; as the turbine design places all the gearboxes at the bottom of the structure, they may be oversized to reduce required maintenance. In addition to this, since multiple rotors are connected to a single generator, there are fewer points of failure.
- Bearings: overheating, spalling, wear, defect of bearing shells, and bearing damage [65]; this is mainly mitigated by overdesigning the bearings.

9.4. End of life

According to the EPA, the average life span of a conventional HAWT wind turbine accounted for 20 years in 2013 [66], given that the turbine is regularly inspected once every six months. This rather short life span for an electric production system is mostly due to the very high loads experienced during its lifetime. Conventional HAWT can operate in very high winds, up until a cut-out limit where the wind turbine is decelerated and parked to avoid structural failure.

An attractive end-of-life option to increase sustainability is repowering the turbine. After investigating the condition of the turbine and the state of the equipment, usually the rotor and nacelle are replaced by new more modern alternatives that yield more energy. Considering that the majority of emissions associated with wind turbines come from the raw materials that go towards it, repowering the asset and prolonging its life for an additional period of 20-25 years would decrease the $CO_{2_{eq}}$ emissions per MW produced and increase the associated Energy Return on Investment (EROI).

The repowering of an asset implies the removal of large parts and subsystems, the rotor and nacelle to name a few. Thus, there is a general requirement to use High Lifting Vehicles (HLV), in order to detach and transport these large subsystems, so that they can be dismantled and recycled or reused onshore. Apart from the high costs associated with renting such a vehicle, the emissions and the disturbance to the local marine life that these HLVs produce are not negligible. The use of a multi-rotor system may heavily influence these operations, as a modular design with smaller dimensions and lower mass could circumvent the use of HLVs and improve the sustainability of turbine repowering. Especially since the heavy drive train components are located at the bottom of the structure.

Once the used wind turbines are removed, they are sent onshore in order to be properly dismantled. The recyclable components of the turbine will then be recycled, and the rest is landfilled.

Another tactic to approach the prolonging of the operation phase of the project life is through life extension. Although similar to repowering, life extension differs in its degree of replacements and repairs. After the necessary structural, fatigue, and environmental studies, decisive action is taken to perform minor to low-cost repairs and replacements so that the lifetime of the asset is prolonged another 5-10 years. This method presents itself as one of the least emissive lifetime extension options for the asset, from the standpoint of the use of vessels and personnel [67]. This again benefits from the multirotor concept, due to the modularity of the design, and the fact that all components are more accessible than in the nacelle of a traditional wind turbine.

9.5. Ecological impact

Bird impacts

Multiple technical reports [68] and papers exist that have focused on the actual environmental effects of wind turbine systems on birds in a specific site. One of them, particularly, is relevant to the current project and focuses on the interested area of the Dutch North Sea. This paper sets up a model based on the information provided in Rijkswaterstaat's Framework for Assessing Ecological and Cumulative Effects [69].

With the aim of calculating the population-level effects of bird collisions in offshore wind farms for a number of relevant bird species. The study was based on several wind turbine farms spread all over the Dutch North Sea, whose details were provided by Rijkswaterstaat. Most of them are HAWT farms, and the simulated scenarios are based on already existing and future projects up to 2030. The number of victims was first estimated for each wind farm and then summed over the wind farms according to the different scenarios.

This study can be considered a starting point for refining a project-specific population-level impacts model based on the different wind turbine farms considered in the paper. The idea is to use the results mentioned in this paper and compare them with the future final design of this project to see if the results overlap. Based on this, a correction of the model can be performed in order to have an accurate overview of the impact that our design might have on the local wildlife. Once the effects on birdlife are known, mitigation measures can be further explored.

Noise impacts

The noise pollution produced by the wind turbine is another aspect that can be examined for the sustainability strategy. There are two methods by which noise can be generated. The first one refers to the installation phase, where the entire assembly is set up. Usually, the main source is the pile-driving. The second one is related to the operation phase when the system is actively working. Nevertheless, this should not be a problem since the resulting sound is proportional to the tip speed ratio. The aimed TSR for the designed vertical wind turbine is about four to five, which is lower than for a horizontal one, which has approximately six to eight or even larger numbers [4].

The operational noise cannot be considered a problem as a result of the low TSR. However, there are two types of noise that can be identified during the operation of the system: the aerodynamic one which reflects the interaction of the flow with the blades particularly, and the mechanical one which indicates the sound produced by the moving parts of the mechanism, in particular gearboxes and shafts.

The sound produced while operating is propagated from the tower to the foundation and then further into the water. The noise generated by a regular turbine cannot be heard below 20 m. As a consequence of this, no strategy will be adopted for diminishing it.

[4] URL: http://www.reuk.co.uk/wordpress/wind/wind-turbine-tip-speed-ratio/ [cited 22 May 2023]

10 Conclusion

This report mainly consisted of the trade-off design phase of the project. The system was divided into several subsystems, performing a trade-off for each to determine a suitable conceptual design. A total of six trade-offs were made between the possible options to be used for the design. The trade-off resulted in commercially sized vertical axis wind turbine rotors using a drive train with a gearbox, a doubly fed induction generator (DFIG), and a partial converter, supported by a fixed monopile foundation and being yawed by an aerodynamic system, with an electric yaw system as a backup. Sensitivity analysis showed that some of these options may need to be reconsidered if user requirements were to change.

An analysis of risks resulted in harm to wildlife, lightning, and structural and electrical component failures being potential high system risks. Mitigation plans based on employing alternative technologies, increasing redundancy and emergency procedures were proposed to be considered in the final design.

Predictive maintenance will be used to reduce operating costs and downtime, but this requires a lot of sensors and monitoring. Large spare parts will be stored in a central depot, and smaller parts can be stored on-site. The performance of the design was evaluated based on the levelized cost of electricity (LCoE). A detailed breakdown of the cost for the wind farm was used to compare how the proposed design would compare to conventional solutions. It is clear from the LCoE calculations that the design has the potential to be significantly more profitable than traditional HAWT-based wind farms.

The turbine concept contributes to sustainability by increasing power density and thereby increasing the amount of green energy that can be generated in the limited available space. In addition to this, it will be designed to be as recyclable as possible by mainly using steel alloys. The different metals will be considered. Due to the MRS-VAWT concept with generators and gearboxes at the bottom, the drive train components may be oversized to reduce the required amount of maintenance and, therefore, the emissions from transport. As DFIG generators will be used, rare-earth metals are avoided.

This report sets up the necessary considerations to begin the final design stage of the project. The individual subsystems will be further designed after the system configuration has been determined. A preliminary location for the wind turbine will be determined, and the profile of the rotors (H, V, Φ) will be set. The number of shafts and rotor diameter will be determined more accurately. The location of the wake management system will be established, and the airfoils for the wake management system and the rotors will be chosen. A two-rotor generator option will be evaluated. Finally, a detailed simulation will be made to calculate detailed structure dimensions.

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