TKI WIND OP ZEE
Topsector Energie

Optimal offshore wind turbine size and standardisation study

By DNV Services UK Ltd

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May 2022

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1 Executive Summary

The rapid growth in offshore Wind Turbine Generator (WTG) size is expected to slow down in the coming years. This is the main conclusion based on the combined numerical and qualitative assessment presented in this document.

DNV does not see any technical limitation for WTGs to grow in size beyond the current largest offshore WTG designs, but numerical analysis shows that further growth does not result in lowering the Levelised Cost of Energy (LCoE). Sensitivity analysis applying different future learning rates shows that direct cost reduction has much more potential to lower LCoE.

In the current fast-growing offshore wind market, increasing WTG production numbers offers the opportunity to reduce costs. Larger production numbers generally allow for larger investment in product and production optimisation (standardisation and industrialisation, transport, installation, servicing), and larger production numbers offer benefits in economies of scale (e.g., larger orders). To take advantage of this, the industry needs to shift focus from new product development to product improvement, and up-scaling and optimisation of manufacturing processes.

The numerical analysis performed and presented in this document provides insight into optimal WTG configurations for given offshore site conditions. The cost of energy is found to increase with WTG rating. Lower rated turbines, 12-15MW, with high specific power densities (400-450W/m2) are found to be the most cost-optimal. For high specific power densities, the LCoE is found to show no significant variation with respect to WTG rating in the range of 12-20 MW. This indicates that the choice of optimal turbine configuration is not straightforward and may depend on parameters other than WTG rating and rotor diameter. Therefore, several sensitivity analyses have been performed to investigate the impact of different site conditions (e.g., mean annual wind speed and wind speed distribution), discount rates, O&M (Operations and Maintenance) modelling assumptions and WTG design choices on LCoE. It is found that site conditions and discount rates have a strong influence on the cost of energy. Turbine design choices like design tip speed ratio and drivetrain configuration impact the LCoE to a lesser but still significant extent. The LCoE is also sensitive to O&M modelling assumptions. While predicting to what extent O&M costs will reduce with increasing WTG rating is difficult, this can have a significant impact on the selection of optimal WTG configuration. The goal of the provided LCoE values in the different sections of this report is to make relative comparison possible. Although the aim is to provide realistic LCoE values, these values should only be considered indicative and not an exact representation of actual bid values.

Based on the performed assessments, DNV expects that up to 2030-2035 leading offshore WTG manufacturers will mainly focus on their current largest design WTG platforms and future upgrades that enable small growth steps. It is expected that the platform lifecycle ends with 14-18MW range platforms carrying rotors with diameters in the range of 230-250m.

After 2030-2035, it is expected that next-generation WTG platforms will be introduced with a limited increase in size compared to the platforms they replace. These new WTG platforms will however be highly cost optimised, feature many new technologies and will be operated and maintained following new strategies. WTG sizes are expected to go up to 18-24MW with rotor diameters in the range of 250-265m.

LCoE values are sensitive to several influential factors for which best estimates were made but could change over time. Examples of these are the cost price of raw materials and labour, discount rates and Operational Expenditures (OpEx). Significant future changes in any of these factors can influence conclusions on optimal WTG size.

2 Introduction

The Netherlands Enterprise Agency (RVO) (“the Customer”) has awarded DNV Services UK Ltd (“DNV”) a study on “Optimal offshore wind turbine size and standardisation” for the Top Consortium Knowledge and Innovation Offshore Wind (TKI Wind op zee). In the TKI Wind op Zee innovation programme and the first mission-oriented innovation programme (MMIP1) formulated by the Ministry of Economic Affairs and Climate Policy, a number of bottlenecks have been identified which could obstruct the large-scale roll-out of offshore wind energy.

Over the past decade, the industry has witnessed rapid growth in offshore WTG size (in terms of power rating, rotor diameter and hub height) in combination with a rapid fall in Levelised Cost of Energy (LCoE). The large offshore WTGs currently entering the market were not designed overnight, but are a result of many incremental growth steps, applying lessons learned and new technologies at every step of the way. This study aims to explore where this growth is likely to continue and what will ultimately constrain it. DNV has been involved in a number of projects exploring this including the Innwind EU project /2/, and other projects for commercial customers (WTG manufacturers, developers and investors) and aims to bring this experience to the project.

The core questions to be addressed in this study are:

1) Where will this growth continue (in terms of WTG size and power rating) and what will ultimately constrain it?
2) How much potential is there for standardisation and industrialisation for future offshore WTGs including consideration of potential societal benefits?

These are further split into the below-mentioned objectives:

2.1 Objectives

The objectives of this study were to:

- Indicate how the LCoE of offshore wind energy will develop with a further increase in capacity per WTG, including the costs of all elements in the value chain and life cycle.
- Indicate the impact on the supply chain and required investments in e.g., vessels, installation equipment, and port infrastructure to transport and install and maintain these WTGs and wind farms. Options to automate and robotise installation, inspection and maintenance may play a role.
- Indicate the missed benefits of standardisation and economies of scale in the design and production of the main components of WTGs as a result of the current rapid increase in the capacity of WTGs. Also take into account the effects on the economic life of, for example, installation ships and installations.

- Indicate which standardisation and economies of scale can be achieved by maximizing the future capacity of WTGs at a certain level.
- Indicate which physical limits (for instance by properties of materials) apply to the current concept of horizontal axis WTGs as is applied in most offshore wind parks.
- Indicate what is the optimal capacity size of WTGs, against the background of the previous analyses of the impact of increasing WTG size on all links in the supply chain and taking into account variations in local conditions.
- Reflect on potential societal benefits of standardisation for safety, circularity, and human capital.

2.2 General execution strategy

DNV has answered the questions formulated in Section 2.1 by using a two-step approach: a numerical analysis followed by a qualitative study.
In the numerical study presented in Section 3, a database of WTG results was created (geometric, mass and cost data results) using DNV's internal cost modelling tool for wind power, Turbine.Architect. This involved:

1. Selecting plausible environmental conditions representative of current and future leading offshore markets.
2. Estimation of future offshore WTGs' headline parameter envelope in which the optimal size WTG is expected to be captured, unrestrained from any currently anticipated technology bottlenecks.
3. Understanding sensitivity of the cost of energy to main driving parameters.

Turbine.Architect was used to numerically investigate very large size WTGs using the tool's engineering and scaling models, but potential technology and practical limits likely to arise in the future were not considered. The tool works on the assumption that it is always possible to design bigger WTGs. For this reason, in the sections following the numerical analysis, future WTG growth is evaluated using the numerical results in combination with other influential factors not considered in the numerical analysis. The following factors are used in this qualitative assessment:

- Historic WTG growth
- Technology limitations
- Standardisation and industrialisation
- Economies of scale
- Societal benefits

Based on the combined numerical and qualitative study, overall conclusions will be drawn on the expected future sizes of offshore WTGs.

2.3 Abbreviations

Table 2-1: Abbreviations

Abbreviation	Description
BoP	Balance of Plant
CaPex	Capital Expenditure
CLR	Cost Learning Rate
DFIG	Doubly Fed Induction Generator
DTRB	Double Tapered Roller Bearing
ETO	DNV's Energy Transition Outlook
FTE	Full-Time Employed
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IRR	Internal rate of return
JU	Jack-up (vessel)
LAT	Lowest Astronomical Tide
LCoE	Levelised Cost of Energy
LIDAR	Laser Imaging Detection And Ranging
MDAO	Multi-disciplinary analysis and optimization
MSL	The mean sea level
NPV	Net Present Value
O&M	Operation and Maintenance
OECD	Organisation for Economic Co-operation and Development
OpEx	Operational Expenditure
PMG	Permanent Magnet Generator
R&D	Research and Development
RNA	Rotor Nacelle Assembly
RVO	Rijksdienst voor Ondernemend Nederland
SES	Surface Effect Ship
SOV	Service Operations Vessel
TRB	Tapered Roller Bearing
TSR	Tip Speed Ratio
WSTRB	Widely Spaced Tapered Roller Bearings

WTG	Wind Turbine Generator
WTIV	Wind Turbine Installation Vessels

3 Numerical study on future offshore wind turbine size and cost

The main goal of this numerical study using DNV's in-house cost-modelling tool, Turbine.Architect is to identify how LCoE will evolve as WTG sizes grow including the impact of future cost learnings and technology evolution. In this section, we seek to answer what WTG sizes and technologies are likely to be most optimal from a purely cost of energy perspective.

3.1 A brief introduction to Turbine.Architect cost modelling tool

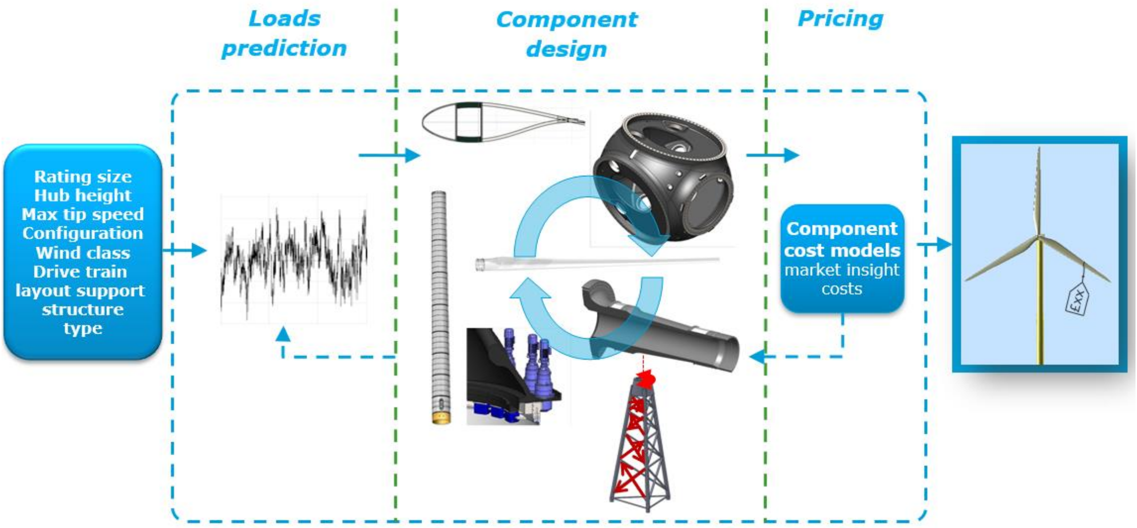
Turbine.Architect is DNV's in-house engineering and cost modelling tool for wind energy that runs on the Renewables.Architect MDAO (Multi-disciplinary analysis and optimization) framework and comprises a suite of models that enables the accelerated design of WTG components and cost estimation.
The strength of Turbine.Architect is that it combines the speed of analysis with an accuracy which makes it possible to develop high-level insights into parameter sensitivities. It enables the identification of optimum designs and configurations from a large dataset of generated WTG designs and costs. It is a flexible tool with analysis and results customized to customers' needs within reasonable limits. The main pillars of the Turbine.Architect platform are:

- DNV's WTG loads database
- Extensive WTG engineering models based on DNV turbine engineering knowledge and skills
- Cost data

The tool combines inputs of headline WTG parameters with design loads and iterates the design of the main WTG components according to engineering design principles and DNV's experience, to generate a WTG design tuned to the input load envelope. Turbine.Architect iterates on the dimensions of the components according to the input load envelope, ensuring that the final design withstands both fatigue and extreme loads as well as satisfies other applied constraints. The results from Turbine.Architect are continuously verified against available industry data to ensure the sub-models and assumptions remain up to date.

All WTGs/foundations in the analysis are modelled based on generic WTG/foundation designs for specified loading and environmental conditions, using in-house engineering models for components in Turbine.Architect as shown in Figure 3-1. Using generated WTG and foundation design outputs, such as component masses or power rating, component costs are estimated based on DNV experience in wind power projects. Combined with site-specific wind conditions and an assumed layout, the designed WTGs are used to estimate the wind farm Capital Expenditure (CapEx), Balance of Plant (BoP), Operational Expenditure (OpEx) and energy production.

Figure 3-1: Turbine.Architect turbine design and costing methodology.

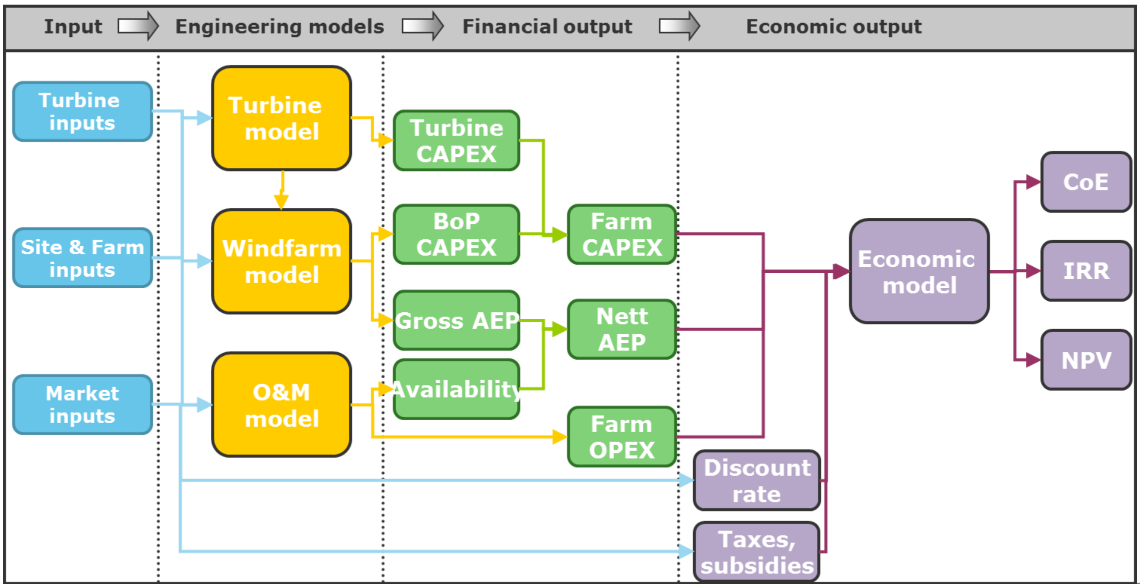


The potential success of WTG concepts is typically not measured in engineering metrics, such as rating, mass or even energy capture and costs, but in economic metrics. DNV's Turbine.Architect engineering and cost modelling software can calculate the relative financial attractiveness of wind farm configurations, in terms of the following metrics:

- Levelised Cost of Energy, LCoE,
- Internal rate of return, IRR, or,
- Net Present Value, NPV.

The calculation of these parameters is achieved by linking several engineering and financial models, as illustrated in Figure 3-2.

Figure 3-2: Schematic flow diagram of farm-level cost modelling in Turbine.Architect



It should be noted that the Turbine.Architect tool performs calculations and outlines the design of each part of an offshore wind farm, taking account of site conditions and key project cost drivers based on generic design approaches, best estimate unit costs and engineering principles. There is, therefore, uncertainty in the results arising from both unavailability of information, for example with respect to site-specific foundation design; and economic and commercial factors such as supplier profit or vessel selection. These uncertainties could be reduced through the use of more detailed input information, and/or site-specific studies; however, there will remain some uncertainty in the results until a detailed engineering design is undertaken. Even so, DNV has endeavoured to ensure that the predictions for CapEx components and OpEx are realistic. For instance, absolute average turbine prices are obtained by scaling the Turbine.Architect predictions to aggregated prices that DNV has observed on recent, comparable European wind power projects. A similar approach is applicable for foundation costs.

3.2 Numerical analysis approach

Turbine.Architect was used to modeling a range of different WTG configurations with varying WTG ratings, rotor diameters, drivetrain configurations, blade design tip speed ratios (ratio of blade tip velocity to incoming wind velocity), discount rates and learning rates. In total, 8208 different scenarios, including variations on turbine configurations (turbine ratings from 12 - 30MW, and rotor diameters from 184 – 357 m) and site conditions, are modelled in Turbine.Architect. Modelling such an expansive design space allows us to state with a high level of confidence that the optimal design envelope would lie within the modelled design space.

The baseline analysis was performed for a 1000 MW capacity wind farm situated in the Dutch waters in Ijmuiden Ver (IJV). The intention was to base the analysis on a typical offshore site in the North Sea with excellent wind resources, where large WTGs are likely to be installed in the future. IJV is likely to go under development before 2030 /5/. Moreover, soil, wind and metocean data for the site are made publicly available by RVO /6/. The following sub-sections describe the choice of fixed and variable inputs as well as other modelling assumptions made for this analysis.

3.2.1 Site conditions

A single set of average wind, metocean and soil conditions are assumed for the whole site spreading over 400 km2 /5/. These assumptions are based on publicly available data for the site and DNV's experience in WTG modelling, particularly in the European market and the North Sea.

The wind conditions for the site are summarized in Table 3-1. Note that a detailed wind resource study for IJV is unavailable at the time of publishing this report. An annual mean wind speed of 9.9m/s at 100m reference height is specified in RVO's metocean study /2/. The Weibull parameters for the site are extracted by fitting the wind speed probability distribution obtained from the occurrence table of wind speed and direction at IJV published in the metocean study to a Weibull distribution /2/. The variation of wind speed with elevation is calculated using the power law for wind shear. A wind shear exponent (α) of 0.075 is estimated by fitting average wind speeds measured by met masts at different elevations, as given in the metocean study /2/ , to a power law curve (Eqn. 3-1). A turbulence intensity of 14% is assumed based on typical values observed for offshore wind farms.

$$U_h = U_{h,ref}\left(\frac{h}{h_{ref}}\right)^{\alpha} \tag{3-1}$$

It was felt that assuming a single annual mean wind speed with fixed Weibull distribution limits the validity of this analysis. To that effect, another case for an annual mean wind speed of 8.5m/s at 100m reference height was added. The two assumed annual mean wind speeds should cover the range of annual mean wind speeds typical for North Sea sites. Moreover, besides the site-specific Weibull distribution (shape factor = 2.19) two additional Weibull distributions are simulated for each wind speed case with Weibull shape factors of 1.75 and 3.0, respectively. The Weibull scale factor for these additional distributions is estimated using an empirical relation between the Weibull shape factor and annual mean wind speed. The choice of Weibull shape factors covers the entire range of Weibull shape factors typically observed for high wind speed site conditions /4/.

Table 3-1: Site wind conditions

Region	IJmuiden Ver, Netherlands	North Sea site I	North Sea site II	North Sea site III	North Sea site IV	North Sea site V
Air density	1.225 kg/m^3	1.225 kg/m^3	1.225 kg/m^3	1.225 kg/m^3	1.225 kg/m^3	1.225 kg/m^3
Annual mean wind speed	9.9 m/s	9.9 m/s	9.9 m/s	8.5 m/s	8.5 m/s	8.5 m/s
Reference height	100 m	100 m	100 m	100 m	100 m	100 m
Wind shear exponent	0.075	0.075	0.075	0.075	0.075	0.075
Weibull shape factor	2.19	1.75	3.0	2.19	1.75	3.0
Weibull scale factor	11.16	11.12	11.09	9.6	9.54	9.52
Turbulence intensity	14%	14%	14%	14%	14%	14%

Metocean conditions for IJV relevant for monopile design in Turbine.Architect are summarized in Table 3-2. The geological desk study states that the water depth at IJV varies between 16.8m and 46.9m /7/. An average value of 30m is assumed for the Turbine.Architect analysis. Assuming that installation and O&M activity will be based on IJmuiden port, we can roughly estimate a distance of 85 km from the construction port to the centre of the designated area for IJV wind farm development. All other metocean data is derived from the metocean study /2/. The mean sea level (MSL) tidal level, as measured from the lowest astronomical tide (LAT) datum, is assumed to be 0.4 times the highest astronomical tide level. The tidal level at the highest astronomical tide, as measured from the lowest astronomical tide (LAT) datum, is estimated by deducting the storm surge from the highest water level.

Table 3-2: Site metocean conditions

Parameter	Value
Water depth	30m
50-year extreme wave height	14.5m
Current velocity	0.9m/s
Significant wave height	1.44m
Storm surge	2.2m
Mean sea level (MSL) tidal level	0.5m
Tidal level at highest astronomical tide (HAT)	1.2m
Distance to construction port	46mi (approx. 85 km)

The geology of the site is described in the published geological desk study /7/. In general, ground conditions are relatively homogenous across the site although some areas will have quite different soil profiles as is normal for such a large site. The most likely, averaged ground profiles estimated based on the geological description in the desk study are summarized in Table 3-3. For geotechnical parameters not covered in the geological desk study, an educated estimate is made.

Table 3-3: Average soil profile for IJV site

Description	Layer	Epoch	Start	End	Thick-ness	Rel. density	Soil type	Submerged unit weight		Internal angle of friction		Skin friction limit	
			(mbsf)	(mbsf)	(m)			(kN/m^3)		(degrees)		(kPa)	
								Start	End	Start	End	Start	End
Southern Bight Formation – Bligh Bank Member	1	Holocene	0	3	3	Loose	Sand	9	9	34	34	50	50
Naaldwijk Formation	2	Holocene	3	6	3	Loose	Sand	9	9	34	34	60	60
Eem Formation – Brown Bank Member	3	Late Pleistocene	6	9	3	Med. dense	Sand	10	10	38	38	81	81
Eem Formation (Eemian)	4	Late Pleistocene	9	15	6	Dense	Sand-silt	11	11	40	40	96	96
Yarmouth Roads Formation	5	Early to Middle Pleistocene	15	100	85	Very dense	Sand	12	13	42	44	115	150

3.2.2 WTG headline parameters

To capture the WTG LCoE optima in the Turbine.Architect numerical analysis, headline parameters such as power rating and specific power density were varied over a large range of possible values. The specific power density is the ratio of WTG power rating and rotor swept area. For a given WTG power rating, the specific power density determines the rotor diameter.

For the lower bound of the main headline parameters, the current state of art WTG sizes serve as a good indicator. In 2018, GE announced the 12MW Haliade-X with a 220m rotor /8/. In the following years, other WTG manufacturers have followed with the announcement of large offshore machines, for example:

- In February 2021, Vestas announced to start serial production of a 15MW offshore WTG with a 236m rotor diameter /11/.
- In 2021, Siemens Gamesa announced a 14MW direct drive 222m rotor machine /9/.
- In 2021, Mingyang, a Chinese WTG manufacturer, announced a 16MW 242m rotor machine with a hybrid drive system/10/.
- Also in 2021, GE announced an up-rated version of the Haliade-X with a power rating up to 14MW /12/.

In accordance with market trends, WTGs were modelled with ratings starting from 12MW and capped at 30MW. Specific power rating was varied from 300W/m2 to 450W/m2 to account for all possibilities although it has been observed that large offshore WTGs in the market typically lie on the higher end of the power rating spectrum (350 – 450W/m2). These combinations of WTG rating and specific power density lead to rotor diameters varying from 184 meters to a maximum of 357 meters. A tower-monopile interface elevation of 15 meters above sea level is assumed for all cases. The hub height is dependent on the rotor diameter. It is assumed to be the sum of the interface elevation and the blade length plus an additional 10 meters clearance of the blade from the platform at interface elevation.

The design tip speed ratio (TSR) is one of the main design parameters in WTG design and describes the ratio between the tip speed of the blade and incoming wind speed. By redesigning a blade for a higher tip speed ratio, the blade designer can afford a lower solidity rotor. A slender blade may boost aerodynamic efficiency however this doesn't necessarily translate into structural efficiency. A slender blade with thinner sections requires thicker spar caps and trailing edge stiffeners to be sufficiently stiff in both flapwise and edgewise directions.

Another important parameter is the maximum tip speed. A higher allowance for tip speed confers system-level cost benefits by reducing rotor torque. This in turn results in a lighter and cheaper gearbox. As WTGs increase in size, there is likely to be an attempt to increase maximum tip speed in order to keep gearbox sizes in check. Moreover, increasing the rotor speed allows for a higher 1st natural frequency for the support structure design by reducing the possibility of resonant frequency clashes with 3P rotor speed at low wind speeds. This could enable stiffer and lighter tower designs.

To quantify the effects of design TSR and maximum tip speed on cost of energy, it is important to analyse for a reasonable range of design TSR values and maximum tip speeds. Three different design TSRs: 9, 10 and 11; are modelled. With increasing TSR, the corresponding maximum tip speed is proportionally increased to fix the wind speed at which this maximum tip speed is attained. The maximum tip speeds corresponding to the three design TSRs of 9, 10 and 11 are 90 m/s, 100 m/s and 110 m/s respectively.

Finally, two different drivetrain configurations are modelled: a medium speed (two-stage gearbox) geared WTG with Permanent Magnet Generator (PMG), and a direct drive (no gearbox) WTG with Permanent Magnet Generator (PMG). While different manufacturers have historically offered different drivetrain solutions based on legacy and supply chain constraints, the aforementioned drivetrain solutions are likely to be the dominant offerings for large offshore WTGs. The WTG headline parameters to be modelled in this analysis are summarized in Table 3-4.

Table 3-4: WTG headline parameters

Parameter	Range/Value	Step size
Specific power density	300 – 450 W/m2	50 W/m2
WTG rating	12 – 30 MW	1 MW
Drivetrain	Medium speed geared with PMG, Direct drive with PMG	-
Tip speed ratio	9.0 – 11.0	1.0
Lifetime	25 years	-
Pitch control method	1P Individual pitch control	-

3.2.3 Financial inputs

The analysis also studies the sensitivity of the cost of energy to the discount rate. The discount rate is the rate of return used to discount future cash flows back to their present value. For this purpose, three different discount rates are modelled: 4%, 6% and 8%.

3.2.4 WTG and farm modelling assumptions

Besides defining headline input parameters for the analysis, modelling in Turbine.Architect also involves several implicit assumptions at both WTG and farm levels. The main assumptions made for WTG design in Turbine.Architect can be summarized as follows:

- The blade spar caps utilize uniaxial carbon fibre material in place of uniaxial glass fibres. Irrespective of length, blades are manufactured in single monolithic pieces thus not accounting for any spanwise segmentation for long blades.
- A geared drivetrain comprises a two-stage gearbox with a PMG generator. A direct-drive type WTG assumes a permanent magnet generator (PMG) with no gearbox.
- Geared configuration consists of two main bearings and a low-speed shaft. The shaft is designed to be a solid forged shaft. However, for large WTGs (when solid forged shaft mass exceeds 25 tonnes) hollow cast shafts are used instead. A correction

factor is applied to the mass of the designed solid forged shaft to estimate the mass of the hollow cast shaft. The correction factor is based on DNV's experience in designing main shafts.

- A tower is typically comprised of sections. Tower section design is constrained by limits to maximum transportable length and maximum transportable mass of a section which are set at 45 meters and 400 metric tonnes, respectively for this study.
- WTG costs are inclusive of manufacturing, material and labour costs, transportation to port and WTG manufacturer profit margin.
- Material, labour, equipment, and component unit costs are based on rates observed by DNV for projects in Northwest Europe. These rates are based on years of DNV project experience in wind power projects.
- The WTG is assumed to be mounted on a monopile type offshore support structure.

At the wind farm level, the Turbine.Architect models used in this study make implicit assumptions related to the electrical infrastructure, transportation, installation, and financial modelling. These can be summarized as follows:

- For purposes of farm energy yield calculation and in-field cable costing, the WTGs in a wind farm are assumed to be uniformly spaced. The intra and inter-row WTG spacing is assumed to be six times the rotor diameter and therefore is different for different WTG models. Note that the WTG layout is not optimized in this study.
- While fixing the layout, the model determines the number of WTGs in a single row by picking the lowest value from the number of WTGs allowed in a string (6) or the maximum power rating allowed in a single string (94MW).
- The electrical infrastructure costing accounts only for in-field collection cables. It was agreed with the client to not model the offshore farm substation(s), reactive compensation hardware, HVDC converter(s) and high voltage export cables up to grid connection point. The in-field cable voltage is assumed to be 66 kV.
- Offshore O&M costs are calculated using DNV’s internal O&M modelling tool, O2M. This O&M model also outputs average WTG availability.
- For energy yield modelling, standard loss factors are assumed. Wake losses are estimated from a wake loss database for different WTG layout configurations. WTG availability is derived from the O&M model. Blockage and sub-optimal performance losses are assumed to be 2% and 0.5% respectively. Curtailment losses are set to 0. Moreover, the farm energy yield calculation assumes identical topography and wind speed conditions for all WTG locations. Variation in energy yield due to annual variability in site wind conditions is not accounted for. Please note that energy yield values calculated here should only be used for purposes of comparing the performance of different WTGs across a large range of scenarios. For more reliable, accurate energy yield values a more detailed energy assessment using DNV’s WindFarmer software is advisable.
- The offshore installation model calculates the cost of transporting the WTGs and foundations from construction port to site and then installing them. It does not include the cost of transportation to the port. This is included in the WTG cost markup factors.

- Project development costs include package management (pre-tendering work), legal, construction insurance, contingency and survey costs. The contingency costs are assumed to be 5% of farm CapEx for this analysis. The package management, legal and construction insurance are similarly assumed to be 5%, 1% and 1% of the total farm CapEx, respectively. A fixed survey cost is assumed based on observed values on wind farm projects of similar size.
- Land lease costs are not considered in this analysis.
- LCoE cost calculations are based on a farm operational lifetime of 25 years and an additional 1 year assumed for decommissioning.

3.2.5 O&M modelling assumptions

Considering the assumptions above of 46 nautical miles (85km) to Ijmuiden Port and typical site conditions of 1.44 m long term mean significant wave height, DNV has deployed its in-house tool, O2M to assess the potential availability and operational expenditure implications of varying the WTG size and hence having a different number of WTGs to achieve a fixed installed capacity of approximately 1000 MW. For this purpose, DNV considered a modelling envelope of 10, 12, 15, 18, 20 and 24MW WTG sizes. For each of these potential WTG models, DNV estimated the expected WTG availability as well as the logistical requirements and operational expenditure for two main access strategies:

1. An onshore based strategy deploying Surface Effect Ship (SES) vessels (as currently used in Borssele I & II)
2. An offshore strategy deploying a Service Operations Vessel (SOV) is also used for other projects such as Gemini.

This examination allows the assessment of cost reductions expected as WTGs increase in size and there is possibly a reduction in the number of site visits and hence resources required. For this assessment DNV has considered the following generic assumptions:

- SES vessel day rate of 4,700 Euros per day and SOV day rate of 23,400 Euros per day plus catering costs of 70 Euros per person per day.
- Average expected number of full-time employed (FTEs) technicians of 0.4 technicians per WTG (in line with industry observed values) with an expected 50% of FTEs per shift.
- Variation of jack-up vessel day rate according to WTG size requirements as larger WTGs require larger and more capable vessels.
- Average main component replacements per WTG per year of 0.05 for all scenarios, so a generic assumption that all WTG models are equally reliable. Whilst newer and larger WTGs are expected to be more reliable than previous models, this is not always the case and therefore, DNV has considered a conservative but reasonable approach, to expect at least the same level of failure rates in all WTGs assessed.
- Average main component replacement campaign of 7 days including waiting on weather and mobilisation and demobilisation time.

- Insurance cost of 7000 Euros/MW per year.
- Generic allowance of 20 FTEs for management roles for all scenarios.
- Revenue and losses are estimated at an average energy price of 50 Euros/MWh.
- Average cost of 21,000 Euros/WTG per year for the balance of plant O&M to take into account the cost of foundations and array cable inspections and maintenance.
- Average cost per spare part and consumables required is as shown below in Table 3-5. Major components are all components that require a jack-up vessel such as gearbox, generator, blades, blade bearing, transformer, etc. Subcomponents are large units like the converter that do not require a jack-up vessel but are costly and require a reasonable amount of time to replace. Minor components are small components or fast repairs like a hydraulic hose, replacing a sensor, replacing a small fan, etc.
- Profit and risk margin of 10% on top of offshore logistics, parts and consumables, technicians and onshore staff rates for all scenarios.
- No future cost efficiencies are implemented in the O&M analysis as these are to affect the different scenarios in a similar way, therefore, the inclusion of this factor would not have an impact on the comparison of expected costs.

It is important to note that there is high uncertainty on these costs and DNV has seen a significant variation in the cost of main components for the larger WTGs in the range of 6-15 MW. This is due to the different commercial implications of each contract and project and therefore, these costs can see significant variations of even +70% differences compared to our generic estimations. However, due to the low frequency of main component replacements, the impact of a 100% variation is significantly low (<10%) in total operational expenditure.

Table 3-5: Component cost assumptions for O&M modelling.

WTG capacity (MW)	Servicing consumables per WTG per year	Minor parts	Subcomponent	Major component
10.0	EUR 8,000	EUR 2,300	EUR 45,800	EUR 896,200
12.0	EUR 8,200	EUR 2,400	EUR 50,400	EUR 957,100
15.0	EUR 8,800	EUR 2,600	EUR 61,000	EUR 1,141,300
18.0	EUR 9,400	EUR 2,800	EUR 67,100	EUR 1,325,300
20.0	EUR 9,900	EUR 2,900	EUR 73,800	EUR 1,462,500
24.0	EUR 10,500	EUR 3,000	EUR 81,200	EUR 1,693,200

3.2.6 Future cost learning rates

Experience shows that the costs of any technology tend to decline with time and that can be explained by a single factor: the Cost Learning Rate (CLR). CLR establishes a constant relationship between the doubling of accumulated unit production numbers and the cost decline.

$$\text{Cost index}(t) = \left(\frac{\text{Cumulative capacity additions } (t)}{\text{Reference cumulative capacity additions}}\right)^{\log_2(1-\text{Learning rate})}$$
$$\text{Cost}(t, r) = \text{Cost index}(t) \times \text{Cost at reference year}(r)$$

(.3-2)

The logic behind the CLR is that a host of factors improve with experience. These factors can be summarized as follows:

- First, R&D becomes less important as the product matures and is fine-tuned.
- Economies of scale then increase, both at individual manufacturing facilities and also through improving supply chains.
- Moreover, skill sets at all levels improve with experience – in government, management, and labour – and also as schools and universities transmit better practices to new generations of workers.

Although technology costs tend to fall at constant rates relative to deployment, other costs – notably labour – do not. Thus, the O&M cost curves for wind are around half, at best, of the technology learning rate, with installation costs falling at a lower rate still in relation to market growth.
Pressure on the availability of land for development onshore as well as the search for stronger and more stable wind conditions means that the renewables industry is increasingly leaning towards the offshore wind to deliver large volumes of green electricity close to where people want to live. As a result, DNV's Energy Transition Outlook (ETO) 2021 /13/ predicts global offshore wind capacity growth will continue over the coming three decades, totalling 2068 GW by the end-2050. Highlighting the dominance of China and Europe, the two regions will make up 58% of global installed offshore capacity by 2050 /13/. This reflects China's aim to locate renewables capacity near coastal electricity consumption hubs, and the European push for offshore wind amid weakening growth for onshore renewables in the region. OECD (Organisation for Economic Co-operation and Development) countries in Pacific Asia will also be a key hotspot for growth – notably through South Korea and Japan /13/. In North America, growth in the United States will accelerate after a slow start in the market, driven by increasingly ambitious renewable energy portfolio standards in eastern States /13/. Global offshore wind capacity growth is expected to surge over the coming decades, with net capacity growth between 2021-2030 totalling 195GW, and accelerating further to an equivalent 551GW growth between 2031-2040 and 1023GW between 2041-2050 /13/. These predictions of capacity additions are used to estimate CLRs for this study shown in Table 3-6. The CLR used in this study are based on internal discussions between DNV domain experts. The CLR for the array cable supply cost is taken from a previous DNV internal study on HVDC and HVAC transmission systems.

In the case of Rotor Nacelle Assembly (RNA) and tower/bottom-fixed foundations, the learning factors can be divided into two parts. Explicit CLRs, as shown in Table 3-6, capture learnings accrued as a result of economies of scale, advancements in manufacturing and assembly processes, design improvements (yet unknown break-through concepts, innovative materials, less conservative component design standards) and OEM profit margin reduction (due to auctioning of wind power projects). Besides the explicit CLRs, DNV has also assessed how WTG design loads are likely to evolve over time, as shown in

Table 3-7. Fatigue loads will reduce due to refined methods of accounting for turbulence and advanced control features (LIDAR assisted control, adaptive control strategies, etc.). Similarly, an extreme loads reduction is likely to accrue from less conservative standards with respect to the accounting of deterministic gusts. The resulting savings in component mass and cost are captured in the Turbine.Architect turbine design and we accordingly name this the implicit CLR.

Figure 3-3: Technology learning curve.

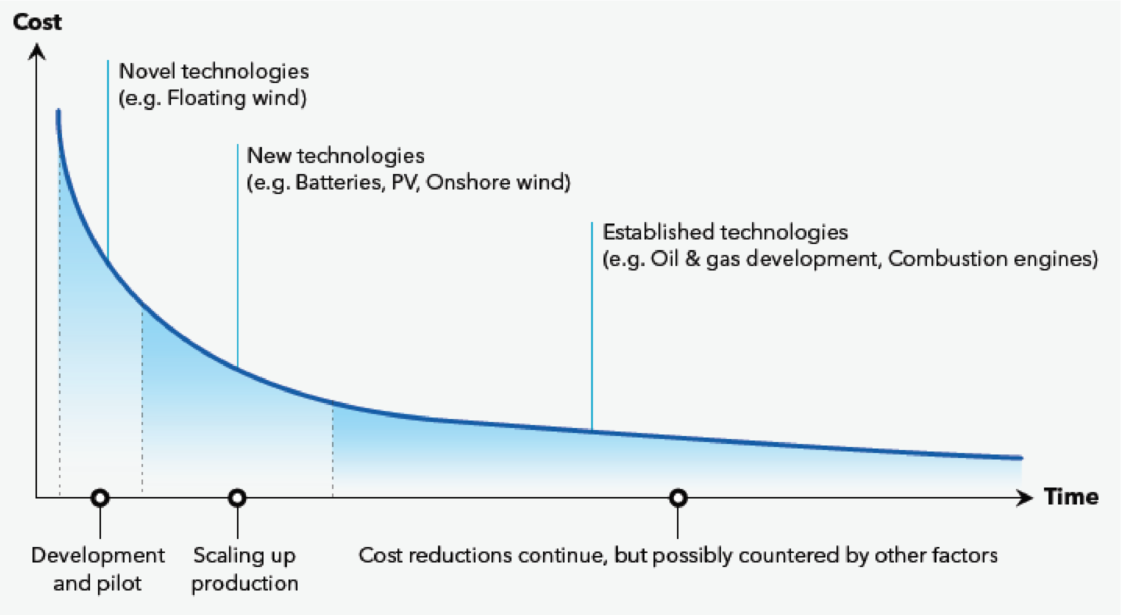


Table 3-6: CLR assumptions based on DNV expert opinion.

Bottom fixed (project specific categories)	2020	2030	2040
Project management & development expenditures	100 %	100 %	100 %
Rotor Nacelle Assembly (RNA) supply cost	100 %	86 %	73 %
Tower & bottom fixed foundation supply cost	100 %	100 %	100 %
Array cable supply cost	100 %	94 %	88 %
WTG installation cost	100 %	95 %	90 %
Bottom fixed foundation installation cost	100 %	95 %	90 %
OPEX	100 %	96 %	92 %

Table 3-7: Load reduction factors based on DNV expert opinion.

Load reduction factors	2020	2030	2040
WTG Extreme loads	1.0	0.9	0.85
WTG Fatigue loads	1.0	0.83	0.8

3.3 Operations and Maintenance (O&M) cost assessment

Based on assumptions made in Section 3.2.5, DNV has estimated the following costs and WTG availability for the SES (Table 3-8) and the SOV strategies (Table 3-9). Note that these costs are calculated for the 2020 scenario, thus no CLRs are applicable to these values.

Table 3-8: OpEx cost estimate for SES strategy

Access Strategy:	SES, Hs 2.00 m (safe transfer limit)					
Distance to O&M port (nm)	46	46	46	46	46	46
Average Hs long term	1.48	1.48	1.48	1.48	1.48	1.48
Number of WTGs	100	84	67	56	50	42
WTG capacity	10	12	15	18	20	24
Project capacity (MW)	1000	1008	1005	1008	1000	1008
Full Time Equivalent Technicians:	40	34	27	23	20	17
Technicians per shift:	20	17	14	12	10	9
Number of CTVs:	2	2	2	1	1	1
Average main component replacements per year:	5.0	4.2	3.4	2.8	2.5	2.1
Profit and risk margin assumption	10%	10%	10%	10%	10%	10%
Jack-Up (JU) Day rate (kEUR/day)	60,000	65,000	90,000	200,000	215,000	250,000
Annual average costs (mEUR per year)						
Crew transfer vessels	3.6	3.6	3.6	1.8	1.8	1.8
Helicopter	-	-	-	-	-	-
SOV	-	-	-	-	-	-
JU costs per year	2.5	2.2	2.5	4.6	4.4	4.3
Technicians (full-time)	5.9	5.0	3.9	3.4	2.9	2.5
Parts and consumables	8.1	7.3	6.8	6.5	6.3	6.0
Overhauls	-	-	-	-	-	-
Service base	2.8	2.8	2.8	2.8	2.8	2.8
Onshore Staff Costs	3.0	3.0	3.0	3.0	3.0	3.0
BoP Unscheduled Maintenance	0.9	0.8	0.6	0.5	0.5	0.4
BoP Scheduled Maintenance	1.2	1.0	0.8	0.7	0.6	0.5
Insurance	7.0	7.0	7.0	7.0	7.0	7.0
Operator Profit and Risk Margin	2.3	2.1	2.0	1.9	1.8	1.8
Miscellaneous	0.2	0.2	0.1	0.1	0.1	0.1
Blade maintenance	0.4	0.4	0.3	0.2	0.2	0.2
Structural condition monitoring	0.1	0.1	0.1	0.1	0.1	0.1
Average Annual Direct Costs:	**38.0**	**35.5**	**33.7**	**32.6**	**31.6**	**30.4**
Cost per WTG [kEUR per WTG]:	**380**	**422**	**502**	**583**	**632**	**724**

Cost per MW [kEUR per MW]:	**38.0**	**35.2**	**33.5**	**32.4**	**31.6**	**30.2**
Cost per MWh [EUR per MWh]:	**9.0**	**8.3**	**7.9**	**7.6**	**7.5**	**7.1**
MW Scenarios:	10	12	15	18	20	24
Cost reduction EUR per MW		1,275,598	607,994	343,864	503,876	298,011
Average cost reduction EUR/MW:	605,869					
Cost reduction EUR/MW from 10 to 24 MW:	543,326					

From these results, it is observed that an average cost reduction is to be expected of approximately 0.5 million Euros per MW with variations ranging from 0.3 - 1.3 million Euros per MW increase depending on the scenario. The main cost reductions are due to parts and consumables, technicians, the balance of plant O&M and to a lesser extent due to blade maintenance requirements.

A logistical cost which has an increasing trend is jack-up vessel costs. As WTGs increase in capacity, the vessels needed to perform the main component replacements require enhanced capabilities and hence are more expensive. A notable step-up in cost occurs for WTGs above 15MW where the expected day rate of the vessel increases from 90,000 Euros per day for a 15MW suitable vessel to €200,00 per day for an 18MW suitable vessel.

It is interesting to note that the trend is that, as WTG size increases, the reduction in cost decreases per MW and per MWh. It is therefore expected that cost reductions will reach a plateau at a certain level. Furthermore, if the decision is to stay at a certain MW capacity and develop the supply chain for this specific model and capacity, further standardisation benefits could be achieved. This is due to technology developments, supply chain development, learning curves, synergies of portfolio stocking and parts management as well as mobilisation and demobilisation of teams to perform specific activities such as blade repairs for various projects with the same WTG technology.

Table 3-9 OpEx cost estimate for SOV strategy

Access Strategy:	SOV + 1 CTV, Hs 1.5m (safe transfer limit)					
Distance to O&M port (nm)	46	46	46	46	46	46
Average Hs long term	1.48	1.48	1.48	1.48	1.48	1.48
Number of WTGs	100	84	67	56	50	42
WTG capacity	10	12	15	18	20	24
Project capacity (MW)	1000	1008	1005	1008	1000	1008
Full Time Equivalent Technicians:	40	34	27	23	20	17
Technicians per shift:	20	17	14	12	10	9
Number of CTVs:	1	1	1	1	1	1
Average main component replacements per year:	5.0	4.2	3.4	2.8	2.5	2.1
Profit and risk margin assumption	10%	10%	10%	10%	10%	10%
JU Day rate (kEUR/day)	60,000	65,000	90,000	200,000	215,000	250,000
Annual average costs (mEUR per year)						
Crew transfer vessels	1.8	1.8	1.8	1.8	1.8	1.8
Helicopter	-	-	-	-	-	-
SOV	10.0	9.9	9.8	9.7	9.7	9.6
JU costs per year	2.5	2.2	2.5	4.6	4.4	4.3
Technicians (full-time)	5.9	5.0	3.9	3.4	2.9	2.5
Parts and consumables	8.1	7.3	6.8	6.5	6.3	6.0
Overhauls	-	-	-	-	-	-
Service base	2.8	2.8	2.8	2.8	2.8	2.8
Onshore Staff Costs	3.0	3.0	3.0	3.0	3.0	3.0
BoP Unscheduled Maintenance	0.9	0.8	0.6	0.5	0.5	0.4
BoP Scheduled Maintenance	1.2	1.0	0.8	0.7	0.6	0.5
Insurance	7.0	7.0	7.0	7.0	7.0	7.0
Operator Profit and Risk Margin	3.1	2.9	2.8	2.9	2.8	2.7
Miscellaneous	0.2	0.2	0.1	0.1	0.1	0.1
Blade maintenance	0.4	0.4	0.3	0.2	0.2	0.2
Structural condition monitoring	0.1	0.1	0.1	0.1	0.1	0.1
Average Annual Direct Costs:	**47.0**	**44.4**	**42.5**	**43.3**	**42.3**	**41.0**
Cost per WTG [kEUR per WTG]:	**470**	**528**	**634**	**774**	**845**	**977**
Cost per MW [kEUR per MW]:	**47.0**	**44.0**	**42.2**	**43.0**	**42.3**	**40.7**

Cost per MWh [EUR per MWh]:	11.1	10.4	10.0	10.2	10.0	9.6
MW Scenarios:	10	12	15	18	20	24
Cost reduction EUR per MW		1,322,103	638,998	-250,533	534,880	305,762
Average cost reduction EUR/MW:	700,436					
Cost reduction EUR/MW from 10 to 24 MW:	426,760					

From these results, it is observed that for an SOV strategy, an average cost reduction is to be expected of approximately 0.4 million Euros per MW with variations ranging from 0.3 -1.3 million Euros per MW increase depending on the scenarios. The main cost reductions are mainly due to cost reductions in parts and consumables, technicians, the balance of plant O&M and a lower magnitude of the blade maintenance requirements.

Similar to the SES vessel strategy, a logistic cost which doesn't show this decreasing trend is the jack-up vessel costs, which increase with increasing WTG capacity. As WTGs increase in capacity, the vessels required to perform the main component replacements require enhanced capabilities and hence are more expensive. A significant expected step-up in cost is for WTGs above 15 MW where the expected day rate of the vessel increases from 90,000 Euros per day for a 15MW suitable vessel to €200,00 per day for an 18MW suitable vessel.

It is interesting to note the trend that as WTGs increase in capacity, the cost reduction, decreases per MW and per MWh. Therefore, it is expected that cost reductions are to reach a plateau at a certain level. Furthermore, it is noted that if the decision is to stay at a certain MW capacity and develop the supply chain for this specific model and capacity, further standardisation benefits could be introduced. This was due to technology developments, supply chain development, learning curves, synergies of portfolio stocking and parts management as well as mobilisation and demobilisation of teams to perform certain specific activities such as blade repairs for various projects with the same WTG technology.

In conclusion, it is seen that the SES strategy is the most cost-optimal strategy for O&M of a large scale wind farm as assumed in the current analysis.

3.4 Optimal WTG size analysis results

The results of the Turbine.Architect numerical cost study are presented in this section. Firstly, the general cost trends with respect to WTG rating are described. For this purpose, a baseline case representing a WTG with geared drivetrain configuration, design tip speed ratio of 10 and maximum tip speed of 100 m/s is shown. The WTG is designed for loads corresponding to an annual mean wind speed of 9.9 m/s. The plots shown are cost estimates for 2040 generated after applying learning rates to present-day WTG price estimates.

This is followed by studying the sensitivity of the cost of energy to different site conditions, WTG design configurations, financial parameters and OpEx assumptions.

3.4.1 General cost trends

The WTG cost per MW is shown to increase with WTG rating. This can be explained by cost trends for the nacelle and rotor; and how WTG rating scales with rotor diameter. Cost of power rating driven nacelle components such as the generator, power converter and transformer scale almost linearly with WTG rating. Now for a fixed specific power density, the WTG rating scales quadratically with rotor diameter. Thus, the cost of power rating driven nacelle components also scale quadratically with WTG rating. In theory, WTG bending loads increase cubically with rotor diameter. Thus, the cost of structural components in the rotor and nacelle scale cubically with rotor diameter. Combining these separate trends with respect to rotor diameter, we find that WTG cost scales faster than quadratic while the WTG rating scales quadratically with rotor diameter. This explains why in theory WTG cost on a per MW basis should increase. It is also evident from Figure 3-4 that for a given WTG rating, the WTG cost per MW decreases with increasing specific power density. As the rotor diameter decreases, the WTG loads decrease, and the structural components become lighter and less expensive.

The total WTGs CapEx sums up the WTG supply cost of all WTGs in a wind farm to achieve a 1000 MW rated capacity. From Figure 3-4, it is clear that the cost of a single WTG increases with increased nameplate capacity. On the other hand, as nameplate capacity increases the number of WTGs required to be installed decreases. Combining these two factors we find that the WTGs CapEx still increases with WTG rating. This is shown in Figure 3-5. Note that the WTG cost is inclusive of rotor-nacelle assembly and tower but exclusive of offshore support structure cost.

The offshore foundation design is determined by a combination of wind loading and hydrodynamic loading. Being a structural component, it is to be expected that foundation cost increases with increased WTG loading. Similar to a WTG, the cost of a monopile will increase with increasing WTG rating. Now, the number of installed foundations in the wind farm decreases with an increased WTG rating. Despite this, Figure 3-6 shows that total foundation CapEx still increases with WTG rating for a 1000MW wind farm.

Figure 3-4: Estimated WTG supply cost on a per MW basis (in million EUR/MW) shown for a geared WTG designed for annual mean wind speed of 9.9 m/s and tip speed ratio of 10. WTG supply cost per MW is shown to increase with increasing WTG rating and decreasing specific power density.

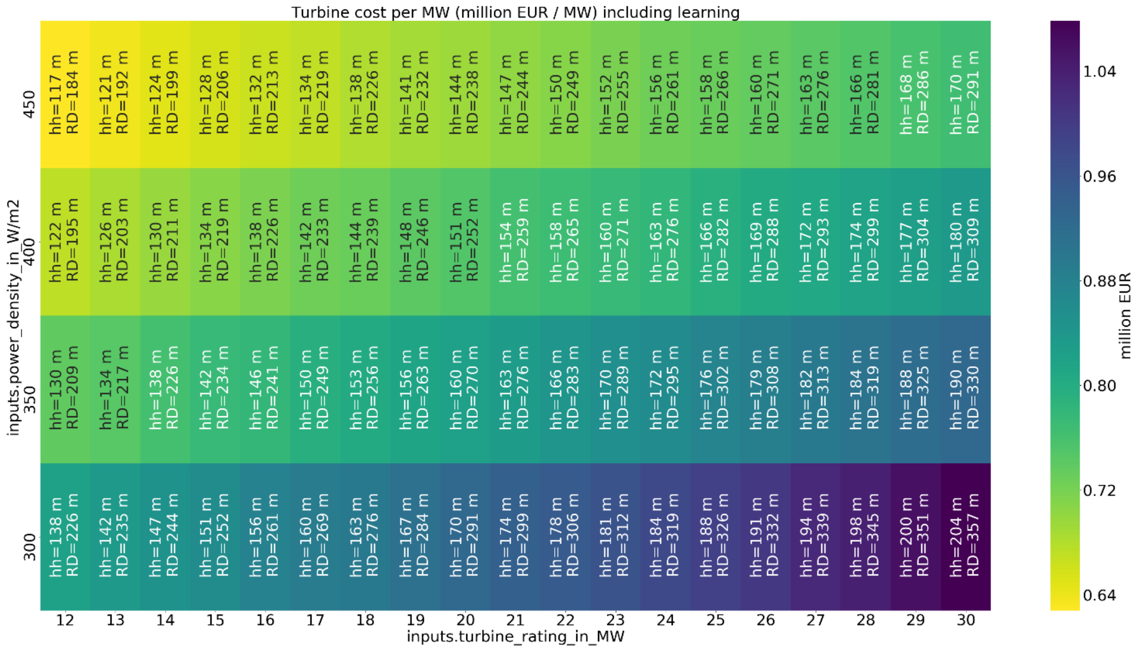


Figure 3-5: Estimated total WTG CapEx (in million EUR) shown for a 1000 MW wind farm project, using a geared WTG designed for annual mean wind speed of 9.9 m/s and tip speed ratio of 10. Total WTG CapEx is shown to increase with increasing WTG rating and decreasing specific power density.

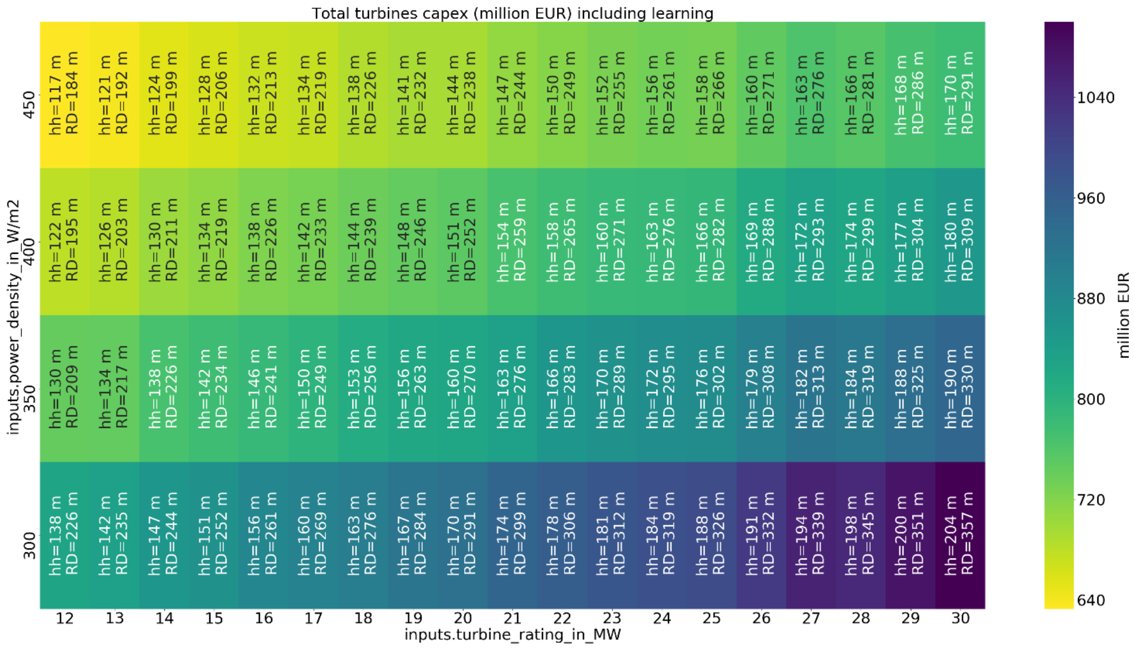
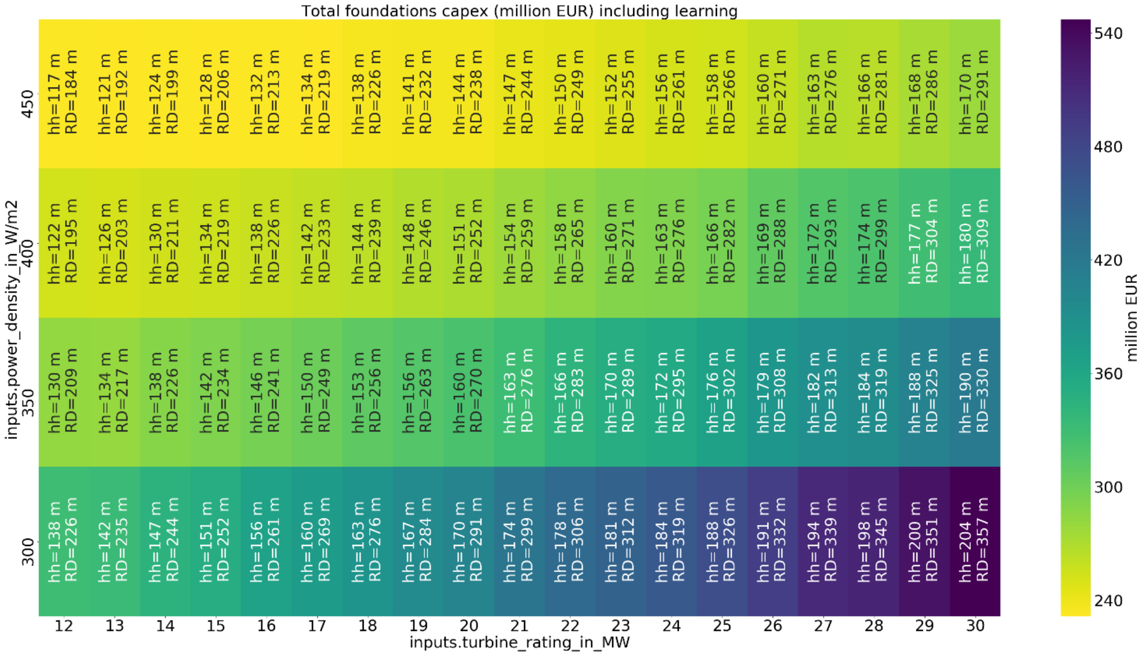


Figure 3-6: Estimated total foundation CapEx (in million EUR) shown for a 1000 MW wind farm project, using a geared WTG designed for annual mean wind speed of 9.9 m/s and tip speed ratio of 10. Total foundations CapEx is shown to increase with increasing WTG rating and decreasing specific power density.



The electrical CapEx estimated for this analysis only accounts for the cost of electrical array cables. Substations and export cables are not modelled. Moreover, the WTGs are arranged in a rectangular grid with equal intra-row and inter-row spacing. This is a simplification which is not necessarily reflective of an actual wind farm layout design. The cost of array cables is dependent on the total length of cables and the type of cable, that is, its current rating. The total length of cables required is in turn dependent on the number of WTGs and the assumed WTG spacing. It is assumed in this analysis that WTG spacing scales with rotor diameter. It is found that the required cable length decreases with WTG rating. This is because while WTG spacing increases the number of WTGs still decreases. The cable cost and thus the electrical infrastructure CapEx shows a general decreasing trend with WTG rating. Moreover, increasing specific power density also decreases the electrical CapEx. This follows because the WTG spacing, which scales with rotor diameter, decreases and so does the required length of infield electrical cables.

The farm installation CapEx, shown in Figure 3-8, is the sum of WTGs and foundations installation costs. It is dependent on the size of WTGs. Larger and heavier WTGs require more expensive jack-up vessels with larger loading capacity for installation. Installation cost per WTG is seen to increase with increasing WTG rating and decreasing specific power density (see Figure 3-9). The installation cost per WTG increases in a stepwise manner rather than continuously. This is because the day rates and commission/decommissioning rates of jack-up vessels also increase in steps. Consider the case of 16 and 17MW WTGs at a specific power density of 300 W/m2 shown in Figure 3-9. A larger jack-up installation vessel is required as we move from a rating of 16 MW to 17 MW and hence the observed jump in total installation cost. However, selecting larger rated WTGs does mean fewer number of WTGs are required to achieve a given wind farm rating. Hence, the total installation cost is a trade-off between the installation cost per WTG and the number of WTGs in a wind farm. Overall, large specific power density WTGs at the lower end of the rating spectrum have the lowest installation cost. Note that within the overall CapEx, installation CapEx is a rather small proportion. For reference, the total WTGs CapEx is approximately 20 times larger than the installation CapEx.

Figure 3-7: Estimated total electrical CapEx (in million EUR) shown for a 1000 MW wind farm project. Total electrical CapEx generally decreases with increasing WTG rating.

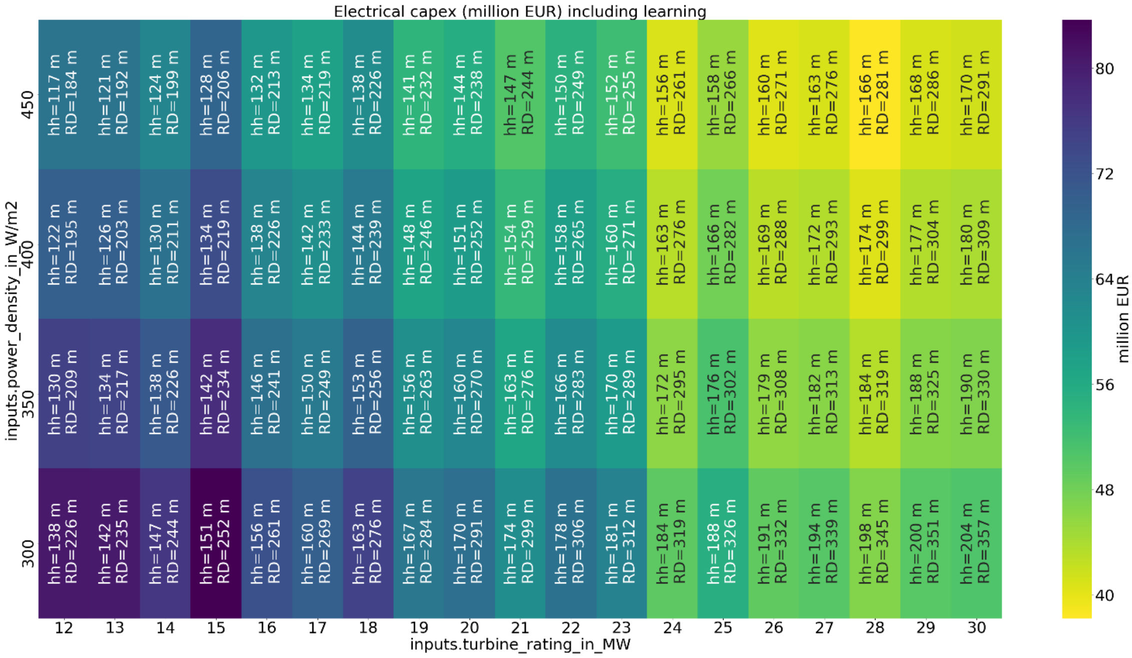


Figure 3-8: Estimated total installation CapEx (in million EUR) shown for a 1000 MW wind farm project. There is no clear trend for installation CapEx with WTG rating.

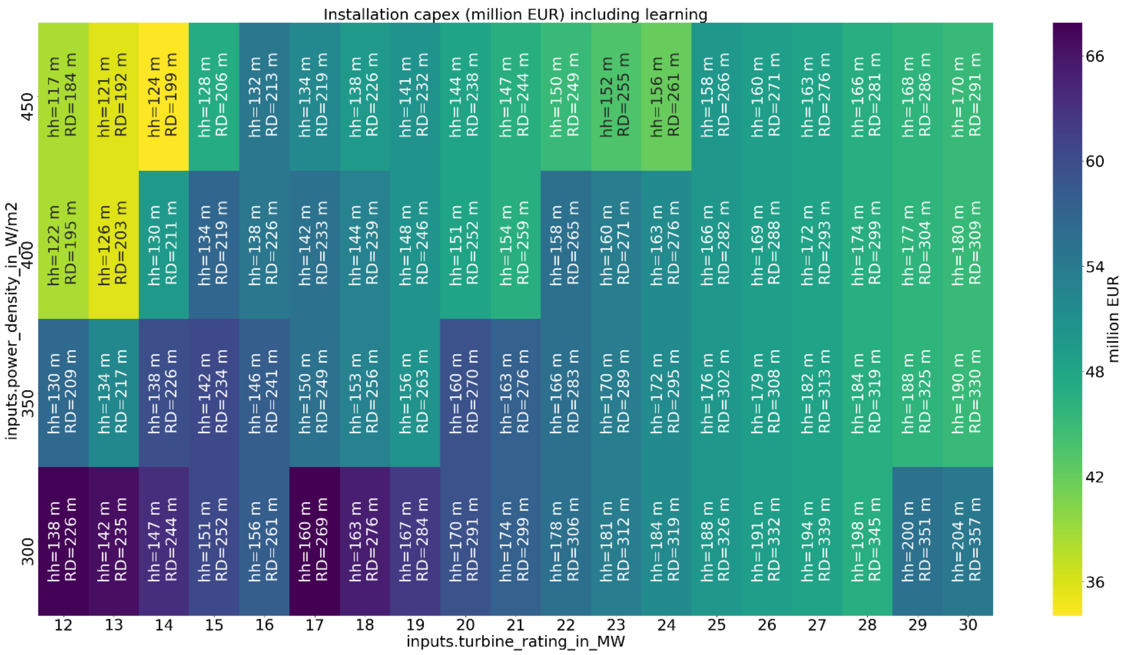
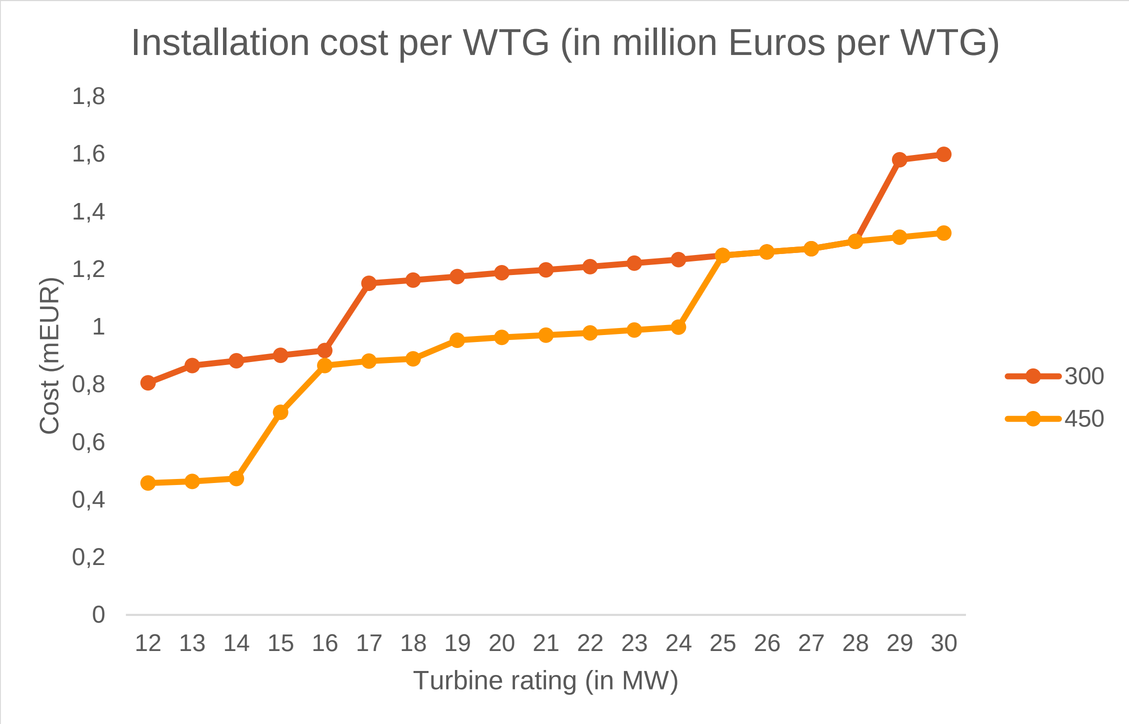


Figure 3-9: Estimated installation cost per WTG (in million EUR) for a 1000 MW wind farm project shown for two different specific power densities (300 & 450 W/m2). Installation cost per WTG is shown to increase with increasing WTG rating.



Another significant component of total CapEx is the project planning and development CapEx. This comprises the package management, construction insurance, legal, survey and contingency costs. The survey cost is assumed to be fixed for all cases. The contingency, package management, construction insurance and legal costs are taken to be 5%, 5%, 1% and 1% of the farm CapEx (sum of the total WTGs, total foundations, electrical infrastructure and installation CapEx), respectively. The project planning and development CapEx, shown in Figure 3-10, increases with increasing WTG rating while decreasing with increasing specific power density. This follows from the total WTGs and foundations CapEx which show a similar trend, and are also the most significant contributors to farm CapEx.

The annual mean farm OpEx, shown in Figure 3-11, follows from the SES OpEx cost modelling in Table 3-8. For values between 12 and 24MW that were not calculated in Table 3-8, an interpolation was used to estimate the OpEx value. For WTG ratings beyond 24MW, an extrapolation trendline was generated to estimate OpEx values. The OpEx is assumed to be independent of specific power rating and hence rotor diameter but varies with WTG rating. The OpEx per WTG increases with WTG rating as given in Table 3-8. However, the annual mean OpEx for the wind farm still decreases with WTG rating because of the reduced number of WTGs. It is seen that in going from a 12MW to a 30MW WTG the annual mean OpEx for the wind farm reduces by about 20%.
In conclusion, it is seen that total farm CapEx increases with turbine rating and reduces with specific power density. This is driven mainly by the turbines and foundations CapEx. The project planning and development CapEx, which is a good proxy for the total farm CapEx (since it is taken to be a small proportion of the total farm CapEx), clearly

illustrates this. On the contrary, the annual mean farm OpEx decreases with turbine rating.

Figure 3-10: Estimated project planning and development CapEx (in million EUR) shown for a 1000 MW wind farm project. Project planning and development CapEx is shown to increase with increasing WTG rating and decreasing specific power density.

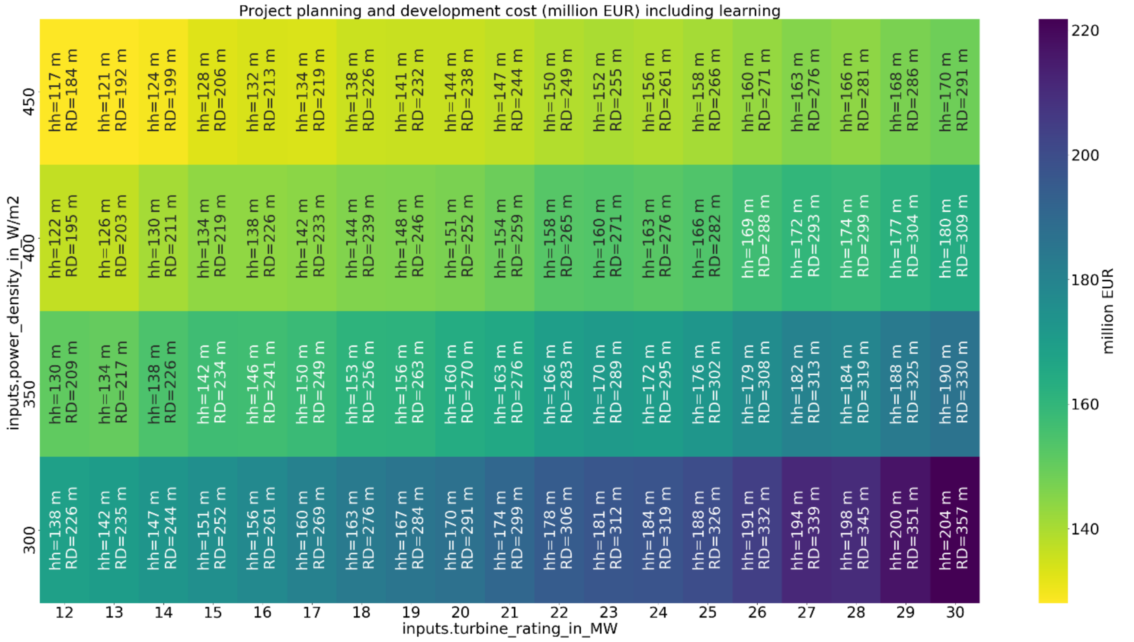


Figure 3-11: Estimated annual mean farm OpEx (in million EUR) shown for a 1000 MW wind farm project. OpEx is shown to consistently decrease with increasing WTG rating.

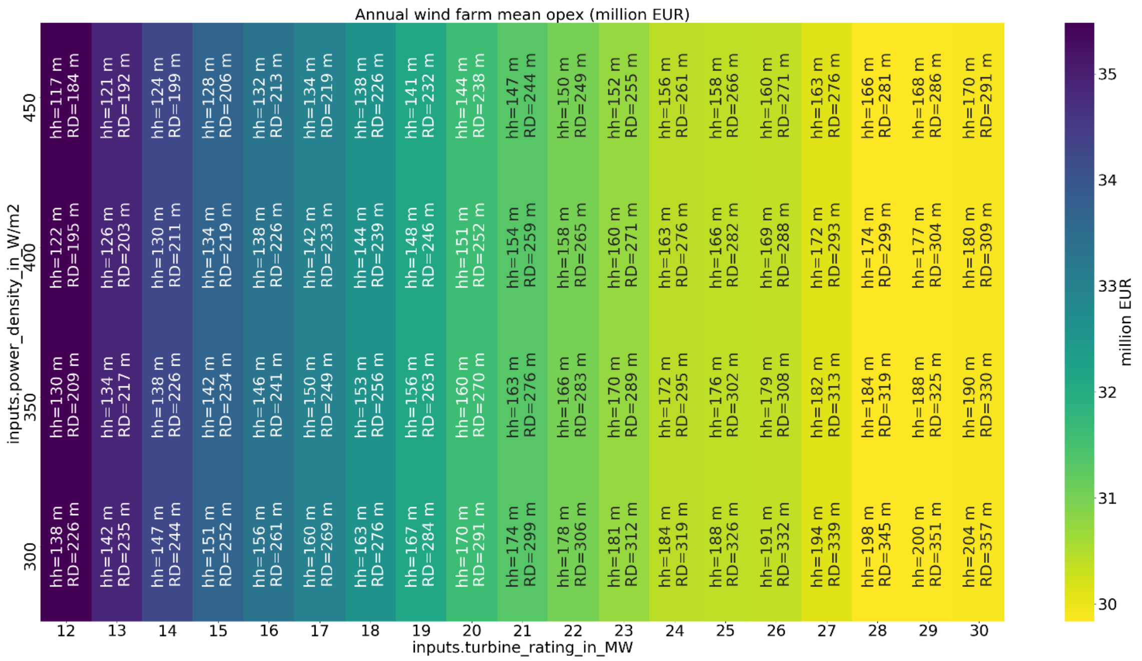


Figure 3-12: Estimated single WTG energy yield (MWhr) shown for a geared turbine designed for annual mean wind speed of 9.9 m/s and tip speed ratio of 10. Single WTG energy yield is shown to increase with WTG rating. Also for a given WTG rating, smaller specific power densities produce more energy.

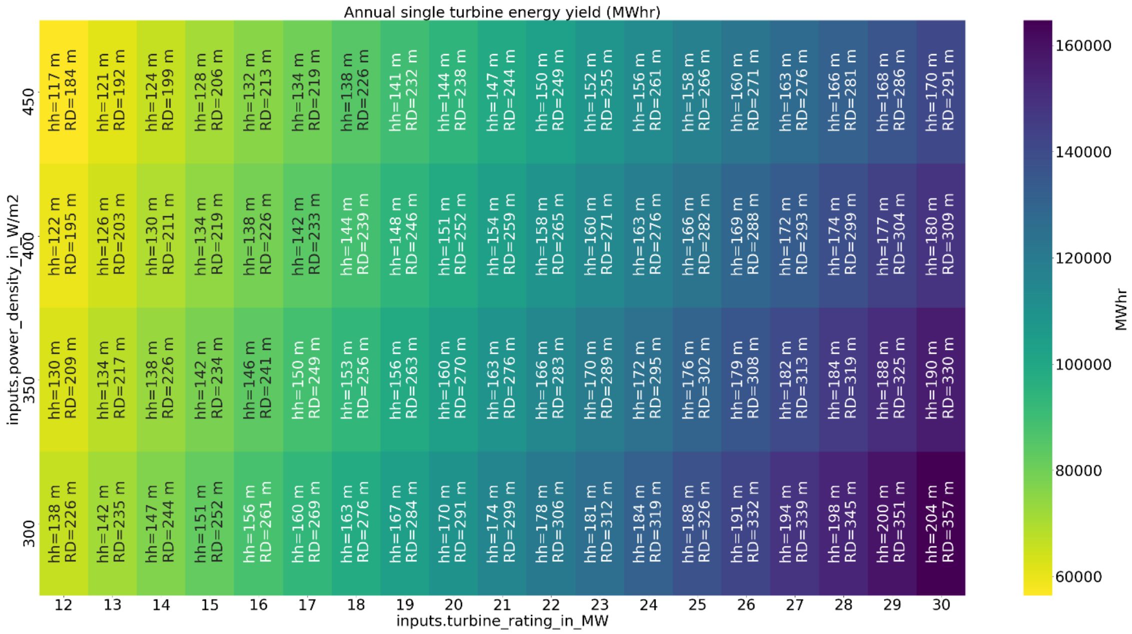
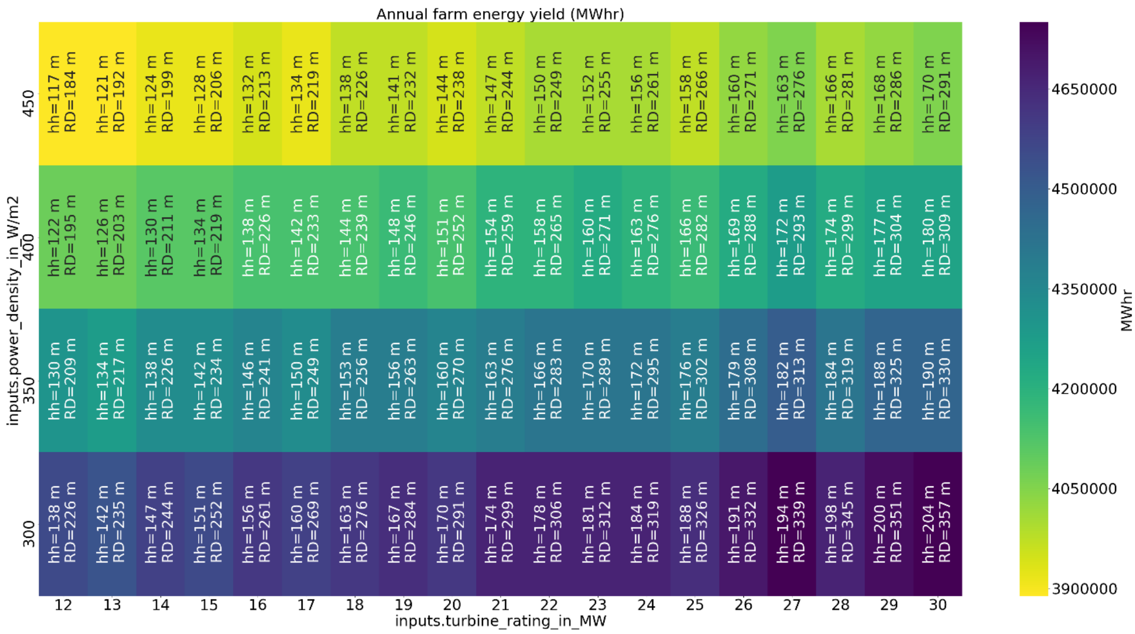


Figure 3-13: Estimated annual farm energy yield (in MWhr) shown for a 1000 MW wind farm project. Annual farm energy yield increases slightly with WTG rating. It also increases with decreasing specific power density.

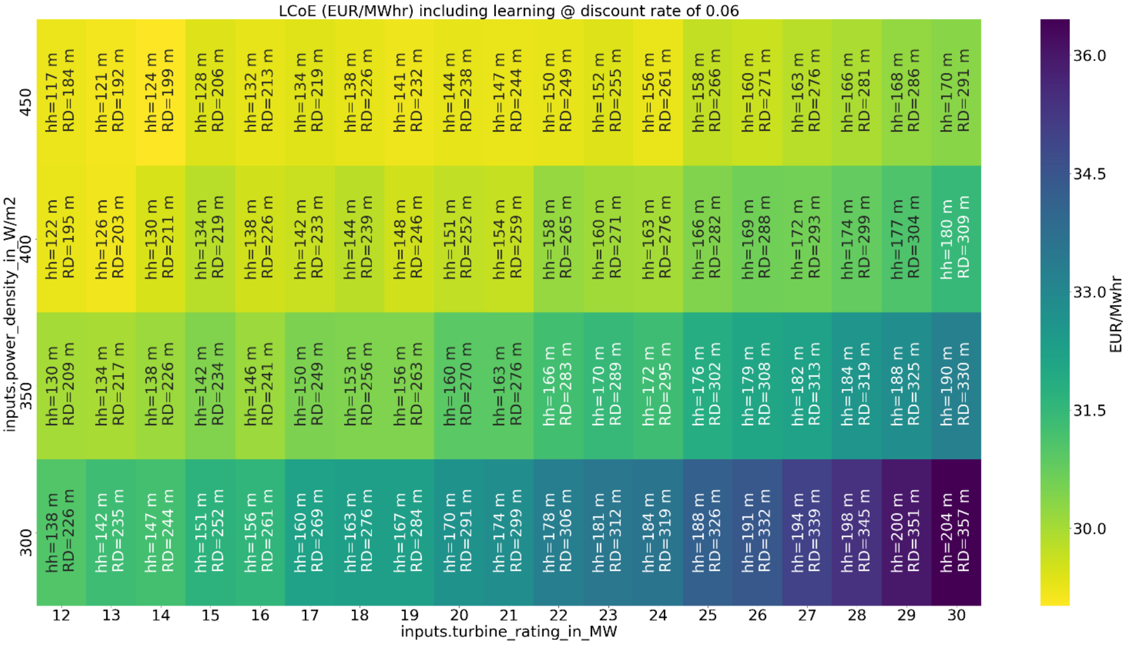


Considering a single WTG, the annual energy yield predictably increases with WTG rating. Moreover, larger rotors (with low specific power density) tend to produce more energy than relatively smaller, power-dense rotors of the same WTG rating. For a given specific power density, increasing WTG rating increases power generation in both partial and full-load regions of the power curve while keeping the rated wind speed constant. Increasing specific power density for a given WTG rating will result in an increase in rated wind speed meaning the WTG spends more operational time in below-rated power production mode. Moreover, the smaller rotor also produces less energy while operating at partial load. Hence, the reduced energy yield.

The annual energy yield of a wind farm is the product of the energy yield of a single WTG and the number of WTGs in a farm, reduced by the application of farm-level wake losses, electrical losses and availability losses. The trend for total farm annual energy yield with WTG rating and specific power density is shown in Figure 3-13. Increasing WTG rating for a given specific power density tends to see a small, gradual increase in farm energy yield. This is because while the number of turbines decreases, the increase in energy yield due to higher-rated WTGs just about compensates for this. However, increasing the specific power density for a given WTG rating leads to a reduction in farm energy yield because of the decline in single WTG energy yield while the number of power-producing turbines remains constant.

We have seen that farm CapEx increases with WTG rating while OpEx decreases. Moreover, farm energy yield shows a slight increase for higher-rated WTGs. The effect of these trends can be seen in the Levelized Cost of Energy (LCoE) calculated as the ratio of the discounted lifetime cost of a wind farm to its total discounted lifetime energy production. From Figure 3-14, it is evident that LCoE follows a similar trend to CapEx. For a given specific power density, LCoE increases with turbine rating. For high power densities this remains relatively constant between 12 MW and 20 MW, then increases gradually with further increase in WTG rated capacity. It is also evident that for a given turbine rating, larger specific power densities (smaller, power-dense rotors) give the lowest cost of energy. While wind farm CapEx was shown to decrease with specific power density, so does farm annual energy yield. However, the decrease in CapEx has a greater effect, and hence the declining cost of energy at higher specific power densities.

Figure 3-14: Estimated levelized cost of energy (in Euros/MWhr) for a 1000 MW wind farm project calculated at 6% discount rate. Generally LCoE is shown to increase with WTG rating, while larger specific power densities are shown to be more favourable. For large specific power densities, LCoE remains relatively constant between 12 and 20 MW.



3.4.2 Cost of energy sensitivity study

The LCoE value presented in Figure 3-14 is sensitive to a host of parameters. These include site-specific parameters like annual mean wind speed and wind speed probability distribution. Metocean and geological conditions also impact the LCoE. Considering that the focus of this study is specifically on the WTG and not foundation design, sensitivity to metocean and geological conditions is not studied. LCoE is also sensitive to financial parameters like the discount rate. WTG design parameters like the choice of drivetrain and tip speed ratio also impact the cost of energy. Finally, the cost of energy is also dependent on OpEx cost assumptions. Two separate sets of OpEx assumptions are studied to show this sensitivity.

3.4.2.1 Sensitivity to site conditions

Two scenarios with annual mean wind speeds of 8.5m/s and 9.9m/s were modelled to study the sensitivity of the cost of energy to mean wind speed. The choice of annual mean wind speed impacts the WTG and foundation wind loading. Moreover, it has a significant impact on energy production. The cost of energy for a 1000MW wind farm is plotted in Figure 3-15 showing the sensitivity to annual mean wind speed. The WTG configuration is fixed to the baseline case: a WTG with geared drivetrain configuration, design tip speed ratio of 10 and maximum tip speed of 100m/s. The WTG is designed for loads corresponding to the assumed annual mean wind speed. The plots shown are cost estimates for 2040 generated after applying learning rates to present-day WTG price estimates. The different curves in Figure 3-15 represent combinations of annual mean wind speed and specific power densities.

While WTG loads and hence component masses increase with an increase in mean wind speed, energy production also increases. Consequently, the cost of energy goes down for all WTG ratings. The cost of energy for the 8.5m/s mean wind speed case is 17% to

22% higher than the 9.9m/s mean wind speed case. Note, however, that the general trend of evolution of the cost of energy with WTG rating and specific power density remains unaltered.

Figure 3-15: 2040 LCoE (EUR/MWhr) sensitivity to annual mean wind speed shown using curves for different combinations of mean wind speed and specific power density.

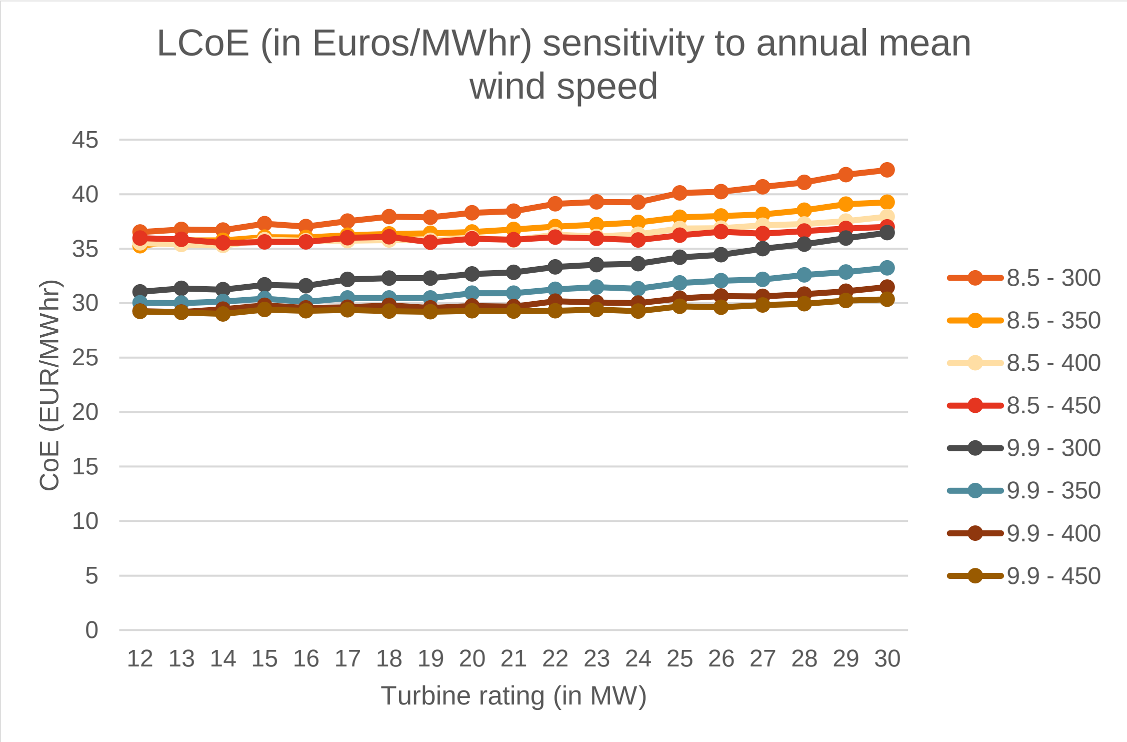


Figure 3-16: LCoE (EUR/MWhr) sensitivity to wind speed probability distribution for three different Weibull shape parameters.

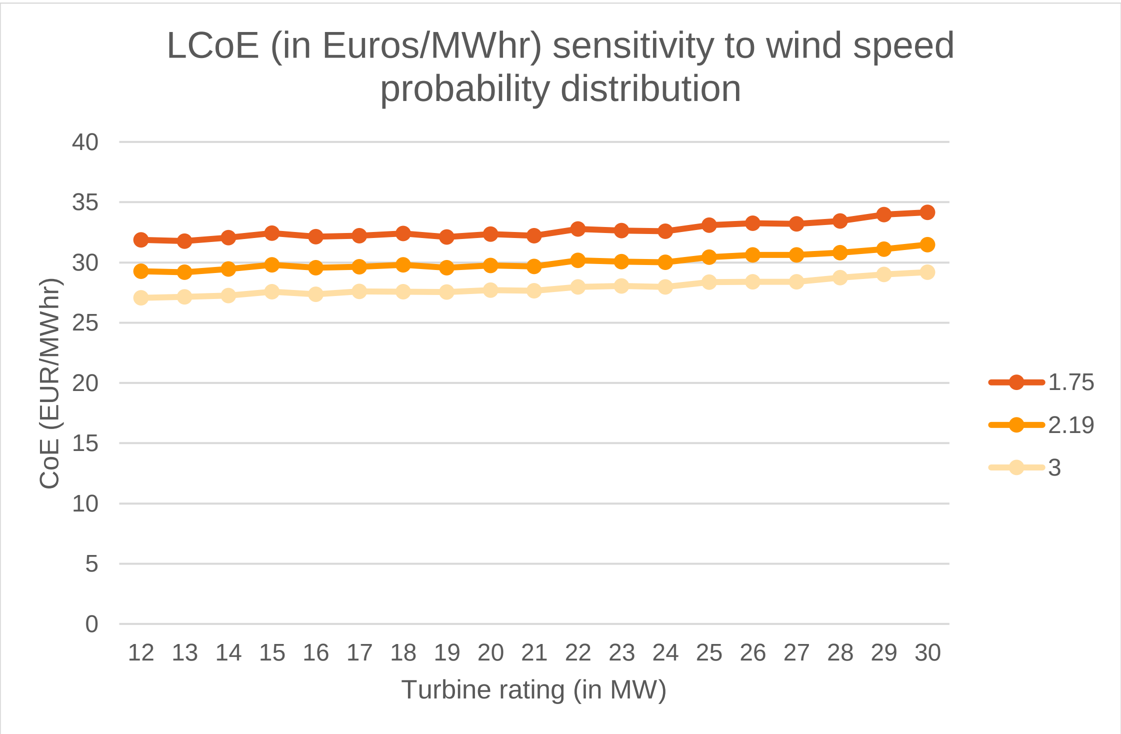
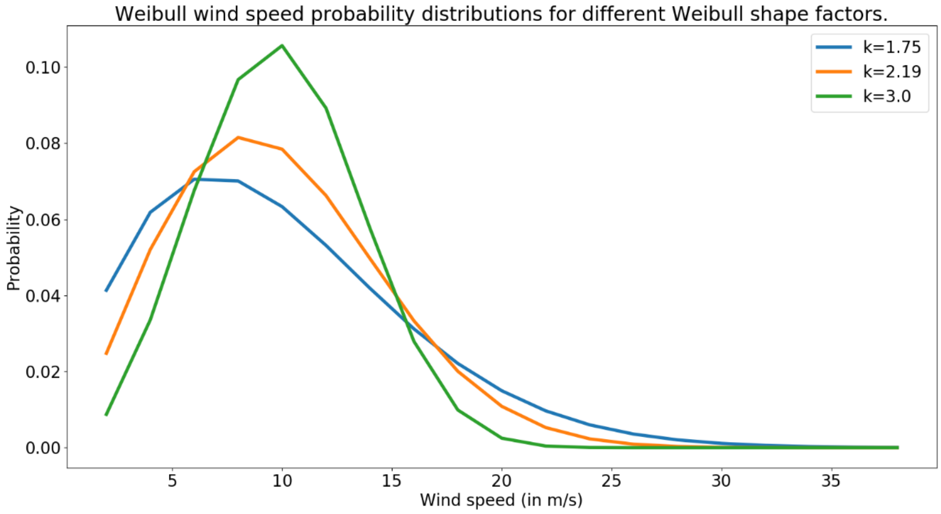


Figure 3-17: Weibull wind speed probability distributions for different Weibull shape factors for a mean wind speed of 9.9 m/s.



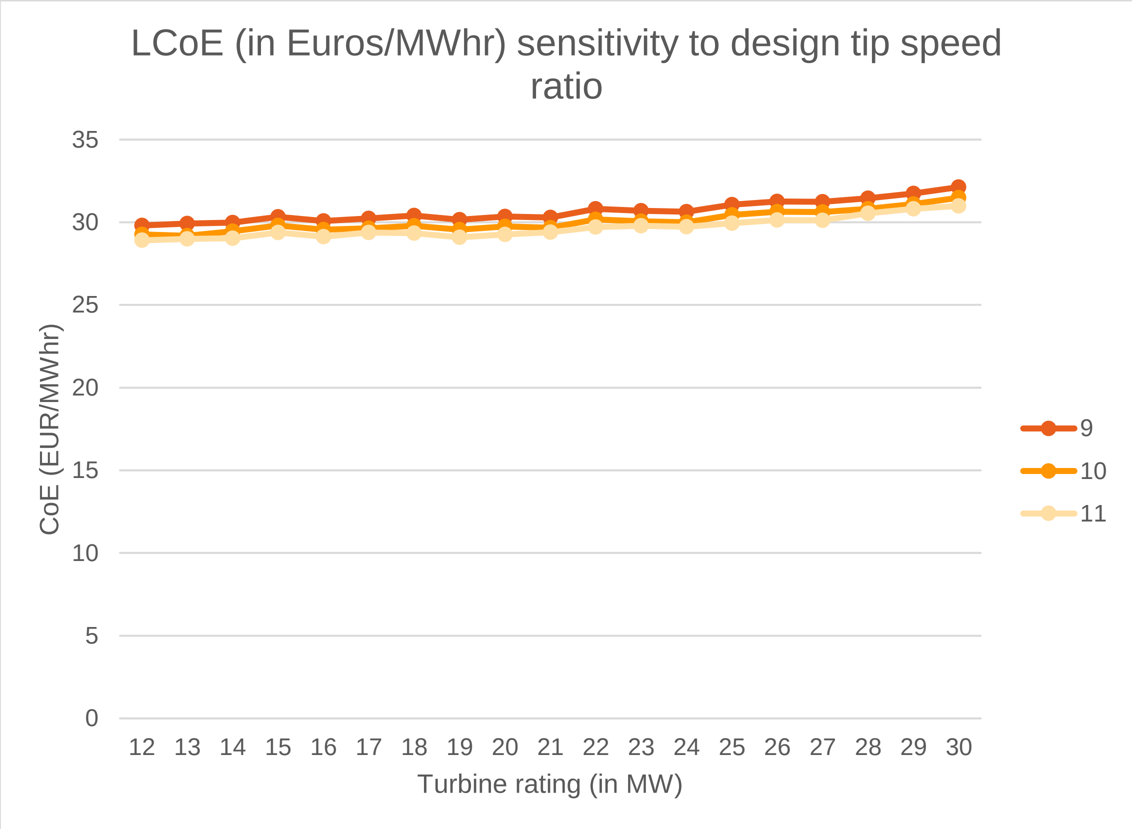
Also, the cost of energy for three different Weibull wind speed probability distributions for a WTG specific power density of 400 W/m2 is plotted in Figure 3-16. The three Weibull distributions (see Figure 3-17) for an annual mean wind speed of 9.9 m/s specified in Table 3-1 are modelled. As the Weibull shape factor increases from 1.75 to 3.0, the probability distribution in the mid-velocity range of 7 m/s to 17 m/s increases while that for low and high velocities decreases. This results in an increased energy yield and reflects in the lowering of the cost of energy with an increasing Weibull shape parameter. In going from a Weibull shape factor of 1.75 to 3.0 the LCoE decreases by roughly 15%.

3.4.2.2 Sensitivity to turbine design parameters

The cost of energy is also sensitive to the choice of turbine design selection parameters. First, we look at the impact of different tip speed ratios (TSR) and maximum tip speeds. Note that the maximum tip speed is scaled with tip speed ratio such that TSRs of 9, 10 and 11 correspond to maximum tip speeds of 90 m/s, 100 m/s and 110 m/s. This means that the critical wind speed at which a blade reaches its maximum rotational speed is kept fixed at 10 m/s and reduces the possible variations in energy yield between the different configurations.

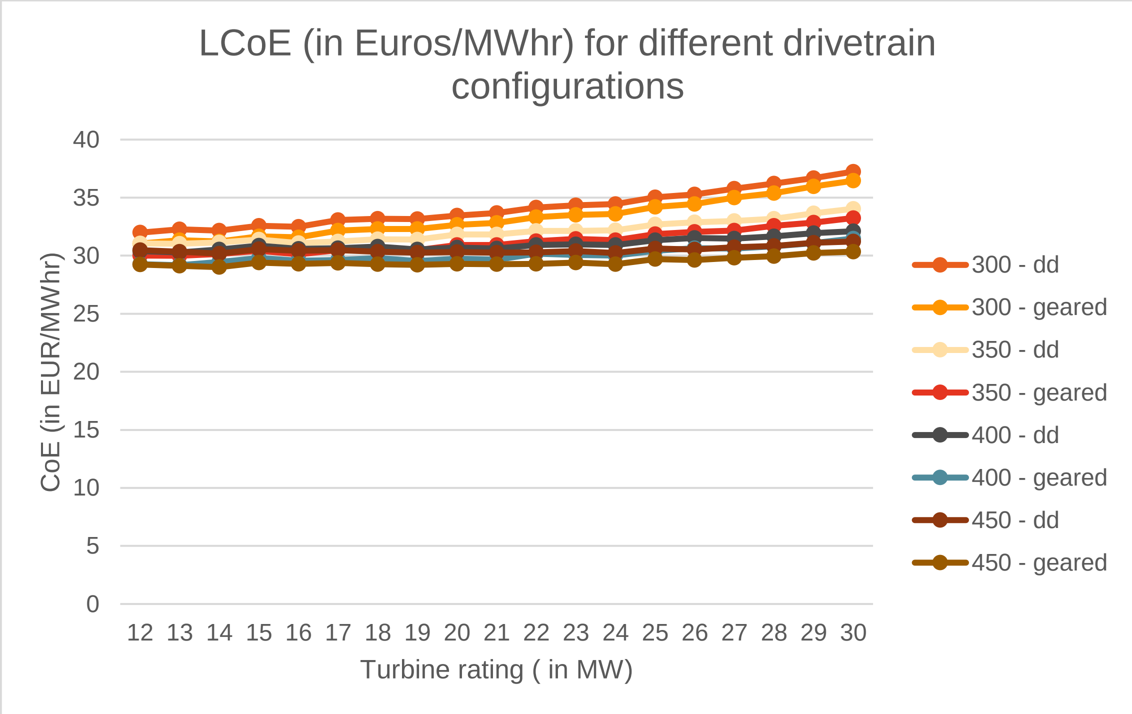
An increase in maximum tip speed allows for a lower gearbox ratio and hence a lighter, cheaper gearbox. A higher tip speed ratio also allows for a slenderer blade design which results in a lighter and cheaper blade design. These two factors combined result in a reduction of WTG cost and LCoE as shown in Figure 3-18. A potential reduction of 3.5% in LCoE can be realized by redesigning for TSR 11 from 9 while constraining maximum tip speed as described above. Note that a WTG with a default geared drivetrain configuration, a specific power density of 400 W/m2 and designed for loads corresponding to the annual mean wind speed of 9.9 m/s is assumed. The plots shown are cost estimates for 2040 generated after applying learning rates to present-day WTG price estimates.

Figure 3-18: LCoE (EUR/MWhr) sensitivity to design TSRs for a geared turbine designed for annual mean wind speed of 9.9 m/s, specific power density of 400 W/m^2 plotted for three different TSRs.



LCoE variation due to the choice of the drivetrain is shown in Figure 3-19. A medium-speed geared drivetrain with PMG is compared against a direct drive configuration. The results show that the direct-drive configuration is consistently resulting in a slightly higher cost of energy. This is because of the slightly higher cost of direct-drive WTGs. The additional cost of a larger, heavier generator and the structural components that support it is more than the cost savings accrued on account of omitting a gearbox. The LCoE for a direct drive based WTG can be 3-4% higher with the difference reducing as WTG rating increases. It is important to note that this difference is mainly on account of nacelle cost. Generally, O&M costs for direct-drive and geared WTG turbines also differ. This effect is not captured in this analysis. Moreover, the costs of rare earth materials used in permanent magnet generators are highly volatile.

Figure 3-19: LCoE (EUR/MWhr) for two different drivetrain configurations designed for annual mean wind speed of 9.9 m/s, design tip speed ratio of 10 and varying specific power densities.

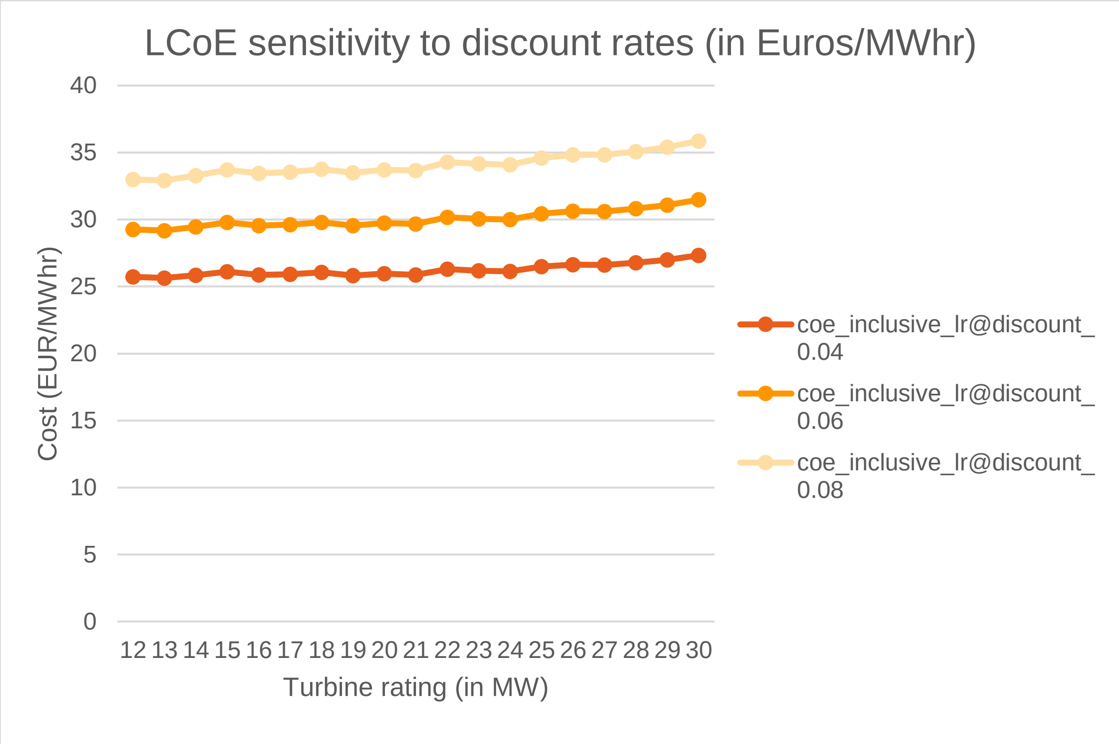


3.4.2.3 Sensitivity to discount rate

In Figure 3-20, the cost of energy for a 1000 MW wind farm is plotted for three different discount rates of 4%, 6% and 8%. The wind turbine configuration is fixed to the baseline case: a WTG with geared drivetrain configuration, a specific power density of 400 W/m2, a design tip speed ratio of 10 and a maximum tip speed of 100 m/s is shown. The WTG is designed for loads corresponding to an annual mean wind speed of 9.9 m/s. The plots shown are cost estimates for 2040 generated after applying learning rates to present-day WTG price estimates.

Note that reducing the discount rate reduces the LCoE. Wind farm CapEx investment is assumed to be entirely concentrated in the first year of operation. Hence, it is not impacted by discount rate assumptions. A lower discount rate does imply that OpEx investments in later years of wind farm operation are greater. However, it also implies that energy production in later years of wind farm operational life is valued more significantly. Overall, the LCoE is shown to decrease in Figure 3-20. Changing the discount rate from 4% to 8% results in a LCoE increase of roughly 28% showing that the LCoE is highly sensitive to this parameter.

Figure 3-20: LCoE (EUR/MWhr) sensitivity to discount rates.



3.4.2.4 Sensitivity to OpEx assumptions

Two different OpEx cases are modelled to understand the sensitivity of cost of energy to OpEx. The first is the baseline OpEx distribution given in Table 3-8 using DNV's in-house O&M cost modelling tool, O2M. This is DNV's best estimate of OpEx expenditure for a 1000 MW wind farm in 2040. The second is a more aggressive OpEx reduction scenario for larger turbines. This case implies a potential halving of OpEx for a 1000 MW wind farm built with 30MW WTGs compared to 12MW WTGs. The two scenarios are plotted in Figure 3-21.

It has been shown that CapEx increases with turbine rating. Therefore, an LCoE calculation omitting CapEx strongly favours smaller rated WTGs (see Figure 3-22). Adding the OpEx to the LCoE calculation results in a flattening of the cost of the energy curve. This is largely because larger WTGs have lower OpEx per MW. However, LCoE is still shown to gradually increase with WTG rating. This implies lower-rated WTGs are likely to be optimal from an LCoE perspective. Further assuming that OpEx will reduce more dramatically for higher-rated WTGs results in a reduction of LCoE for higher-rated WTGs and allows the optimal turbine to move towards a higher WTG rating, possibly in the range of 16 MW and 21 MW.

Figure 3-21: Annual mean OpEx (in million Euros) for a 1000 MW wind farm for two different scenarios.

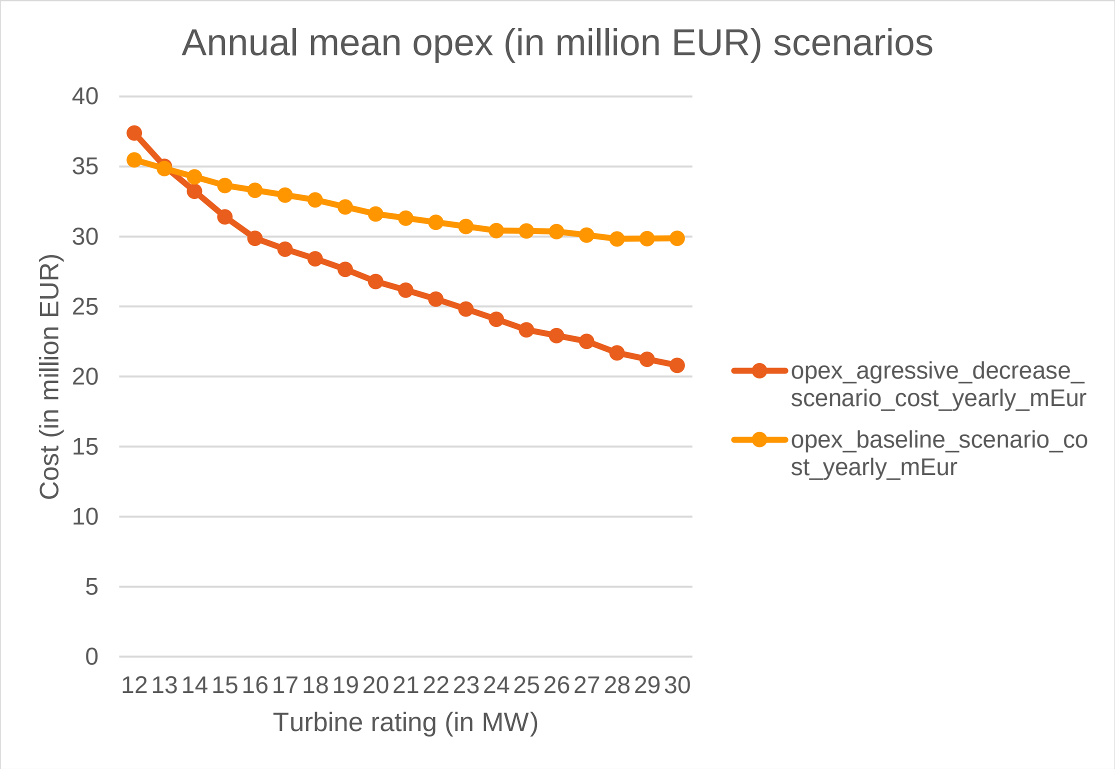
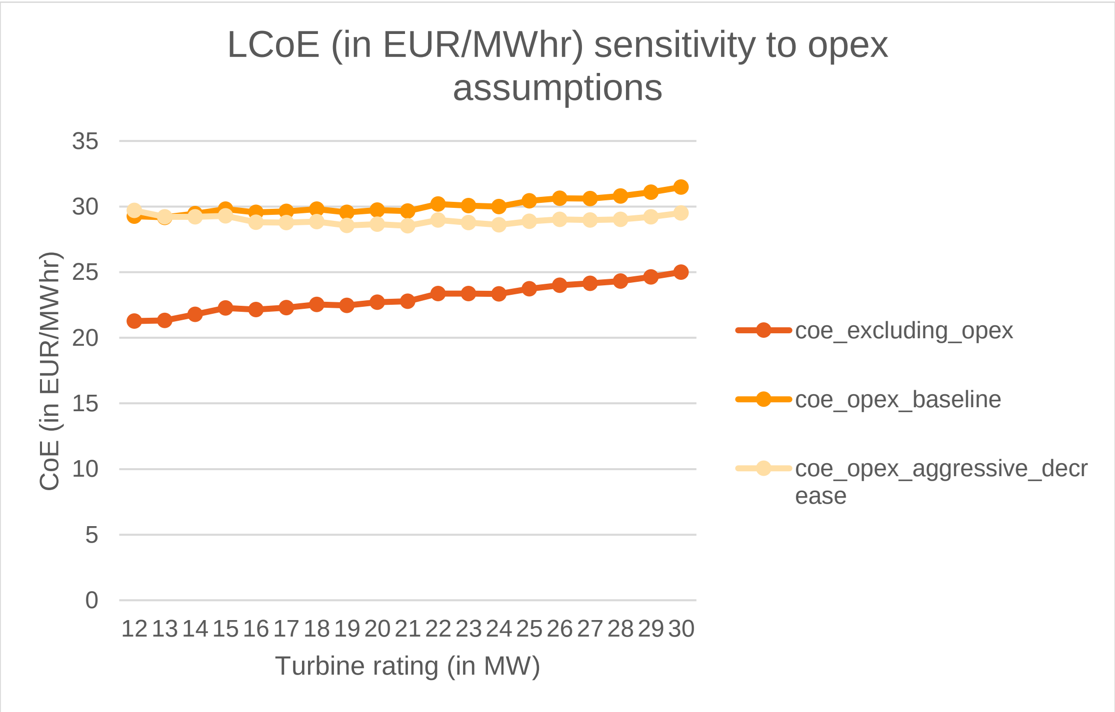


Figure 3-22: LCoE (in Euros/MWhr) for a 1000 MW wind farm for different OpEx scenarios.



3.5 Conclusion

Wind farm CapEx increases with increasing WTG rating and decreasing specific power density. This is largely driven by the largest contributors to cost: total turbines and foundations CapEx which increase with increasing WTG rating and decreasing specific power density. Wind farm OpEx is shown to decrease with increasing WTG rating. Moreover, farm energy yield increases only very slightly with an increasing WTG rating. Farm energy yield is influenced greatly by specific power density with larger rotors (low specific power density) generating more energy. Overall, the LCoE is shown to increase with increasing WTG rating implying that WTGs towards the lower range of this study, starting at 12 MW, are most optimal. Higher specific power densities (400-450 W/m2) yield the lowest cost of energy. For these specific power densities, the cost of energy remains relatively constant for WTGs between 12 and 20 MW. This means that the choice of the most optimal turbine is not straightforward and will depend on many factors including turbine design choices, site condition parameters, OpEx assumptions and discount rate.

The sensitivity of LCoE to the aforementioned parameters: site conditions, turbine design choices, OpEx assumptions and discount rate is also quantified in this section. Site conditions such as the annual mean wind speed and wind speed probability distributions are shown to strongly influence the cost of energy. However, these parameters do not affect the general trend of LCoE variation with WTG rating established in this section. LCoE is also very sensitive to discount rates. Lower discount rates yield lowest cost of energy. It is also observed that decreasing the discount rate further flattens the LCoE curve with respect to WTG rating. Turbine design choices such as a higher tip speed ratio and maximum tip speed can result in an LCoE reduction in the range of 3-4%. The cost assumptions made in this study also suggest that a PMG (Permanent magnet generator) geared drivetrain is likely to be cheaper than a direct drive WTG. It must be pointed out that this conclusion does not account for potentially smaller OpEx outlay for direct drive WTGs. Turbine design choices influence LCoE but significantly less so than site conditions. Finally, OpEx assumptions were found to influence both LCoE and the general trend of LCoE variation with WTG rating. It was demonstrated that by assuming a more aggressive OpEx reduction with WTG rating the choice of the optimal turbine could change and larger rated WTGs become more economical.

4 Technology and manufacturing limitations

It is not easy to identify any "hard" technology barriers that could limit future offshore WTG growth. Historically, the wind industry has always been able to design larger machines beating earlier predicted limits. However, WTG design is becoming increasingly challenging, especially in areas where technology is already pushed to its limits e.g. in blade design, pitch system design, main shaft suspension and gearbox design. For these components, "soft" technology barriers could become "hard" barriers or result in overly complex and/or exponentially expensive components.
In order to most effectively assess relevant aspects of future larger WTGs, it makes sense to look individually at the most important components constituting the WTG. Some drivers and constraints are unique for several components while others are very specific. The following subsections highlight the most important considerations. WTG foundations are not the focus of this study, however, the implications of floating substructures for WTGs are discussed in section 4.7.

4.1 Blades

WTG blades are one of the key parameters for influencing energy yield, loading of the structure, and WTG recognition factor. Blades are a topic of continuous development, and an increased blade length is essential for greater WTG sizes.

4.1.1 Tip clearance

Longer blades will see more tip deflection which will need to be accommodated with sufficient initial tip clearance. This tip clearance is established by having sufficient rotor overhang, drivetrain tilt angle, pre-bend and blade cone angle. Since larger WTGs will only see limited increase of rotor overhang, required tip clearance will mainly need to be established by drivetrain tilt and blade cone angle. Increasing tilt angle will increase rotor-generated fatigue loading on blades and hub components. Increasing cone angle will shift the static rotor centre of mass away from the tower thus increasing pitch actuator duty and pitch bearing loading. This means there are limitations to increasing tilt and cone angle and the resulting effects should be very closely investigated. If tilt and cone angles do not prove to result in sufficient clearance, tip clearance issues often can be solved with a fine pitch schedule around rated wind speed (to reduce the rotor thrust close to rated slightly) at the cost of some small amount of annual energy capture. Overall, from a technical design perspective, it can be concluded that tip clearance is not expected to become a limiting factor for further blade length increase any time soon.

4.1.2 Maximum tip speed and tip speed ratio

Maximum tip speed and Tip Speed Ratio (TSR) are key design factors for WTGs. For onshore WTGs, maximum tip speed is limited by noise regulations, but this limitation can largely be ignored for offshore WTGs.
A higher maximum tip speed allows to increase the TSR while keeping the wind speed at which the maximum rotational speed is reached constant. The increased TSR then increases the maximum rotational speed and decreases the maximum rotor torque. Consequently, significant savings are possible for a gearbox or for a direct drive WTG

generator. For a higher TSR, blades need to be designed slenderer, but with increased shell thickness to guarantee aerodynamic performance and structural integrity of the faster spinning blades. It is possible that eventually if solutions are found to enable higher tip speeds and TSR, the optimum blade profile becomes so slender that structural design limits will be reached.

For current offshore WTG designs, leading-edge erosion is the key reason for limiting the blade tip speed. Any rain, hail, snow and other particles hitting the blade can lead to deterioration of the coating impairing aerodynamic performance over time. Common mitigation methods at the moment are regular blade inspection, standard maintenance, and sometimes also expensive repair of damaged areas.
There is ongoing development into improved/disruptive technologies to deal with leading-edge erosion e.g.:

- Improved leading-edge protection material (e.g. PowerEdge from SGRE /16/)
- Reduced impact by weather (rain, hailstones) and environment (salt particles) through smart operation of the WTG, taking into account real-time environmental measurements and blade load sensor data and lowering tip speed during operation when needed
- Modularisation of the blade (e.g., easily replaceable leading-edge section or tip section, see also Section 4.1.4)

It is assumed that leading-edge protection technology advancements and the application of more advanced control systems will lead to maximum blade tip speeds significantly above 100m/s in the coming decades.

4.1.3 Blade materials

Carbon and glass fibre are the two main options for spar cap material inside blades, even though most blades use a variety of different materials. Carbon fibre is generally more expensive but stiffer and lighter, so the design of longer, lighter, more slender blades with less tip deflection is easier.

Future blade design is expected to increasingly make use of carbon fibre, especially if the trend of lower carbon cost price continues. Carbon cost price depends on raw material price, energy, production technology development and worldwide production capacity vs. demand (e.g. rising demand from the aerospace sector could lead to a temporary price increase). The current outlook is that in the long-term carbon cost price will come down with the forecasted increase in worldwide demand with production technology development and capacity following. The current trends in carbon fibre cost and technology are favourable toward developing even larger blades.
Another consideration is recyclability and the environmental impact of materials in blades. These questions are increasingly becoming important, and are starting to be addressed by manufacturers.

4.1.4 Blade design technology innovations

Blades are a topic of constant research and development, and engineers are continuously working on solutions to enable larger blade designs. Larger blade design present increasing challenges on blade performance and loading, quality and manufacturing.

An example of improving blade performance and loading is the application of active flaps, aiming to reduce high-frequency pitch motion on the whole blade to reduce loading and deflections and to improve aerodynamic performance. Another example is the research on plasma actuators installed on WTG blades that can lead to improved performance by reducing aerodynamic loading.

The application of carbon pultruded slats in blade spar manufacturing results in better strength quality compared to carbon fabric because carbon fibre strength is sensitive to fibre orientation and fibre orientation is near perfect in pultruded slats. Alignment of pultruded slats is easier to control in the manufacturing process compared to carbon fibre fabric that can wrinkle locally. The use of carbon pultruded slats is a current growing trend in large blade design.

Like for many other WTG components, modularisation could be an option to overcome certain manufacturing, transportation, installation or operation issues but blades generally do not lend themselves well to modularisation without compromising on mass and additional maintenance costs. For the onshore wind industry, segmentation of long blades can be the enabler in dealing with the local market transportation limits. For the offshore wind industry, there could be other reasons to investigate modularisation if it makes economic sense. Lower total manufacturing cost by reducing pressure on manufacturing facility space (also easier to start production in e.g. emerging markets) or enabling in-field blade module replacement, e.g. blade damage or leading-edge erosion (could increase with a future expected maximum tip speed increase), could be arguments for segmentation/modularisation of blades.

The current observed research and development in blade technology provides good hope that blade size can see further growth.

4.2 Rotor hub and systems design

The rotor design is a well-balanced system of the blade, pitch system and rotor hub. As rotor sizes grow, in theory, the moment loading is scaling with the cube of rotor diameter growth. However, recent trends have been for advanced control technology to essentially beat the scaling laws by enabling rotor growth while avoiding the worst penalties for the load increases. This was one of the main conclusions of the Innwind EU project /3/.
The interface between blade and hub is accommodated by a pitch bearing enabling pitch motion resulting in the large circular interfaces on blade root and hub side. There are currently no indications that this general rotor design principle will change any time soon. One of the important system design balancing acts is the dimensioning of the blade root diameter which strongly affects:

- The load-carrying capacity of the pitch bearing bolted connections
- The required pitch system capacity (actuation and bearing)

- The size of the rotor hub and blade root

4.2.1 Pitch bearing

The commonly most used pitch bearing type is the double race slew bearing, a stronger version of the single-race slew bearing used in the past for much smaller machines. In the largest offshore WTGs, pitch bearings are loaded to their limits, and it is unclear how much WTG rotors can grow before double race slew bearing diameters become so large that adjacent components simply become too large and expensive (e.g. cast hub size). From that point different, higher capacity type pitch bearings would be required like triple row cylindrical roller bearings, triple ring slew bearing, and double taper roller bearing, which are much more expensive and may also have some technical integration challenges. Disruptive technology would be needed to find a solution resulting in substantially higher pitch bearing capacity compared to the conventional double race slew bearing type without becoming much more expensive. Although more expensive than conventional, higher capacity type pitch bearings are available meaning that further rotor growth is possible from pitch bearing perspective.

4.2.2 Pitch drive system

For the largest offshore machines, both hydraulic and electrical pitch systems are deployed. Although hydraulic systems are more expensive compared to electrical pitch systems, they offer some advantages especially important for the offshore market:

- There is no risk of local ring gear wear as a result of high pinion loading at tooth 1 (fine pitch operation) resulting from ring gear deflections and/or failed lubrication potentially resulting in very expensive pitch bearing replacement. Hydraulic pitch systems do also have components that wear out, but these can be replaced during scheduled maintenance.
- The additional structural hydraulic pitch plate components needed for the piston actuator attachment also offer additional stiffness to the pitch bearing raceway that is bolted to the relative flexible blade root improving pitch bearing reliability.
- More suitable for cyclic pitch.

Both types of systems can be designed to meet increasing capacity requirements with larger rotors, but with electric pitch, there will generally be more pressure to increase pitch bearing diameter.

4.3 Large castings

For many of the modern WTGs cast components often form the backbone of structures, supporting other components and transmitting high loading from rotor to tower. Examples of these components are the rotor hub, mainframe, bearing housing(s) and for large machines possibly a hollow cast main shaft.
The wind industry does not seem to be close to any kind of absolute casting limit yet. Some large foundries are known to be able to cast components of more than 300 tonnes: roughly 3 times more than the largest cast components in the wind industry. Cast components above 100 tonnes would require current foundries supplying the wind industry to invest in increasing capacity of melting ovens and internal crane capacity.

Increasing cast component size requires larger flasks (assembled mould) which will increase manufacturing costs exponentially. Further innovation in WTG design modularising of large components could help to limit individual cast components' size and cost. Smaller size cast components will also result in more suppliers able to supply the industry, resulting in more competition and lower prices.

The difference between a good and bad design for casting process can make a huge difference in cost. Over the last decade, WTG designers have improved design for casting a lot, especially by making design for casting an integral part of the design process and including experts from the foundry in the design process.
The conclusion is that there are no technical limits for further cast component size growth. Imbibing the casting process into the design process and manufacturing innovation will help to limit cost increases that come with larger castings.

4.4 Drivetrain support

Most of the current largest offshore WTG structural drivetrain designs have a single Double Tapered Roller Bearing (DTRB) mounted directly to the structures using bolted connections or have two (separate) Widely Spaced Tapered Roller Bearings (WSTRB) located in a single cast bearing housing supporting a hollow cast shaft.

The single DTRB is a relatively easy bearing type to assemble the structural drivetrain but is heavy and very expensive. However, the high bearing cost is offset by the much-reduced mass in other parts of the structure as it does not require a bearing housing or shaft. Since this bearing type is expected to be loaded to its maximum capacity, it requires a lot of design experience and knowledge from the manufacturer. For this reason, it is not clear how much larger this type of bearing can grow before reaching a point of getting too large and expensive for most WTG manufacturers.

A WSTRB solution uses low weight and relatively cheap bearings but requires a single main bearing housing, a main shaft and a strict assembly procedure. The load-carrying capacity of this type of drivetrain system can be increased relatively easily. The total mass of this type of structural drivetrain is higher than the DTRB type.

The conclusion is that larger TRB type of structural drivetrain can be designed for larger future WTGs. It is expected that a hard technical limit is reached earlier with the DTRB type than for the WSTRB type. Disruptive technology (e.g., the use of plain bearings) has the potential for even larger capacities but is not expected to enter the market any time soon for rotor bearings, though plain bearings are already featuring in some gearbox bearings.

4.5 Gearbox

In the past, WTG gearboxes were regarded as the Achilles heel of geared wind turbine design, but lessons learned over time and strong technology development have changed this.

Possibly against expectation, Vestas has been able to develop a geared 15MW 236m rotor diameter WTG platform design (V236). New technology applied in this gearbox design compared to the smaller V164 platform and higher maximum blade tip speed made it possible to deal with the higher torque levels and at the same time keep the gearbox size relatively small and mass low. Also, a 3rd planetary stage had to be added to the medium speed geared system to achieve the required gearbox ratio.

With the step-up in applied gearbox technologies, it seems plausible that this will also enable even larger geared WTG platform design, but it is not clear to what size WTG this will be possible before potentially new and difficult to solve challenges arise.

4.6 Electrical systems

The process of electrical engineering within the context of WTG design accommodates two prime interfaces:

- the electromechanical energy conversion within the generator
- the requirements of and functionality to assist the external grid

The generator is specified to accommodate the torque/speed characteristic of the (incoming) rotating shaft. The profile of the torque/speed characteristic is determined by the control system throughout the active power operating range of the WTG, up to and including operation at nominal active power output. The WTG will deviate around nominal output, owing to gusts and lulls in wind speed.

At the electrical interface with the external network, it is important that the WTG is able to tolerate the electrical conditions like deviations in frequency and voltage as well as, in most cases with large scale WTGs, provide network support services.
With an increase in WTG rating generally comes an increase in WTG physical size and space. As such, electrical systems can be applied in a relatively straightforward manner to accommodate an increase in power production.

Therefore, in general terms, it can be considered that there are few barriers to the installation of larger electrical equipment within larger WTG structures. The primary issues which are affected are as discussed below.

4.6.1 Generator

The generator is specified to accommodate the torque/speed characteristic delivered to it from the main WTG rotor shaft. The utilisation and choice of a gearbox will influence the generator design, although generally with an upscaling of WTG rating, will come an upscaling of space available. The generator can be designed for integrated use within the nacelle structure.

An issue to consider, which is considered straightforward to address is generator bearings. With an increase in generator physical dimensions will come increased stresses on supporting structures of the stator and rotor systems. An area of stress is expected to be the rotor bearings, although considered more significant for direct-drive generators with single-end, shaft support.

Although bearings can be designed and indeed have been applied for a range of applications, the application of such within larger WTGs requires enhanced design considerations. Elevated heaving/acceleration forces will be applicable and to some degree, concentrated on the bearings because of the nacelle operational movement. As noted, however, this is an issue which can be addressed through relatively standard design procedures.

4.6.2 Power converter

The power converter, whether it is fully rated to accommodate the full output power of the generator or partially rated as in the case of Double Fed Induction Generator (DFIG), can be designed, constructed, and installed to accommodate and be an integral part of a larger WTG structure. Design considerations to address the application within larger-scale WTG technology should cover the heaving/accelerations moments applicable, where the power converter is installed within the nacelle, and to a lesser degree, towards the top of the tower. Given that power converters are installed within the marine shipping industry, standard processes are assumed to be similar and applicable within large scale WTG technology.

4.6.3 Power transformers

Power transformers can be designed for the most challenging environmental conditions. Application within increased capacity WTGs is expected to be without major issues. Again, as above, accelerations applied to the transformer as a result of the heaving of the nacelle should be considered.

4.6.4 Tower cables

Increased power ratings require increased cable sizes and/or increased voltages applicable to the down-tower cables. For an equivalent voltage, cable cross-sectional areas will increase to carry the increased currents expected.
At present, WTG systems operate at up to 3,300 V for the generator and converter systems and up to 66 kV as a terminal voltage for interconnection with the external electrical systems. Although up to 3,300 can be expected to continue for the foreseeable future, alternative and higher voltages to 66 kV could be 88 kV, 110 kV and 132 kV.
Where the voltage is increased, to reduce conductor material requirements and electrical losses, spatial requirements will be increased. Furthermore, with an increase in operating voltage will come an increase in the segregation of circuits from each other in the case of differing phases and also to ensure personnel are suitably distant from electrical systems.

Overall DNV considers an increase in conductor size and/or voltage to be manageable within a larger scale WTG structure.

4.6.5 Switchgear

Much effort was applied to the issues associated with a transfer of switchgear operating voltage from 33 kV to 66 kV. The same issues are expected to arise in the case of an increase in operating voltage from 66 kV, notably spatial requirements within the base of the tower or transition piece. The issues are considered resolvable.

4.6.6 Personnel Access

With an increase in WTG rating may come an increase in conductor size and furthermore may come an increase in operating voltage. An increase in both will bring about a need for greater space for equipment operations. In cognizance of this, operations personnel need to undertake their works activity safely.

Areas containing electrical equipment be it at the base of the tower or transition piece, throughout the tower or within the nacelle and hub need to be controlled with regards to access. The areas containing electrical equipment will need adequate space to facilitate suitable operating conditions but also space to allow personnel entry and access around equipment to undertake maintenance activities.

4.7 Floating substructures

Floating WTGs have recently received significant attention. The floating technology allows the building of wind farms in much deeper waters than possible with fixed structures and therefore opens up large additional areas for potential development. Manufacturers, as well as developers, are exploring their options, and research, as well as first commercial projects, are underway. So far, floating offshore wind installations use slightly smaller WTGs with positive track record to focus on floater development rather than dealing with potential problems of more recently developed WTGs. However, it is expected that floating substructure technology will soon, perhaps in the next decade, be mature enough to use the largest available WTGs to benefit from cost savings.

Floating substructures scale well, meaning that structure size increases more slowly than WTG size. This is due to the fact that floaters require a relatively high minimum size simply to stay afloat in all conditions, even without a WTG on top. This leads to the assumption that floaters will soon be equipped with bigger WTGs.

To build fully functioning floating wind farms, further developments in high voltage dynamic subsea cables and unique controller systems are required. However, research and development are ongoing, so DNV does not expect these to hinder the future WTG size development. As floating WTGs are assembled at the port and then towed to their intended position offshore, different installation considerations apply, and big port facilities are required. O&M faces a set of new challenges to bring technicians and spare parts from a service vessel onto another floating structure.

DNV’s general expectation is that WTGs will grow relatively unaffected by substructure technology. There is a large variety of available substructures, and it is reasonable to assume that they will be able to accommodate larger WTGs assuming sufficient time for technology build-up. It seems perfectly possible that the largest WTGs will be installed on floating substructures within the time horizon analysed.

Several companies are designing floating offshore WTGs different from a classic singular tower with an upwind rotor nacelle assembly combination. If these designs prove viable and attractive enough to overcome the current technology lock-in it is possible that the future offshore WTG sizes is affected by a set of new drivers and barriers. A whole technology shift like this is very difficult to predict and lies outside the scope of this study.

4.8 Structural dynamics of overall design

It is important to also investigate whether any fundamental issues will be encountered because of rotor and nacelle mass scaling in terms of dynamics. Larger and heavier combined rotor, nacelle, tower, and support structures naturally result in lower 1st and 2nd mode frequency and lower rotational speeds because of larger rotor sizes. The WTG and its control system, therefore, need integrated design, to identify and mitigate adverse dynamics. It is expected that adverse dynamic problems in WTG and support structure design can generally be solved and will not influence the potential growth of offshore WTGs.

4.9 Installation, operation and maintenance

A November 2021 Windpower Monthly article /17/, mentions that at the time of the article there are only 11 Wind Turbine Installation Vessels (WTIV) globally that can install WTGs greater than 10MW, that there are no WTIVs that can install 15MW+ WTGs, but that that is to change with six WTIVs under construction with capacity to install 14MW+ WTGs by 2023. The fast increase of WTG sizes has made it very difficult for the WTIV owners to keep up and expected vessel lifespan cannot only be met with expensive crane updates. The installation industry, for this reason, would be well served with a lower WTG growth pace and get more time to recover the cost of equipment renewal.
No big differences are expected in the operation or maintenance of WTG above 10MW. Therefore O&M is not expected to hinder WTG growth.

4.10 Ports

Ports play a vital role in the supply and logistics chain needed for assembly, installation, operation and maintenance of offshore wind farms. Large port investments will be needed to meet demands in the fast-expanding offshore wind industry. One of the main challenges will be to find enough port space to meet predicted growth from the current 2-3% installed capacity of the 2050 target /17/.

It is important that new ports will be designed for the larger turning circles that come with longer blades and that a proper “swept path” analysis is performed. The increase of nacelle mass can be compensated for with increased number of axles for the Self-Propelled Modular Transporter (SPMT) system. Water-borne sizes of vessels will go up with beam size increasing from 50m to 60m and overall length increases from 125m up to 200m.

In general, each port and installation strategy needs checking but it is not expected that growing WTG sizes will have a large impact on ports or visa-versa. It is expected that new ports, or existing port expansion, can and will come with sufficient capacity to handle larger WTGs.

4.11 Conclusion

There are few technical limits to the design and manufacturing of larger WTG parts than currently used in the largest WTGs (Section 4).

WTG size growth could lead to individual component costs to go up substantially, but if larger WTG size growth supports a lower cost of energy, then the supply chain is expected to adapt, as it has demonstrated in the past. Temporary barriers to obtain bearings, large casting, large forgings, carbon fibre and rare earth metals have occurred in the past but were resolved by companies expanding their portfolios and new market entrants filling component supply gaps. Similar hurdles are likely to occur in future years but will not stop growth and at worst result in temporary supply chain delays.

Larger WTG platforms require larger components and if these exceed existing manufacturing capacities, new investments are needed to deal with this. The growing offshore wind market and increasing WTG production numbers require an increase of new production capacity. This new capacity can be set up for larger size component production from the start, existing production still might need additional investment to deal with larger components.

5 Potential of standardisation

Increasing standardisation is attractive from the perspective of cost and quality. When WTG manufacturers or component/system suppliers foresee higher production numbers of the same product, more investment can go into product development and manufacturing technology (industrialisation) resulting in better product quality, lower production cost and beneficial effects for supply chain competitiveness, manufacturers, and markets generally.

The wind industry development of the past decades has resulted in an increasing production number of ever-larger WTG designs and a dedicated WTG supply chain as we know today. It may however be argued that continuously growing WTG size may have prevented the realisation of the full potential of standardisation on cost reduction.

In this section the potential of standardisation by maximizing future capacity of WTGs at a certain level and its impact on economies of scale and costs is investigated.

5.1 Standardisation of WTGs

It is not expected that any time soon a WTG platform will be sold under different brand names within the same market as seen in the car industry. However, for markets that are closed to foreign WTG manufacturers like China, this could be different with European designed offshore WTGs being manufactured under a license agreement by a local manufacturer. The application of lower LCoE WTGs with technology already tested and trialled could be attractive for local developers and owners. For the European manufacturer it could also be attractive if this establishes a better supply chain position in those markets due to larger combined order numbers. The decision of a European WTG manufacturer to develop a new and larger platform might be influenced by the chance of having a similar licence agreement.

Individual WTG manufacturers could also decide to join up and start to share supply of similar WTG sub-systems like semi-integrated drivetrain systems or direct-drive generators. However, DNV does not yet see any market indications that this will happen any time soon.

5.2 Standardisation at the WTG manufacturer

Often individual WTG manufacturers apply standardisation of manufacturing procedures by utilising similar technologies for different WTG models which promotes manufacturing optimisation in for example areas like:

- Line assembly of nacelles and hubs
- Blade manufacturing

Manufacturing optimisation will keep reducing the cost to some extent, but WTG unit numbers may not justify the large investment required for manufacturing process automation with the aim to further reduce costs.

Another area where WTG manufacturers apply standardisation is in designing larger WTGs with the aim of making use of the same components in previous design smaller WTG types as much as possible. Examples of this are:

- Yaw drives
- Hydraulic brake callipers
- Yaw sliding pad units
- Direct drive generator part unit

This can work if the larger WTG design has enough space to fit a larger number of the same component. Often this is possible up to a certain WTG size increase before a larger component size or system is needed. Fixing a WTG at a certain size is only expected to have a significant impact on this type of standardisation unless the next step up in WTG rating results in a very exotic and expensive solution.

DNV expects that generally technologies used in the WTG manufacturer’s onshore and offshore WTG platform designs will converge to improve quality and reduce costs. This can be regarded as a level of standardisation but is not expected to influence offshore WTG platform size growth.

5.3 Standardisation in the WTG supply chain

The supply industry of key WTG components is expected to gain importance in the future wind industry, especially when it comes to standardisation and economies of scale. Their investments in new product development, facilities and machineries will be targeted to supply components to the current, and to some extent, future design machines of the leading WTG manufacturers. If a WTG manufacturer designs a larger WTG platform that requires components beyond existing supply, supply chain investments will be needed resulting in a cost penalty that can only be balanced with sufficient production numbers and a substantial reduction in LCoE of the new WTG design.

5.3.1 Mechanical systems

In the current wind industry supply chain, there is an established level of standardisation. Good examples are mainly found in the electro-mechanical systems supply chain with the typical step size main dimensions of slew bearings, gearbox capacities, generator and converter capacities. Often this kind of standardisation is driven by leading a WTG manufacturer to first set a new WTG platform size and requiring multiple suppliers to supply the same mechanical components, spreading supply risk and at the same time improving market competitiveness. Sometimes suppliers are required to make investments at this stage and will already start to investigate and look for more customers. WTG manufacturers that follow with similar-sized designs at a later stage will adapt their mechanical systems to the already existing mechanical systems supply chain.

For smaller mechanical systems like yaw and pitch drives, often the size standard has been set by other industries. However, since WTG development is going fast with increasing specific requirements, also on this level the wind industry is starting the set the standards for the largest equipment.

Other examples include investment on the part of the supply chain in increased capabilities, such as in monopile fabrication or installation vessels, to facilitate continued expansion when sufficient confidence in the market is provided. This is expected to continue, such that larger WTGs will be followed by the requisite investment to enable their deployment, provided that doing so supports continued LCoE reduction and hence the further expansion of the industry.

A growing supply chain is emerging that can supply semi-integrated gearbox medium speed generator systems (semi-integration of gearbox and generator). This growing supply chain in combination with standardisation of system capacities will improve wind turbine reliability and will enable more market competition as smaller WTG manufacturers can buy complex systems off the shelf. Growing production numbers will be needed to make these more expensive products also cost-competitive when compared to bespoke design of conventional high-speed DFIG drivetrain configurations. Pressure from the market to lower cost and at the same time improve drivetrain system reliability could prove to be an excellent driver for further standardisation of this key system.

Direct Drive generators are designed integrally to the individual manufacturer’s wind turbine concepts. This is the main reason that no supply chain industry, supplying standardised direct drive systems to the market, will establish in the foreseeable future. Standardisation of specific direct-drive generator concepts within a manufacturer’s platform design configuration portfolio can happen when the wind turbine platform is deployed in different markets with different annual mean wind speeds. From LCoE perspective it could prove sensible to vary rotor diameter and keep generator rating, and therefore generator design, the same.

5.3.2 Blades

Ever-increasing blade length requires costly new manufacturing facilities. As it is cost-inefficient for WTG manufacturers to offer multiple blade lengths and/or different WTG platforms, WTGs might not be optimised for all markets, but manufacturing savings justify offering only a few distinct wind power densities.

Manufacturing of blades requires expensive tooling and lots of experience. Blade moulds are extremely expensive but are expected to become cheaper in the future with the introduction of disruptive technology such as 3D printing technologies aimed at long blade production. 3D printing of blade moulds would make worldwide blade production easier as it requires less experience in mould making technology and blade moulds can be produced near the blade production site avoiding the transport of large moulds.

In the coming decades, it is not expected to see standardised large blade designs coming to the market because blade design (size, mass, performance) is one of the key competitive differentiators between wind turbine manufacturers. It is also questionable if standardisation in blade design would be a good development because healthy competition in blade design is important for the needed technology development.

With larger blades, pressure is increasing to get more capacity out of the blade design. This can be achieved with higher strength material (and likely more expensive material like carbon fibre), but also by improving blade manufacturing quality (lowering defect and tolerance levels). Achieving higher manufacturing quality (which actually becomes more challenging with larger blades), requires manufacturing experience and additional manufacturing investment. A likely future scenario is that we will see a limited number of blade manufacturers (more than today), supplying competitive, high-quality blades to multiple wind turbine manufacturers from semi-automated factories. The blade designs from these factories can vary for different OEM blade designs, but the manufacturing process and procedures will be highly standardised. This high level of standardisation and semi-automated manufacturing will make it easier to set up new manufacturing facilities around the world, where needed to supply the local market.

5.3.3 Structural components

Large rotor and nacelle structural components are hard to standardise as these are designed to the individual manufacturer's WTG concept designs. They comprise competitive design solutions and are sized to the individual platform design and load capacity requirements. Standardisation in this area is not expected to play an important role in reducing WTG cost at any substantial scale in the next decades.

5.4 Economies of scale

Successful onshore WTG models have been produced in the thousands and only a handful of onshore WTG models have been produced in the tens of thousands. When comparing this level of WTG production numbers on a general scale with other industries' production numbers, WTG production numbers are on the lower side of the scale of single build and mass production:

- Mass production (e.g. cars being produced >100.000); and
- Single build (ships commonly being produced <50 of a single type)

Production numbers of single WTG models are insufficient to justify high investment in assembly automation as observed in the car industry. The constant historic WTG size growth is a likely reason that a level of semi-automation, flexible enough to follow the WTG growth, has been established. There are a number of factors that influence offshore WTG model production numbers:

- WTG model size: a larger size offshore WTG type requires fewer numbers to meet project demand
- WTG model production life: the longer the production life, the larger the production numbers of the same type
- Market demand: growing market demand will generally result in larger production numbers for the WTG manufacturers

- Competition: more competition offering suitable project WTG models will result in generally lower production numbers at the individual WTG manufacturers

The forecasted future offshore market demand is expected to also drive individual WTG production numbers to go up steeply from today's numbers, in combination with the other mentioned factors influencing the final production numbers of individual WTG models. However, production numbers of individual WTG models are not expected to go beyond production numbers observed for the onshore wind industry and for this reason no disruptive change in assembly processes is expected towards semi or fully automated any time soon.

Larger offshore WTG model production numbers will result in larger supply chain order of components. Sufficiently large orders result in discounts to be negotiated with the supply chain, especially for bespoke WTG model components. Very large component or system order numbers could result in the supply chain setting up dedicated productions lines with increased levels of manufacturing automation potentially resulting in further cost price reductions. However, a very clear future outlook on production numbers is needed before large investments will be made.

5.5 Conclusions

Standardisation and increasing production numbers have the potential to reduce costs. Especially in the WTG supply chain of components and systems, there is potential for this to happen, but the continuous growth of WTG platforms has generally prevented this from taking place. In a growing offshore wind market, with WTG manufacturers producing the same WTG platform type for longer periods and different manufacturers producing similar sized WTG platforms, there is potential that this could change. But the WTG supply chain industry will need a very clear view of future production numbers before it invests heavily in cost-reducing production streamlining and automation.

6 Potential societal benefits

The rapid development of offshore wind brings challenges outside of the technical sphere, including social and environmental aspects that must be considered in the context of both individual projects and the wider industry. In general, increases in WTG size are not expected to have significant negative impacts in these areas and thus are not expected to constrain further machine growth.

There is increasing pressure within the offshore wind industry for projects to realise “local content” whereby employment and investment are returned to the areas in which the projects are located; this historically has related to the financial support provided to offshore wind, although appears to be continuing even as this support reduces in parallel with cost reduction. Changes to WTG size may have some effect on the labour requirements of manufacturing (and those for foundation fabrication, for example), but this is likely to be minor and countered by the opportunities for market growth facilitated by reduced LCoE (to which larger WTGs would be expected to contribute). Therefore increasing WTG scale is not expected to negatively impact human capital related to the offshore wind industry.

The construction and operation of offshore wind projects is not expected to change fundamentally with larger WTGs i.e. similar processes, equipment, personnel and locations will likely continue, and therefore the impact of noise, pollution and operational safety would be expected to be broadly similar for future projects using larger machines. Technological changes, such as advanced access strategies or alternative fuels for vessels, are likely to have a more significant impact on these aspects than is the WTG size. Noise during operation may be impacted by WTG design, for example in higher tip speeds, but this is not necessarily directly related to WTG scale and is also influenced by technology development (in leading-edge erosion protection), and therefore not specifically considered here. In general, larger WTGs may enable minor reductions in harm in some areas, for example through reduced O&M requirements and therefore reduced vessel operations, with a consequential reduction in vessel noise and emissions.

Recently, there has been significant attention on the impact of offshore wind on material consumption and recycling, and DNV understands that the WTG manufacturers are actively supporting more sustainable design through increased recycling and alternative disposal. This approach is likely to percolate into both onshore and offshore wind, and again is not directly related to proposed scaling of offshore machines; overall, the environmental footprint of future WTGs should reduce through these efforts and those of the wider supply chain. For example, for a given installed capacity, the total mass of blades may increase somewhat with larger WTGs, which would increase material consumption; however, this is likely to be countered by such blades being of a more sustainable design, and therefore the overall impact being reduced.

As more offshore wind is installed, it will compete – and potentially conflict – with other marine users. Some firm spatial constraints are considered within wind farm development, such as shipping lanes or military uses, whilst others are less firm and therefore present risks to development arising from local objections. Fishing is one such example of the latter and has recently shown to be contentious with respect to offshore wind development in both Europe, Japan and the US. The use of larger WTGs within such wind farms is not likely to have a significant impact on fishing conflicts whilst fishing is prohibited within the wind farm area, although if this changes in future, then larger WTGs – which require increased inter-WTG spacing – may provide greater opportunity. The impact of offshore wind on fishing communities and industries should not be disregarded, although overall it is expected that conflicts are more likely to be resolved through dialogue and improved practices rather than with larger WTGs, per se.

Larger WTGs are inherently more visible, with increased tip height as well as larger plan areas. This increases the visual impact of a project and increases the distance over which such impact may be observed. Therefore, the use of larger WTGs may increase the visual impacts of offshore wind farms and increase the distance to shore at which visual impacts become acceptable. In the North Sea, wind farms are being developed further from shore such that visual impact is typically a minor consideration, and therefore the effect of increased visual impact from larger WTGs is unlikely to become a significant factor. In emerging markets, however, the visual impact of next-generation machines may restrict the development of sites closer to shore which, unlike in the North Sea, have not yet been developed with smaller WTGs and therefore some increased impact could result from upscaling of WTGs.

Overall, whilst larger WTGs would be expected to have some impact on non-technical societal factors, these are more likely to be affected by other technology development occurring independently of WTG size and therefore would not be expected to directly constrain WTG growth.

7 Past growth rates

The current wind industry took shape not only because of WTG manufacturer's growing capabilities, but also requiring the full supply chain and installation industry to step up. Over time, WTG size increased in incremental steps with the industry learning at each step on the way from failures, managing risks and then moving forward again.
By looking at WTG developments in the past assumptions can be made how WTG are expected to evolve in the future.

The development of new WTG models often follows the same pattern; first, a baseline platform is developed and then over time upgrades and new variants are introduced.

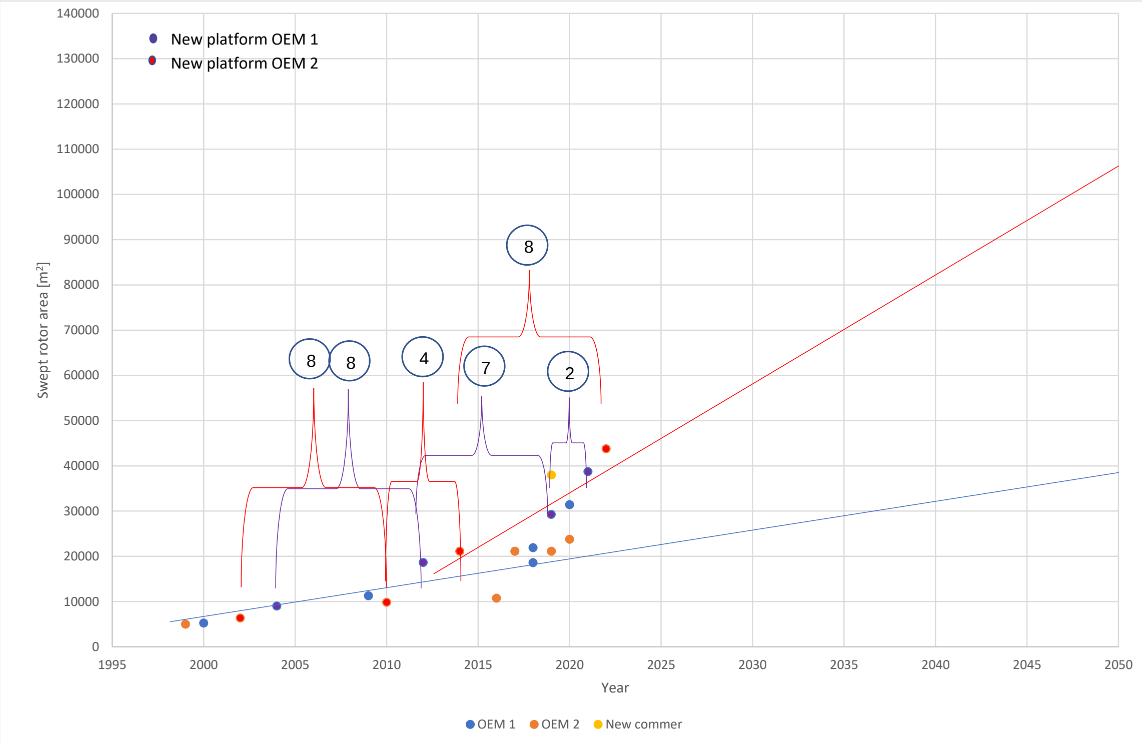
- *Platform:* Is what can be considered a base WTG model. Creation of a new platform typically prompts development of completely new nacelle structural components (hub, nacelle frame, etc.) as well as a completely new drive train.

- *Upgrade*: Is a minor increase in the rated power of an existing model.

- *Variant:* Is typically adding a new rotor to a WTG platform which normally also would entail minor updates of the structure and drive train.

It is in the interest of any WTG manufacturer to keep selling the same WTG platform for as many years as possible and try to stay cost-competitive over time by developing new variants and upgrades. If the platform capacity limit is finally reached, the WTG manufacturer could be forced into development of a new WTG platform. Figure 7-1 illustrates how WTG rotor sizes offered by relevant offshore WTG manufacturers have increased over time.

Figure 7-1: Swept rotor area and new platform development of different WTG manufacturers over time



Note: The number in the circles shows the number of years between turbine platform introduction.

DNV is of the opinion that WTG development over the past decades has not been exponential, but actually along two separate linear growth lines illustrated in Figure 7-1. The two lines illustrate two different WTG size developments rates for the period 2005 - 2015 (blue line) and the period 2015 - 2025 (red line) which happened for the following reasons:

- Many technical issues with on and offshore WTGs in the period 2000-2010 have slowed down WTG growth development during and beyond this period.
- In 2019 the offshore market was disturbed by a newcomer from the onshore market, presenting an offshore WTG with a 1.6 larger swept area compared to the largest available WTG of the established offshore WTG manufacturers at that time

It appears that individual WTG manufacturers release new WTG platforms roughly every 5-8 years, which can be roughly observed in Figure 7-1. In this period up to the next release, incremental WTG size increases are achieved by increasing blade length and uprating of the drivetrain. Also, in this period generally, a number of platform improvements are made based on feedback from the field and production.

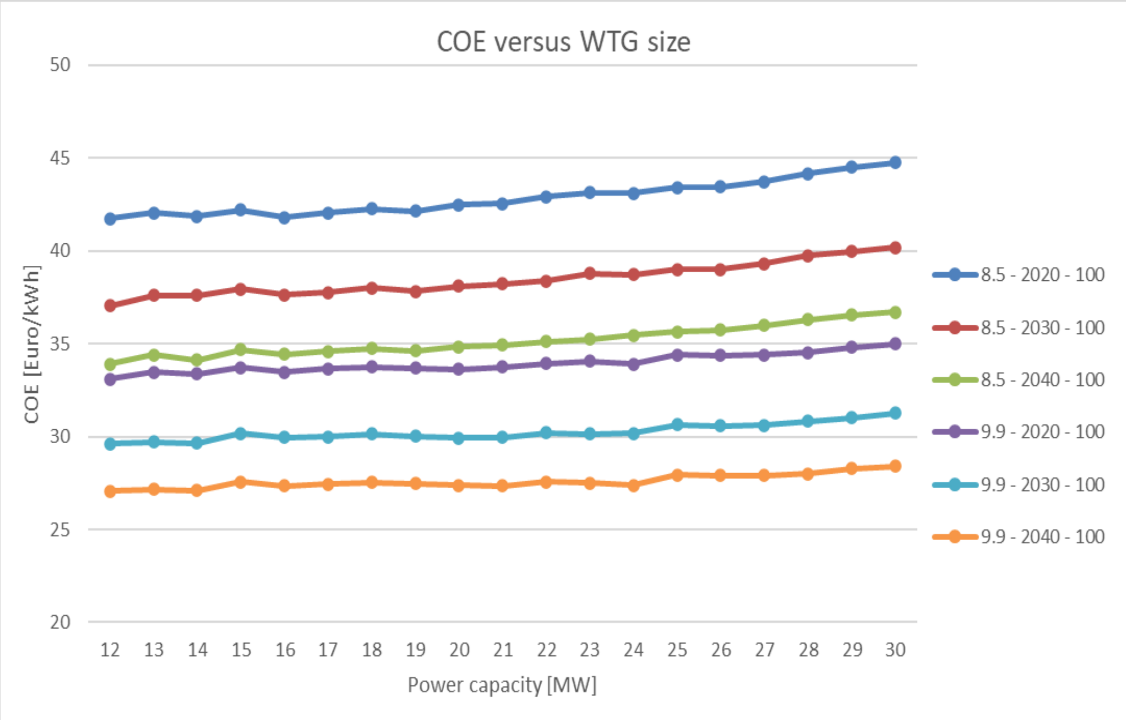
8 Future WTG growth and standardisation conclusions

Recently, four leading offshore WTG manufacturers announced the development of their next generation offshore WTG platform with sizes significantly greater than their previous largest platform and following the expected market trends. The development of these larger WTGs has only been possible by the ever-growing WTG design knowledge and experience build up in the industry.

Current market expectation trendlines suggest that offshore WTGs will keep on growing in the future. The 2019 Wood Mackenzie market report on Next-generation wind turbine models /14/suggests that 20MW, 300m rotor diameter offshore WTGs could enter the market before 2030, with the right growth and investment in supply chain, ports and installation vessels. This level of WTG growth expectation seems further to be confirmed by offshore wind farm developers requesting for planning permission for potential use of very large WTGs (over 20MW and rotor sizes around 300m) for wind farm projects to be developed in the near future (before 2030).

DNV is of the opinion that there are no hard technical limits to design WTGs larger than the current latest generation models (Section 4), but T.A. analysis (Section 3) shows that there is no clear cost advantage to develop WTG larger than 12MW and reductions in Cost of Energy (COE) are better served by reducing manufacturing costs. In Figure 8-1 this is presented with representative COE trendlines produced from the Turbine.Architect (T.A). database of results with COE trendlines being near horizontal in ranges 12-18MW (8.5m/s AMWS) and 12-20MW (9.9 m/s AMWS). Beyond these ranges, COE trend clearly starts to go up.

Figure 8-1: T.A. COE estimates for 2020, 2030 and 2040, geared machine type, AMWS=8.5 and 9.9m/s, maximum tip speed=100m/s, discount rate=0.06, optimal power density results only



The horizontal trendline sections are sensitive to future CapEx or OpEx (see Section 3.4.2.4) cost developments. Future OpEx cost reduction will influence COE trendlines favouring development of larger WTGs, but future Capex cost increase would do the opposite. Because it is not easy to predict future Opex and Capex cost development, it is also difficult to estimate future WTG platform size development.

Figure 8-1 shows the larger COE reduction that can be achieved from increasing learning rates over time (see Section 3.2.6). Although future learning rates are estimated, this time-based COE trend clearly indicates that it might be better to put more energy in reducing costs of (existing) WTG platform designs rather than developing new larger WTG platforms. This observation is expected to lead to:

- New WTG platform development to focus more on general cost reduction in manufacturing, installation, and operation instead of attempting to design for a more favourable balance between Capex and Opex with larger WTG design resulting in limited or no COE improvement
- Longer WTG platform development cycles compared to the past (5-8 years, Section 7) and larger WTG production numbers of the same WTG platforms, improving economies of scale resulting in lower COE

Figure 8-2 and Figure 8-3 show T.A. COE trendlines for 8.5m/s and 9.9m/s AMWS for different points in time, including estimated conservative and progressive development trajectory scenarios (accompanying data presented in Table 8-1 and Table 8-2).

Figure 8-2: Estimated COE of optimal power density WTG designs and development trajectories for 2020, 2030, 2040, AMWS 8.5m/s, maximum tip speed=100m/s, discount rate=0.06

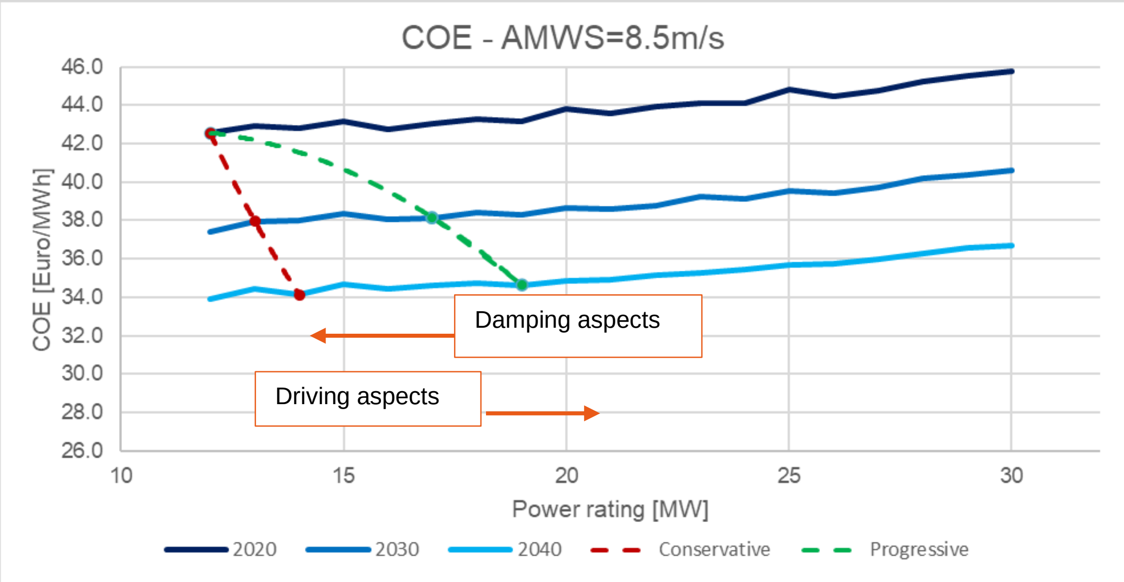


Table 8-1 Estimated future development trajectory WTG sizes, 8.5m/s AMWS

Development	Time period	Blade max. tip speed	Rating	Rotor diameter	PD	COE
[-]	[year]	[m/s]	[MW]	[m]	[W/m²]	[Euro/MWh]
Conservative	2020	90	12	209	350	42.6
	2030	95	13	217	352	38.0
	2040	100	14	211	400	34.1
Progressive	2020	90	12	209	350	42.6
	2030	95	17	249	349	38.1
	2040	100	19	246	400	34.6

Figure 8-3: Estimated COE of optimal power density WTG designs and development trajectories for 2020, 2030, 2040, AMWS 9.9m/s, maximum tip speed=100m/s, discount rate=0.06

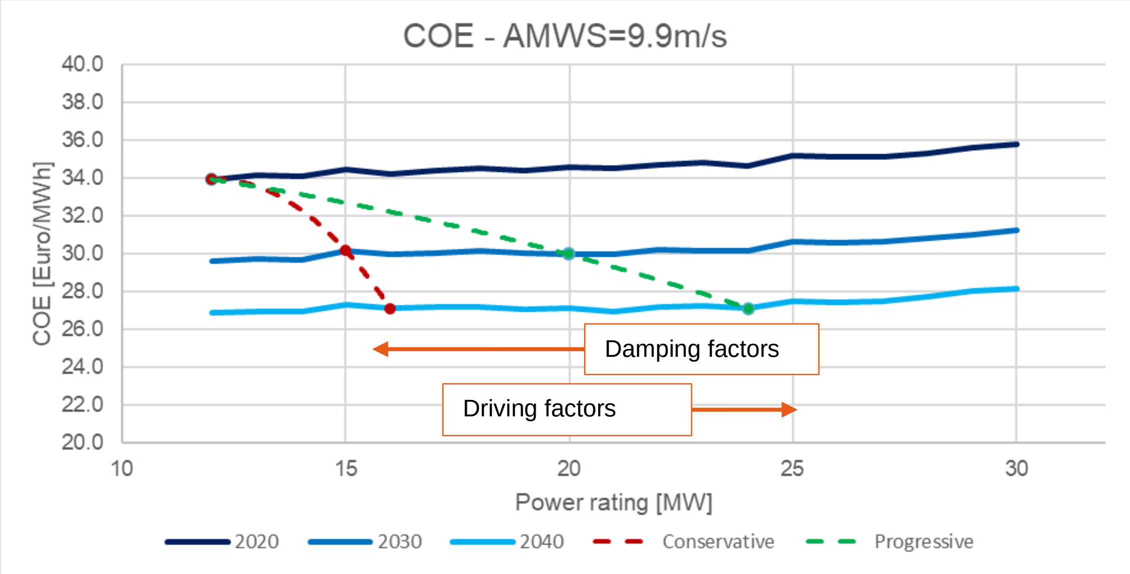


Table 8-2 Estimated future development trajectory WTG sizes, 9.9m/s AMWS

Development	Time period	Blade max. tip speed	Rating	Rotor diameter	PD	COE
[-]	[year]	[m/s]	[MW]	[m]	[W/m^2]	[Euro/MWh]
Conservative	2020	90	12	184	451	33.9
	2030	100	15	219	398	30.2
	2040	110	16	226	399	27.1
Progressive	2020	90	12	184	451	33.9
	2030	100	20	238	450	29.9
	2040	110	24	261	449	27.1

How the WTG sizes of next-generation platforms will develop depend to large extent on how the factors that influence the slope of the COE trendline will develop.
Potential influencing factors that drive towards development of larger WTG design are:

- Disruptive O&M developments, (e.g. future clustering of wind farms for O&M operations will result in lower fixed O&M cost by sharing of vessels and staff)

Potential influencing factors that I can drive or dampen the development of larger WTG design are:

- Raw material prices (e.g. current steel prices have more than doubled over the past 2 years, but could also come down again)

Potential influencing factors that I will dampen the development of larger WTG design are:

- High costs of developing new larger WTG platform designs

- Heavy investments that are needed to manufacture larger components (new machinery) or assemble larger nacelles (new larger assembly space needed)

Over the past 1.5 years, the price of iron and steel has more than doubled due to high energy prices and high demand with supply that has fallen behind. Similar trends can be seen for other import materials required in WTG production. Although this is expected to be a temporary peak, sustained high steel demand and higher production costs of reduced carbon steel in the future are expected to result in steel prices plateauing at significantly higher levels than observed over the last decade. Higher raw material prices directly impact WTG Capex of which 30-40% is estimated to come from raw material costs. Next to higher raw material prices, future paradigm changes of not only thinking in terms of lowest COE but also in terms of lowest CO2/kWh /15/, will also favour smaller WTGs simply because bigger WTGs relatively require substantially more material than smaller ones. Lower CO2 emissions from installing and maintaining a lower number of larger WTGs is not expected to compensate for this impact.

The current T.A. numerical analysis has focussed on fixed bottom offshore structure mounted WTGs. Floating offshore support structures favour larger WTGs because large initial floater size and mass is needed before any WTG size is considered (Section 4.7). A growing floating wind market growth could therefore influence WTG design in favour of larger WTG platform design, but up to 2040, the impact of this growing market is not expected to have a very large impact on WTG platform size growth.

With current knowledge, DNV expects that the four leading offshore WTG manufacturers will keep their latest design offshore WTG platforms in production up to 2030, and potentially even longer. The next-generation platforms coming to the market after 2030 are expected to see an increase in rated power into the 15-24MW range but with limited increase in rotor diameter, staying in or close to the 238-261m range (Table 8-2, progressive, period 2030 and 2040).

An upside of limited WTG rotor size growth is that different manufacturers' largest WTG types will be of similar size which is beneficial for the installation (Section 1.1**Fout! Verwijzingsbron niet gevonden.**) industry and has the potential to increase standardisation and industrialisation in the supply chain. This could also work the other way around; the design of a new WTG with a size outside the standard offshore WTG installation industry capacities is likely to be less competitive and might withhold a WTG manufacturer to do so.

Although limited WTG size growth is expected, future next-generation WTG platforms will be substantially different from previous platforms at a more detailed design level. Major advances in design optimisation and manufacturing technologies are expected to make it easier and cheaper to build the WTG and to install and operate the WTG in the field.

9 References

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