DTU Library

Key Performance Indicators and Target Values for Multi-Megawatt Offshore Turbines

Chaviaropoulos, Panagiotis K. ; Natarajan, Anand; Jensen, Peter Hjuler

Published in:
Proceedings of EWEA 2014

Publication date:
2014

Document Version
Publisher's PDF, also known as Version of record

Key Performance Indicators and Target Values for Multi-Megawatt Offshore Turbines

Panagiotis K. Chaviaropoulos
CRES
tchaviar@cres.gr

Anand Natarajan
DTU Wind Energy
anat@dtu.dk

Peter Hjuler Jensen
DTU Wind Energy
peje@dtu.dk

Abstract:

This work is in the context of the FP7 Innwind.EU Project whose objective is the high performance innovative design of beyond state-of-the-art 10-20 MW offshore wind turbines. The assessment of innovation necessitates a framework where different designs can be compared against a reference on the basis of key performance indicators (KPIs). Following the European Wind Industrial Initiative the Levelized Cost of Electricity (LCOE) and its driving components are investigated, while quantifying the sensitivity of LCOE to its constituent factors. Methods whereby innovation in design can reduce component cost and lower LCOE are investigated. Targets are set to the LCOE by associating with specific technologies and high Customer Net Present Value (NPV).

Keywords: Large wind turbines, KPIs, LCOE, offshore

1 Introduction

The research focus is on quantifying the LCOE of innovative designs for very large offshore turbines (10-20 MW) at deep waters (50+ meters) investigated in the FP7 project Innwind.EU.

The LCOE of a wind farm depends on:

- All turbine capital costs (C)
- Balance of plant including the foundation, electrical cabling, logistics (BOP)
- FCR – fraction of capital costs paid each year
- Annualized O & M (OPEX)
- Annual energy production, AEP

$$LCOE = ((C+BOP)*FCR+O\&M)/AEP \quad (1)$$

The cost models for assessing turbine component cost may be mass-scale based [2] or loads based [3], but it should follow market trends and design rules. Conventional up scaling of the wind turbine would result in most of the component mass following a cubic power law with the rotor diameter, which results in heavy and costly wind turbines at the 10MW scale. To be cost effective, appropriate technology needs to be developed whose implementation leads to design load mitigation and thereby reduced component mass without compromising power production.

Offshore wind turbines also have a large BOP cost associated with them which can increase with the distance of the wind farm from the shore, increased water depths and with the type of soil bed. Therefore reducing LCOE also requires significant BOP cost reduction based on site specific design and logistics. In the present study, the BOP cost is taken as one unit comprising of offshore sub structure cost, transportation and installation, without involving its details. The primary focus is on the turbine and its constituent technologies.

Table 1: LCOE values and targeted evolution

LCOE evolution	OFFSHORE	
	Abs.	Rel.
LCOE by 2010 (€/MWh)	106,9	100
LCOE by 2015 (€/MWh) (-10%)	95,57	89
LCOE by 2020 (€/MWh) (-20%)	84,77	79

LCOE calculation follows the methodology and assumptions [1] introduced by EWII (European Wind Industrial Initiative) for monitoring progress in the SET-Plan. The anticipated LCOE time-evolution under an accelerated RTDI scenario is also compatible with the EWII figures (Table 1). The Net Present value (NPV) or Internal Rate of Return (IRR) is computed for a wind farm owner based on electricity pricing guidelines [4], wind farm efficiency and assuming a variation of BOP costs over the years.

Keeping the EWII assumptions for OPEX we investigate the CAPEX and Capacity Factor targets that will allow meeting the 2020 LCOE target value (85 €/MWh) of Table 1.

Further, turbine design parameters which have a significant influence on the LCOE, BOP and the turbine CAPEX are sought. We have identified three candidates for which preliminary investigations regarding their down-stream influence have been made. These are: a) the rotational speed of the rotor, b) the tower-top mass and c) the design thrust of the rotor.

For the targeted designs, a plot of annual cash flow for the customers versus the LCOE depicts the trade-off in the choice of technology.

LCOE CALCULATOR		*Reference 5MW*	*Classical Upscale 10MW*	*Innovative 10MW*	*More Innovative 15MW*	*More Innovative 20MW*
Single Turbine Cost (€)		**7.500.000**	21.213.203	17.365.057	30.634.018	47.442.733
BoP per Turbine Cost (€)		**10.000.000**	20.000.000	16.842.529	22.795.071	28.284.271
Upscaling exp Turbines			**3,00**	**2,42**	**2,80**	**2,90**
Upscaling exp BoP			**2,00**	**1,50**	**1,50**	**1,50**
Total Plant Capacity (MW)	**P**	300,00	300,00	300,00	300,00	300,00
Size of Wind Turbines (MW)	**Pt**	5,00	10,00	10,00	15,00	20,00
Turbines Cost (€/kW)	**Ct**	1.500	2.121	1.737	2.042	2.372
BoP Cost (€/kW)	**Cb**	2.000	2.000	1.684	1.520	1.414
Capital Investment Cost (€/kW)	**C**	3.500	4.121	3.421	3.562	3.786
O&M Costs (€/kW/y)	**O&MF**	**106**	**96**	**86**	**81**	**76**
O&M Costs [incl. fixed annual costs, (€/MWh)]	**O&M**	30,25	25,49	20,89	19,26	17,71
Balancing Costs (€/MWh)	**BC**	3,00	3,00	3,00	3,00	3,00
Project Lifetime (y)	**N**	25	25	25	25	25
Capacity Factor (%)	**Cf**	**0,40**	**0,43**	**0,47**	**0,48**	**0,49**
Nominal Discount Rate (%)	**dn**	0,07	0,07	0,07	0,07	0,07
Inflation Rate (%)	**i**	0,02	0,02	0,02	0,02	0,02
Real Discount Rate (%)	**d**	0,05	0,05	0,05	0,05	0,05
Capital Recovery Factor (%)	**CRF**	0,074	0,074	0,074	0,074	0,074
Summation of Discounted Future Expend	**SFE**	13,557	13,557	13,557	13,557	13,557
Present Value of Total O&M (€)	**SO&M**	473.853.240	436.389.747	399.995.059	380.728.910	361.462.761
Annual Energy Production (MWh/y)	**E**	1.051.200	1.130.040	1.235.160	1.261.440	1.287.720
Levelized Investment (€/y)	**LI**	77.452.842	91.202.278	75.699.278	78.823.519	83.789.595
AnnualLDiscounted O&M (€/y)	**DO&M**	34.953.600	32.190.120	29.505.480	28.084.320	26.663.160
Annual O&M / Capital Investment (%)	**O&M(%)**	0,030	0,023	0,025	0,023	0,020
	LI/E	73,68	80,71	61,29	62,49	65,07
	DO&M/E	33,25	28,49	23,89	22,26	20,71
LCOE (€/MWh)		**106,93**	**109,19**	**85,18**	**84,75**	**85,77**
Contribution of CAPEX (Turbines) (€/MWh)		31,58	41,54	31,11	35,83	40,77
Contribution of CAPEX (BoP) (€/MWh)		42,10	39,17	30,18	26,66	24,30
Contribution of OPEX (€/MWh)		33,25	28,49	23,89	22,26	20,71
Contribution of CAPEX (Turbines) (%)		0,30	0,38	0,37	0,42	0,48
Contribution of CAPEX (BoP) (%)		0,39	0,36	0,35	0,31	0,28
Contribution of OPEX (%)		0,31	0,26	0,28	0,26	0,24
		1,00	*1,00*	*1,00*	*1,00*	*1,00*

Figure 1: LCOE Calculation for classical and innovation-based up-scaling

2 Meeting the LCOE 2020 Target

The CAPEX (attributed to each wind turbine of the typical wind farm) is split into two parts, one addressing the turbine itself and another for the balance of plant (BoP), where for offshore we also include the offshore foundation system (from the sea-bed to the transition piece). Working still with the EWII parameters the offshore CAPEX (3 500 €/kW for a 5-7 MW) is now split in Turbine Cost (1 500 €/kW) and BoP Cost (2000 €/kW) as depicted in Figure 1 (column “Reference 5 MW”). The annualized CAPEX and O&M costs are now computed based on an inflation adjusted discount rate of 5.4% for a 25 year lifetime and for a fixed wind farm capacity of 300MW. The LCOE computations are formulated in an excel sheet as shown in the figure.

Up-scaling from 5 to 10MW with state of the art turbine technology (column “Classical up-scale 10 MW” in Figure 1) is still too expensive in comparison with the LCOE targets of Table 1. A possible pathway to reaching the target value, resulting from a combination of classical up-scaling [2], [3] and technology improvement anticipations (column “Innovative 10 MW” of Figure 1) [4]- [6], is shown in Figure 2. At 5 MW turbine, the maximum size with available mass and cost data ([7] – [12]), is projected to the 10+ MW scale. The overall target CAPEX is distributed to its major cost sub-components (rotor, nacelle, tower, offshore support structure etc). Following technology learning curves and pre-design calculations, the LCOE for up scaled turbines and associated innovation is shown for a 10 MW, 15MW and 20 MW wind turbine.

The effect of up-scaling with innovation, wherein the scaling exponent of components is greatly reduced from the traditional cubic law is shown in Figure 2, where cost and up-scaling target values for all the major cost components are derived for a 10MW wind turbine rating. As can be seen the net exponent of up scaling with innovation at the 10MW level can be lowered to about 2.4 from the traditional (classical up scaling) level of 3. It is also anticipated that such innovative design can increase the net capacity factor from levels of 0.43 presently to about 0.47.

REF TURBINE (EWEA 5 MW)								UPSCALED TURBINE			
Capacity (MW)	5,00						Turbine Upscaling Exponent 2,42	Capacity (MW)	10		
Turbine Cost (M€/MW)	1,500					Subcomponent costs (M€)	Upscaling exponents	Turbine Cost (M€/MW)	1,742		Subcomponent costs (M€)
Turbine Only	Rotor	Rotor lock	0,0000	0,2357	1,00	0,000	2,50		0,2276	1,00	0,000
		Blades	0,2220			1,665	2,30	0,2121			3,695
		Hub	0,0137			0,103	2,80	0,0156			0,271
	Nacelle systems	Gearbox	0,1291	0,2979		0,968	2,60	0,1368	0,3014		2,384
		Generator	0,0703			0,527	2,00	0,0605			1,055
		Rotor brake	0,0132			0,099	2,50	0,0135			0,235
		Nacelle cover	0,0135			0,101	2,50	0,0138			0,241
		Nacelle structure	0,0280			0,210	2,50	0,0287			0,499
		Couplings	0,0000			0,000	2,50	0,0000			0,000
		Shaft	0,0191			0,143	2,70	0,0210			0,365
		Yaw system	0,0125			0,094	2,70	0,0137			0,239
		Bearings	0,0122			0,092	2,70	0,0134			0,233
	Electrics & control	Pitch system	0,0266	0,0767		0,200	2,30	0,0254	0,0685		0,443
		Variable speed system	0,0501			0,376	2,00	0,0431			0,752
	Tower		0,2630	0,2630		1,973	2,50	0,2693	0,2693		4,691
	Other		0,1300	0,1300		0,975	2,50	0,1331	0,1331		2,319
						7,525					17,422
BoP Cost (M€/MW)	2,000					Subcategory costs (M€)	BoP Upscaling Exponent 1,50 Upscaling exponents	BoP Cost (M€/MW)	1,684		Subcategory costs (M€)
BoP Only		Foundation system	0,4400		1,00	4,400	1,50	0,4394		1,00	7,400
		Offshore transportation and installation	0,3000			3,000	1,00	0,2519			4,243
		Offshore electrical I&C	0,2600			2,600	2,00	0,3087			5,200
						10,000					16,843

Figure 2: LCOE Calculation for up-scaling with innovative design

3 Effects of up-scaling on LCOE

In this section we discuss the results presented in Figure 1 and Figure 2. The “classical up-scaling” (using same technology) and “innovation-based up-scaling”, which adopts new technologies with a strong potential for cutting the costs (and weight) but also increases the offshore wind farm capacity factor are utilized. All LCOE and NPV computations herein are based on fixed capacity wind farms of 300 MW.

Effect of up-scaling on the wind farm capacity factor: Even classical up-scaling has a positive effect on the capacity factor of a large offshore wind farm. It is seen in Figure 3 (calculations performed with the CRES-Farm engineering model [13]) that the wind farm aerodynamic capacity factor increases with the size of the turbine from 5 to 10 MW by nearly 2.5 percentage units and from 10 to 20 MW by another 2.5. Further, we have shown in [6] that innovative rotor design, such as low-induction / low-thrust rotors of increased swept area may produce more power with the same turbine loading. It is seen that by using the less loaded – larger diameter – turbines, the wind farm capacity factor increases by nearly 3 percentage units.

Half of these 3 units are due to the increased annual production of the larger diameter turbine and half from the reduction of the wake losses due to the lower axial induction and lowered number of turbines.

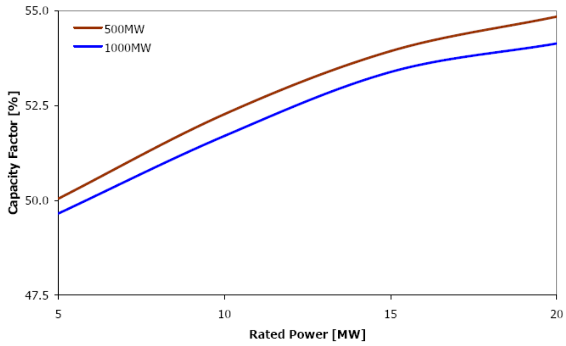

Figure 3: Effect of turbine size on the aerodynamic capacity factor of large offshore wind farms

Assuming that the turbine size effect and the innovative design effect on wind farm capacity factor can be superimposed the net capacity factor of a large offshore wind farm can increase by 3 percentage units for a standard design and by 7 for an innovative design from 5 to 10 MW (see CFs in Figure 1). Though the LCOE of an up scaled turbine decreases slightly as mentioned above, the IRR for the customer of the wind farm reduces, if there is no innovation driving the cost of the turbine down as can be seen from Figure 4. Further in order to have positive IRR for the offshore wind farms, it is required to subsidize the revenue from generation. The chart in Figure 4 uses a subsidy of €0.03/KWH on top of the market power price.

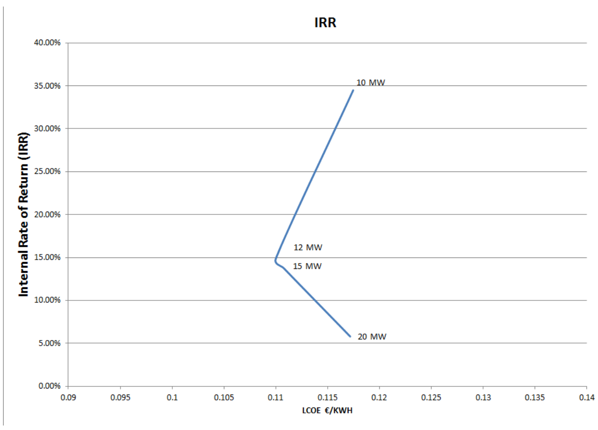

Figure 4 : Effect of Up scaled turbine rating on the LCOE and Internal return rate with conventional scaling exponents (no innovation)

With increase in turbine rating beyond 15 MW and with innovative designs, the rate of decrease in LCOE for fixed capacities can be achieved. Also moving to innovation can lower the requirements for subsidies. If the scaling exponents for innovative designs are utilized with lowered subsidies, then moving to 20 MW wind turbine sizes result in increased IRR as seen in Figure 5 in comparison to turbine ratings of the order of 12 MW for a fixed capacity wind farm. Here the subsidies are based on the power output per wind turbine and are of the order of 0.01€/KWH above the power price.

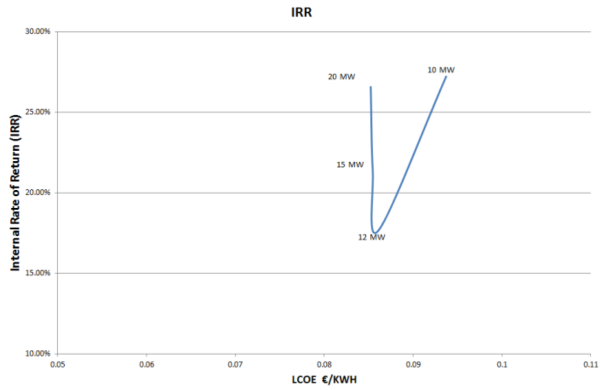

Figure 5: Effect of Innovative turbine Design as a function of rating on the LCOE and Internal return rate with reduced scaling exponents

However the rate of decrease in LCOE is lower than the rate of increase in cash flow. Decision to move to 20 MW turbine ratings may be based more on return of investments rather than the LCOE target.

<u>Effect of up-scaling on CAPEX</u>: In classical up-scaling the scaling exponent for CAPEX is λ_c=3 for the turbine and its main subcomponents [2], [3] and λ_c=2 for the BoP. UPWIND project showed that for a fixed water depth, the electrical infrastructure and connection scales-up with the power of the turbine (λ_c=2) and similar assumptions are made in [12] for the other BoP cost categories (offshore foundation system, transportation, installation etc. For a fixed water-depth and a bottom-mounted design it is logical to assume that the offshore foundation system (monopile, jacket) weight is scaling-up in two dimensions and not in three (as constrained by the fixed water-depth), thus λ_w=2. Going to the "innovation-based up-scaling" figures we shall assume λ_w values lower than 3 and 2 for the turbine and BoP parts respectively. For the turbine every such λ drop is directly related to technological improvements while for the offshore substructure the fact that the hub height in not up-

scaling linearly but adjusts to a fixed blade-mean sea level clearance leads to λ_w values closer to 1.7 than 2.0.

Since the turbine λ_c is still larger than 2 but the BoP λ_c is now smaller than 2 the contribution of the BoP in LCOE at a given water depth reduces as the rated power increases along with the contribution of the CAPEX. A fixed BOP cost that scales with the number of turbines is added to the cost per MW to account for costs such as logistics of installation and number of electrical cables. For bottom mounted designs, the optimum sizing of the turbine derives by balancing the extra turbine cost with the lower BoP cost per MW as the turbine size increases. Though as water depth increases, larger turbines may be the optimal solution, the optimal turbine size is still very dependent on how successful the new technologies in turbine and offshore substructure designs are implemented. Also, larger turbines are not necessarily optimal for floating applications where the floater cost is normally scaling up with λ_c larger than 2.

The main findings of Figure 1 and the discussion followed are summarized in Figure 6 where the re-distribution of the total CAPEX between the turbine part and the BoP part as the turbine size increases is evident.

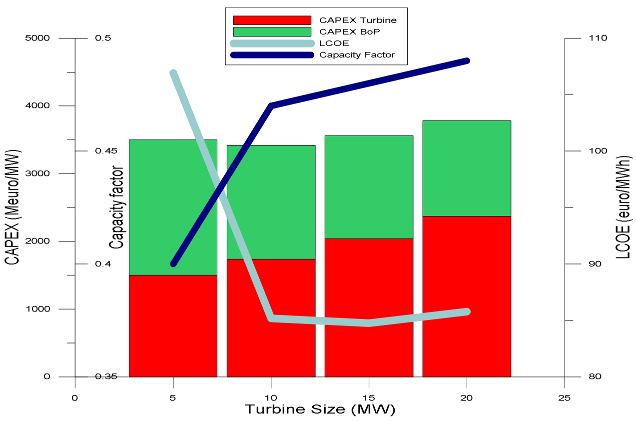

Figure 6: Turbine size influence to LCOE and its main drivers

4 Up-scaling Sub-components

In this section we shall discuss up-scaling laws focusing on the three major sub-components of Innwind.EU interest, the blades, the drive train and the offshore support structure. The discussion here justifies some of the assumptions made for the up-scaling exponents of Figure 2.

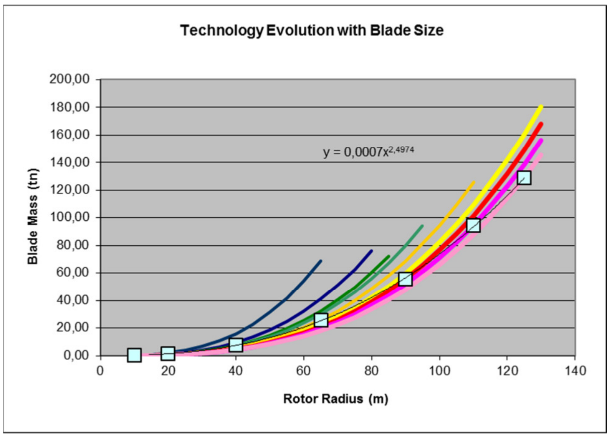

Figure 7: Blade mass up-scaling. Learning curve [2]

Figure 7 shows the correlation of the blade mass with the rotor radius, demonstrating also the technology evolution in time. All colored curves are cubic but each one of them corresponds to different manufacturing technology and materials set. The dark blue curves correspond to the old Gl-Poly designs, then the greens to Gl-Epoxy etc. The overall trend yields an up-scaling weight exponent of 2.5 but there are other studies indicating that this number might be closer to 2. Note that the weight reduction of the most recent technologies is associated to the increasing use of carbon fiber in spar-beams construction. In this case weight reduction is not directly translated to cost reduction due to the higher costs of carbon compared to glass.

Turbine top-head-mass evolution trends for multi-MW designs of different drive train technology are discussed in [7]. The overall trend yields an up-scaling exponent close to 2.2-2.3 for all architectures of present interest (traditional high-speed gearbox, permanent magnet medium speed and direct drive and electromagnetic direct drive). We anticipate that the trend will be maintained in the larger turbine sizes of our interest, possibly with the development of alternative drive train technologies such as the superconductive or the pseudo magnetic direct drive concepts currently under study in Innwind.EU.

Regarding the support structure let us distinguish between the turbine tower (from tower-top to the zero mean-sea-level), transition piece and the offshore foundation part (from the zero mean-sea-level to the sea bottom). To be more relevant, we should have set the interface at the transition piece level instead of the zero mean-sea-level but this is not important for our conceptual discussion.

Using a simplified tower model scaled linearly in all three dimensions and optimizing the tower mass for buckling resistance under ultimate loading (following DIN 18800 on Structural Steelwork) it has been shown in [5] that the resulting weight scaling exponent is λ_w=3+. However, in offshore designs the standard practice is to fix the blade – mean sea level clearance than scaling linearly the hub height. Repeating the design exercise of [5] with a fixed blade–mean sea level clearance$(\mathrm{h_{clear}})$, where the up-scaled tower is expressed as $\mathrm{H(s) = s.\frac{D_1}{2} + h_{clear}}$ instead of $\mathrm{H(s) = s.H_1}$ (with D1, H1 being the diameter and hub-height of the initial design (s=1)) the resulting scaling exponent of the optimized tower mass is now $\lambda_w \cong$ 2.7.

For the offshore foundation system we can work in a similar way assuming a fixed height (equal to the water-depth) and a tubular structure (strictly valid for monopiles only). In this case the resulting scaling exponent of the optimized mass is $\lambda \cong$ 1.7. This is an interesting outcome which is valid for both monopiles and jackets when the water depth is fixed.

The assumption of the proportionality between the mass and the cost scaling will be altered as soon as we have validated cost models for the different turbine subcomponents and cost categories. At the moment we use the cost /mass proportionality for deriving the above target values in a physically meaningful way.

5 Other Important LCOE Drivers

We have identified the turbine and BoP CAPEX, the wind farm capacity factor and the O&M annual costs as important drivers of LCOE. We are now questioning whether we can identify specific turbine design parameters which have a significant influence to the LCOE drivers and the turbine and BoP CAPEX in particular. So far we have identified three candidates for which we have done preliminary investigations regarding their down-stream influence. These are: a) the rotational speed, b) the tower-top mass and c) the design thrust of the rotor. Table 2 presents the sensitivity of the rotor, nacelle, tower and offshore foundation (OF) mass (and in most of the cases cost) to these design parameters in terms of weight up-scaling exponents (going from 5 MW to 10 MW).

Regarding the rotational speed it is clear that its increase reduces the gearing ratio (and therefore the drive train efficiency) but also the drive train torque and therefore the drive train weight and cost. Moreover, increasing the rotor tip-speed ratio (through the rotational speed) may result in a better Cp-max value and this combined with the drive train efficiency might add one to two percentage units to the wind farm capacity factor. In Table 2 we also investigate the influence of the rotational speed to the nacelle mass. Up-scaling from 5 to 10 MW in the classical sense that would imply a λ value for the rotational speed equal to -1 (since the tip-speed remains the same) and a nacelle mass up-scaling exponent equal to 3 (λ-from value). A 20% increase of the rotational speed (λ = -0.80) yields a reduced value for λ (λ-to) equal to 2.80. We do not discuss the rotational speed sensitivity to the rotor cost further since this is a much more complicated issue. Reducing the nacelle mass (through the increase of the rotational speed) has a downstream influence to the tower and offshore foundation that will be studied below.

Regarding the downstream influence of the nacelle mass (reduction for any possible reason) we see in Table 2 that a very drastic reduction from λ=3 (classical up scaling) to λ=2.30 (using a much lighter drive train concept, for instance) does not have an equally important effect on tower and

Table 2: λ – sensitivity to other turbine design parameters

			Rotor Mass		Nacelle Mass		Tower Mass		OF Mass	
	λ_from	λ_to	λ_from	λ_to	λ_from	λ_to	λ_from	λ_to	λ_from	λ_to
Rotational Speed	-1,00	-0,80	?	?	3,00	2,80				
Tower-Top Mass	3,00	2,30					2,70	2,65	1,70	1,66
Max Design Thrust	2,00	1,60	?	?	?	?	2,70	2,46	1,70	1,53

foundation masses. This may be expected since tower top weight has a relatively small contribution to the tower and fixed foundation design stresses. Thus, for bottom-mounted offshore designs, the reduction of the tower-head mass, if not followed by an associated cost reduction (for the rotor or the drive train) or an increase of the turbine capacity factor, is not a target by itself and it can by no means pursued at the cost of drive train efficiency. This statement is not valid for floating designs where the tower-head mass might be an important driver of the cost of the floater.

Contrary to tower-head mass, the sensitivity of the overall support structure mass to the maximum (design) thrust is significant. The 2.70 exponent for the tower mass and the 1.70 for the offshore foundation (corresponding to classical turbine up scaling but with fixed blade-water clearance and fixed water depth) are now diving at 2.46 and 1.53 for a thrust λ drop from 2 (aerodynamic similarity in classical up scaling) to 1.60. This is a very important effect and should be one of the areas where innovation should be pursued.

It should be noted once more that all conclusions for tower and offshore foundation up scaling are based on ultimate loading considerations and we completely miss fatigue design in our analysis. Nevertheless, we believe that the conclusions extracted with this “high level” approach are still valuable although they still need to be confirmed with more detailed methods.

6 Conclusions

A 20% LCOE drop from present values until 2020 seems quite feasible for deep offshore wind farms if relevant innovative designs are implemented at Large (10 MW+) scales.

For fixed water depth, the optimum sizing of the turbine derives by balancing the extra turbine cost with the lower BoP cost per MW as the turbine size increases. This is a common conclusion in all offshore cost studies. It appears that as the water depth increases larger turbines will be the optimum bottom-fixed solution. Nevertheless, this optimum size is still very much dependent on how successful are the implementation of the new lower cost technologies in turbine and offshore substructure designs.

Significant LCOE reduction and IRR improvements can be expected by improving the wind farm capacity factor. This can be done by using larger turbines with low induction (low-thrust) rotors for better aerodynamic performance and by improving the efficiency of the drive train, power electronics and array cables. These innovations may also require lesser subsidies for offshore wind power generation.

Coming to the downstream influence of the nacelle mass we have seen that even a very drastic reduction does not have an equally important effect on tower and foundation masses for bottom-mounted designs. This is somehow expected since the compressive load associated to the tower-head mass has a relatively small contribution to the tower and foundation design stresses. Thus, for bottom-mounted offshore designs, the reduction of the tower-head mass if not followed by an associated cost reduction (rotor or drive train) or an increase of the turbine capacity factor is not a target by itself and it can by no means pursued at the cost of drive train efficiency. This statement is not valid for floating designs where the tower-head mass might be an important driver of the cost of the floater.

Contrary to tower-head mass, the sensitivity of the overall support structure mass to the maximum (design) thrust is significant. This is a very important effect and should be one of the areas where innovation should be further pursued. The concept of low-induction rotors is also a promising option for design thrust reduction.

Acknowledgements

The research leading to these results has received funding from the European Community’s Seventh Framework Programme under grant agreement No. 308974 (Innwind.EU)." The support is gratefully acknowledged.

References

[1] Key Performance Indicators for the European Wind Industrial Initiative, SETIS-TPWIND, Version: 3, 7th November 2011

[2] G. Sieros, P. Chaviaropoulos, J.D. Sorensen, B.H. Bulder, P. Jamieson. Up-scaling Wind

Turbines: Theoretical and practical aspects and their impact on the cost of energy. Wind Energy 2012. 15(1): 3-17
[3] Giguere, P., Selig, M.S. Blade Geometry Optimization for the Design of Wind Turbine Rotors. Proceedings of AIAA/ASME Wind Energy Symposium. Reno, NV, (January 10-13, 2000).
[4] The Crown Estate, Offshore wind cost reductions pathways study, May 2012.
[5] G. Sieros, P.K. Chaviaropoulos. Aspects of up-scaling beyond similarity. Proceedings of 'The Science of Making Torque from Wind' Conference, Heraklion, Greece, 28-30/6/2010, Edited by S. Voutsinas and P. K. Chaviaropoulos.
[6] P.K. Chaviaropoulos; H.J.M. Beurskens and S. Voutsinas, Moving towards large(r) high speed rotors – is that a good idea? Proc. Scientific Track, EWEA 2013 Conference, Vienna.
[7] BTM Consultants, World Market Update 2011, http://www.btm.dk/reports/world+market+update+2011
[8] LCICG, Technology Innovation Needs Assessment (TINA), Offshore Wind Power, Summary Report, February 2012
[9] Renewable UK, Offshore Wind, Forecasts of future costs and benefits, www.RenewableUK.com, June 2011
[10] The Economics of Wind Energy, EWEA Report, Soeren Krohn (editor), March 2009
[11] Peter Jamieson, Innovation in Wind Turbine Design, A John Wiley & Sons, Ltd., Publication, ISBN 978-0-470-69981-2, 2011
[12] L. Fingersh, M. Hand, and A. Laxson. Wind Turbine Design Cost and Scaling Model, NREL/TP-500-40566, December 2006
[13] E. S. Politis and P. K. Chaviaropoulos, "Micrositing and Classification of Wind Turbines in Complex Terrain," Proceedings of the 2008 European Wind Energy Conference & Exhibition, Brussels, 31/3-3/4/2008, Edited by P. K. Chaviaropoulos, pp. 126-130.