Deliverable 1.2.2

Definition of Performance Indicators (PIs) and Target Values

February 2014

Agreement n.:	**308974**
Duration	Nov 2012-Oct 2017
Co-ordinator:	Peter Hjuler Jensen, DTU

Support by:

Document information

Document Name:	**Definition of Performance Indicators (PIs) and Target Values**
Document Number:	**Deliverable D1.2.2** **Dissemination Level PU**
Author:	**Panagiotis Chaviaropoulos and Anand Natarajan**
Review:	**Fragiskos Mouzakis**
Date:	**February 2014**
WP:	**WP1: Conceptual Design**
Task:	**Task 1.2: Assessment of Innovation at the Subsystem Level**

TABLE OF CONTENTS

INTRODUCTION

1.1. Scope and Objectives

In this document we define the Performance Indicators that will be used in the Innwind.EU project for assessing innovative designs at the components and at the system's level.

The performance indicators are cost driven and will evaluate the:

- Effect on energy yield (increased performance)
- Direct effect on Levelised Cost of Electricity (LCOE) and customer value of the turbine
- Indirect effect on downstream components (loads, weight)

The selection of PIs will take account and build upon the earlier work on Key Performance Indicators done in the EWI framework [1]. The LCOE for the reference wind turbine will be used as a basis for comparison using available cost data combined with up-scaling laws.

Based on the impact of the performance of various components on that, target values for the subcomponents will be set with the purpose of satisfying the overall performance improvement that is required.

KEY PERFORMANCE INDICATORS

2.1 KPIs for the European Wind Industrial Initiative (EWII)

EWII introduced a single overarching KPI in order to monitor the impact of the Wind Energy Roadmap (2010-2020) on the sector. This overarching KPI is the Levelised Cost of Electricity (LCOE) produced by wind power, and it is expressed in Euro per Megawatt-hour (€/MWh).

The LCOE represents the sum of all costs over the lifetime of a given wind project, discounted to the present time, and levelized based on annual energy production. Furthermore, the LCOE can be calculated with a number of different methods or approaches to represent several differing perspectives. A simplified version for LCOE is used here, the details of which are presented in [1] along with the assumptions and parameters needed to establish its present reference values for both onshore and offshore wind energy.

The literature describes country specific variations, but the reference values used herein are reflecting adequately European-wide best-practice averages. The discount rate used is based on cost of capital and the period required to break even in the wind farm project. The system in which the reference cases are to apply must be clearly defined by delimiting which aspects are within the system boundaries and which are not. Following [1], our assumptions are that permitting costs, connection from the wind farm substation to the external grid, civil works outside the wind farm, financing costs, overheads and decommissioning costs are outside our system boundary. Other parameters necessary for the calculation of the LCOE are listed in Table 1 below along with their consented value.

Table 1. *Reference case values for the LCOE in EWII [1]*

PARAMETERS	ONSHORE	OFFSHORE
Capital investment cost – CAPEX (€/kW)	1 250	3 500
O&M costs including insurance(€/kW/yr)	47	106
Balancing costs (€/MWh)	3	3
Capacity factor (%)	25	40
Project lifetime (years)	20	25
Real discount rate (%)	5,39	5,39
Total plant capacity (MW)	40	300
Size of wind turbines (MW)	2.5	5-7

For Innwind.EU the focus is on the cost-effectiveness of large offshore turbines. Therefore, in the present context we shall further focus on the CAPEX and the size of the wind turbine.

Offshore CAPEX has been also discussed in [1]: "*The offshore figure initially proposed (2500 €/kW) was considered too low by Member States (EWI Team meeting), consultants, and the industry. Mott MacDonald ([MML, 2011]) gives a figure of GBP 3 088/kW (€3 551/kW @ 1,15 EUR/GBP), and in a personal communication (Mr John Porter) considered values around €3 000/kW valid for the UK context, around €4 000/kW for German wind farms farther away/deeper waters. Turbine manufacturers suggested figures of €3 000-3 500/kW in the UK and € 4 000 for Germany. ARUP's [2011] estimates a median cost of GBP 2 722-2 825/kW (€3 130-3 250/kW @ 1,15 EUR/GBP) for current large offshore wind farms/Round 3 projects.*"

Evidently, the CAPEX of 3 500 €/kW is a consented "mean value" and is rather low as a starting point for Innwind.EU that targets sea water depths of 50 m and above. The figure 3 500 €/kW is representative for one of the largest in the world offshore projects that started producing electricity in April 2013, the London Array (phase I) [2]. This is a 630 MW project (total investment €2.2 billion) comprising 175 SIEMENS 3.6 MW turbines, on monopiles, at sea depths less than 25

m. There are two substations offshore collecting the electricity from the turbines with 210 km 33 kV array cables. The electricity is then transferred onshore with a 220 km (4 X 55 km distance) 150 kV subsea export cable. Clearly, the 3 500 €/kW figure corresponds to a very large wind farm, not too far from the coast and to water depths rather shallow compared to the Innwind.EU specifications. Also, this CAPEX figure includes elements (like the export cable and the onshore substation) which stand outside our system boundary.

Table 2 shows the results of EWII-LCOE calculations assuming a linear reduction of the LCOE from 2010 to 2020 that reaches 20 % by 2020. These figures are the result of EWEA's cost model updated and adapted as described above.

Table 2. ***LCOE values and targeted evolution***

LCOE evolution	ONSHORE		OFFSHORE	
	Abs.	Rel.	Abs.	Rel.
LCOE by 2010 (€/MWh)	71,80	100	106,93	100
LCOE by 2015 (€/MWh) (-10%)	64,43	90	95,57	89
LCOE by 2020 (€/MWh) (-20%)	57,15	80	84,77	79

A first remark is that the resulting offshore reference LCOE (named "LCOE by 2010") of 106,93 €/MWh is extremely low. There are several publications and press releases by major offshore wind farm developers and operators such as DONG [3] and E.ON [4] stating that they aim to cut the cost of wind energy in the North Sea to less than 100 or even 90 €/MWh by 2020 compared with the 160 €/MWh last year (2012). The 2012 figure most likely addresses the experience gained from the London Array project co-owned by these two companies and Masdar. Evidently the 160 €/MWh figure is not directly comparable to our 106,93 €/MWh LCOE since it includes all costs, a good part of them standing outside our system boundaries. It is interesting to note that in order to get this 60% cost reduction Dong has plans [3] to radically increase the size of the offshore turbines it will install, from 3 to 4 megawatts currently to 8 to 10 MW in 2016 through 2020.

To appreciate the difference between our reference value of LCOE 106,93 €/MWh and the cost of energy of 160 €/MWh we present in Fig 1 a parametric study of the EWII-LCOE in terms of the CAPEX and the net capacity factor of the wind farm. This is done using the input data of Table 1 fixing OPEX at 106 €/kW/yr. Clearly, the distance of 53 (160-107) €/MWh cannot be attributed to the assumed rather low capacity factor of this wind farm (there are only estimations in the literature ranging from 0.29 to 0.35 but no official value given yet from the London Array wind farm operators). Part of this difference is attributed to costs such as project development, financing and overheads, which are not included in our model. The rest is attributed to increased, more realistic, O&M costs. As an example, we refer to a recent study of RolandBerger [5] where the current O&M cost for a typical offshore wind farm of today is taken at 140 €/kW/yr (significantly more than our 106 €/kW/yr assumption). High LCOE values of 140 £/MWh are also reported by the Crown Estate [7] for projects at final investment decision in 2011. This LCOE includes in its CAPEX development, project management and decommissioning costs while transmission charges and seabed rent are accounted in its OPEX. In addition, the discount rate is set at 10% compared to the 5,2% value used in EWII-LCOE, burdening the cost of energy significantly.

Figure 1 is quite instructive for evaluating the sensitivity of LCOE to its main drivers CAPEX and CF. It is seen that in the area of our interest increasing CF from 0.40 to 0.45 leads to a reduction of LCOE by 10 €/MWh which is equivalent to the reduction resulting from cutting the CAPEX down by 500 €/kW. On the same figure we present as a window plot the range of CAPEX and CF values which correspond to the reference and target values of Table 2.

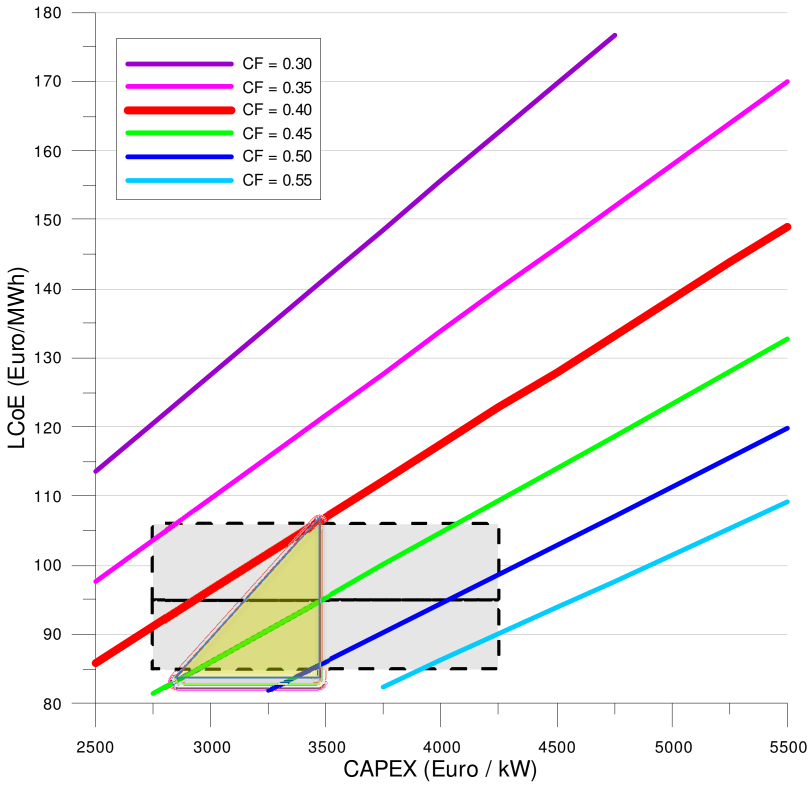

Figure 1 *LCOE dependence on CAPEX and Capacity Factor for fixed OPEX 106 (€/kW/yr)*

The cost figures that we discussed above are referring to bottom-mounted turbines at water depths that are currently exploited, that is less than 25-35 meters. At water depths of Innwind.EU interest, in the range of 50 m, the assumed CAPEX and consequently the starting value of the levelised cost of electricity (106,93 €/MWh) are rather low, rendering the 2020 target figure of 84,77 €/MWh quite challenging for the project. Clearly, such drastic cost reduction can be only obtained by significantly improving all LCOE drivers, CAPEX, CF and OPEX.

For consistency in our analysis we have to set a time reference to all currencies. Whenever we refer to costs in this report that would be in € (2012).

2.2 Calculating LCOE for the reference case

Using the parameters of Table 1 a LCOE calculator is programmed in Microsoft XL and distributed to the project partners. For addressing the project needs 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) is now split in **Turbine Cost** (1 500 €/kW) and **BoP Cost** (2000 €/kW).

Although at this stage it is the total CAPEX and not its split in turbine and BoP costs that counts, we shall briefly discuss the split issue, preparing the fore coming sections. 1 500 €/kW is a rough estimate of the cost of a 5 MW machine, which is based on recent publications [5], [6], [7] summarized in Table 3. Note that:

- Referring to Table 1 we are more confident for the 3-4 MW turbine costs (than the 6 MW) since 3-4 MW is the size used in the most recent commercial projects.

- Table 1 refers to projects for SITES A and B according to the Crown Estate classification [7]. These are sites with water depths less than 35 m (SITE B) with construction and operation ports at distances less than 40 km.
- In the Crown Estate classification, the tower is part of the foundation cost. In [5] and [6] the tower belongs to the turbine cost.
- The Crown Estate numbers are approximate (estimated from figures and not taken from tables) and have been calculated with 1 £/ € (2012) = 1,24.
- In the R&B [5] 3MW CAPEX the “Other” costs are outside our system’s boundary and they are not counted in the SUM.

Table 3. *CAPEX Split with turbine size*

		Roland Berger [5]		Ref [6]	Crown Estate- SITE B [7]	
		3MW Turbine	6MW Turbine	6MW Turbine	4 MW Turbine	8 MW Turbine
CAPEX SPLIT (M€ /MW)	*Turbine*	1,35	1,55	1,45 - 1,60	1,26	1,55
	Foundation	0,96			0,84	0,74
	Installation	0,62			0,71	0,36
	Electrics	0,58				
	Other	0,39			0,65	0,65
	SUM	3,51			3,46	3,30

LCOE CALCULATOR		*ONSHORE WIND* EWII	*OFFSHORE WIND* EWII
Total Plant Capacity (MW)	P	40,00	300,00
Size of Wind Turbines (MW)	Pt	2,50	5,00
Turbines Cost (€/kW)	Ct	900	**1.500**
BoP Cost (€/kW)	Cb	350	**2.000**
Capital Investment Cost (€/kW)	C	1.250	3.500
O&M Costs (€/kW/y)	O&MF	47	106
O&M Costs [incl. fixed annual costs, (€/MWh)]	O&M	21,46	30,25
Balancing Costs (€/MWh)	BC	3,00	3,00
Project Lifetime (y)	N	20	25
Capacity Factor (%)	Cf	0,25	0,40
Nominal Discount Rate (%)	dn	0,07	0,07
Inflation Rate (%)	i	0,02	0,02
Real Discount Rate (%)	d	0,0539	0,0539
Capital Recovery Factor (%)	CRF	0,083	0,074
Summation of Discounted Future Expend	SFE	12,058	13,557
Present Value of Total O&M (€)	SO&M	25.838.573	473.853.240
Annual Energy Production (MWh/y)	E	87.600	1.051.200
Levelized Investment (€/y)	LI	4.146.514	77.452.842
AnnualLDiscounted O&M (€/y)	DO&M	2.142.800	34.953.600
Annual O&M / Capital Investment (%)	O&M(%)	0,038	0,030
	LI/E	47,33	73,68
	DO&M/E	24,46	33,25
LCOE (€/MWh)		**71,80**	**106,93**
Contribution of CAPEX (Turbines) (€/MWh)		34,08	31,58
Contribution of CAPEX (BoP) (€/MWh)		13,25	42,10
Contribution of OPEX (€/MWh)		24,46	33,25
Contribution of CAPEX (Turbines) (%)		0,47	0,30
Contribution of CAPEX (BoP) (%)		0,18	0,39
Contribution of OPEX (%)		0,34	0,31
		1,00	*1,00*

Figure 2 *Validation of the LCOE Calculator*

A snapshot of the LCOE calculator is shown in Figure 2. The notation of [1] is used for all variables. The calculation reproduces the correct LCOE value for the reference onshore and offshore cases of Table 1. In addition it yields its splitting to the three main cost components (CAPEX Turbine 30%, CAPEX BoP 39% and OPEX 31%).

Further, one can evaluate the contribution of any individual wind turbine subcomponent to the levelised cost of electricity as soon as the percentage of its contribution to the wind turbine CAPEX is known. To the authors knowledge there are at least three publications (EWEA [10], Peter Jamieson [11] and the WindPACT Study [12]) that provide the above contributions for 3-5 MW wind turbines.

Adopting the EWEA percentages (originating from Wind Directions, Jan/Feb 2007) according to Table 3 and the BoP split of Table 4 (following the 3MW split of ref [5], but also the 4MW split of ref [7]), the contribution of the wind turbine subcomponents and the BoP subcategories to the LCOE is straight-forward.

The actual values used in Tables 3 and 4 will be revised, if necessary, after consultation with the industrial partners of the project and will be harmonized with the cost models which will be developed in the companion ***Deliverable 1.2.3: PI-based assessment of innovative concepts.***

The resulting contributions as percentages of LCOE are presented in Table 6.

Table 4. *Subcomponents' contribution to Turbine CAPEX (5 MW HAWT)*

Turbine	**Rotor**	*Rotor lock*		**0,2357**	**1,00**
		Blades	**0,2220**		
		Hub	**0,0137**		
	Nacelle systems	*Gearbox*	**0,1291**	**0,2979**	
		Generator	**0,0703**		
		Rotor brake	**0,0132**		
		Nacelle cover	**0,0135**		
		Nacelle structure	**0,0280**		
		Couplings			
		Shaft	**0,0191**		
		Yaw system	**0,0125**		
		Bearings	**0,0122**		
	Electrics & control	*Pitch system*	**0,0266**	**0,0767**	
		Variable speed sys	**0,0501**		
	Tower			**0,2630**	
	Other			**0,1300**	

Table 5. *Split of BoP CAPEX to its subcategories (5 MW HAWT)*

BoP Only		*Foundation system*	**0,4400**		**1,00**
		Offshore transportation & installation	**0,3000**		
		Offshore electrical I&C	**0,2600**		

Table 6. *Subcomponents' contribution to LCOE*

OFFSHORE	**CAPEX**	**Turbine**	**Rotor**	*Rotor lock*	0,0000	0,0696	**0,30**	**0,69**
				Blades	0,0656			
				Hub	0,0040			
			Nacelle systems	*Gearbox*	0,0381	0,0880		
				Generator	0,0208			
				Rotor brake	0,0039			
				Nacelle cover	0,0040			
				Nacelle structure	0,0083			
				Couplings	0,0000			
				Shaft	0,0056			
				Yaw system	0,0037			
				Bearings	0,0036			
			Electrics & control	*Pitch system*	0,0079	0,0226		
				Variable speed sys	0,0148			
			Tower			0,0777		
			Other			0,0384		
		BoP		*Foundation system*	0,1732		**0,39**	
				Offshore transportation and installation	0,1181			
				Offshore electrical I&C	0,1024			
	OPEX	**O&M Offshore**					**0,31**	**0,31**

Note that in this particular example the rotor's share in LCOE is only 6,9%. This implies that using a more expensive rotor which will substantially increase the annual energy production but keep the same support structure might be beneficial for the cost of wind energy offshore. On the other hand, the largest contribution to LCOE is that of the offshore foundation system (17%).

2.3 Calculating LCOE for Up-scaled Designs

Next, we shall calculate the LCOE of up-scaled designs. To demonstrate the concepts we shall work with two up-scaling strategies, first with "classical up-scaling" (using same technology) and second with "innovation-based up-scaling", which implies the adoption of new technologies with a strong potential for cutting the costs (and weight) down but also for increasing the offshore wind farm capacity factor. The goal at this stage is not to identify these innovative technologies but to set targets on their desirable performance. These targets will be detailed later in this document in terms of up-scaling coefficients at the components' cost level.

2.3.1 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. This effect was studied in the UPWIND Project [13] where the (aerodynamic) wind farm capacity factor was calculated as a function of the WT rated power. The mean wind speed distribution used at the hub height of all designs was a Rayleigh with mean 10 m/s while the wind rose was assumed uniform direction-wise. Two wind farm sizes were considered with 500 and 1000 MW installed capacity. Calculations have been performed with the CRES-Farm engineering model [14]. The starting 5 MW turbine was the Upwind Reference Turbine and classical up-scaling (same Cp-Wind speed curve) was assumed for the 10 to 20 MW turbine sizes. The spacing of the turbines was 7D X 7D leading to similar offshore area requirements for all turbine sizes.

It is seen in figure 3 that the wind farm aerodynamic capacity factor (the production of all turbines including the wake effects) is increasing with the size of the single turbine. Going from 5 to 10 MW we have a nearly linear increase of nearly 2,5 percentage units with an additional increase of 2,5 units from 10 to 20 MW. This effect is attributed to the reduction of wake effects due to the smaller number of turbines in the wind farm when the rated power of the individuals increases. We note that this capacity factor improvement is not related to better wind resource going at larger distances from the shore (and deeper waters) or going at larger hub heights. These are additional factors that might further increase the farm capacity and are (indirectly) linked to the single turbine size. Other factors that can further increase the wind farm capacity factor are the development of advanced optimization tools for designing large offshore wind farms and the increase of the voltage level of the array grid.

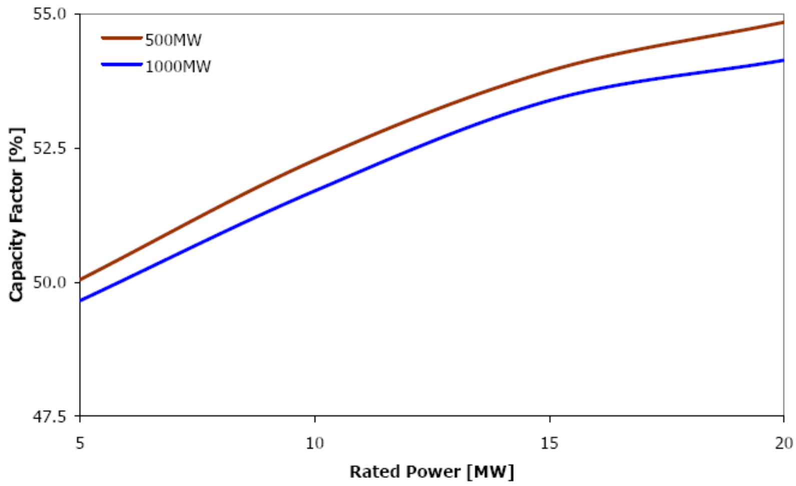

Figure 3 *Effect of turbine size on the aerodynamic capacity factor of large offshore wind farms.*

Further, we have shown in [15] that innovative rotor design, such as low-induction / low-thrust rotors of increased swept area may produce more power with the same turbine loading.

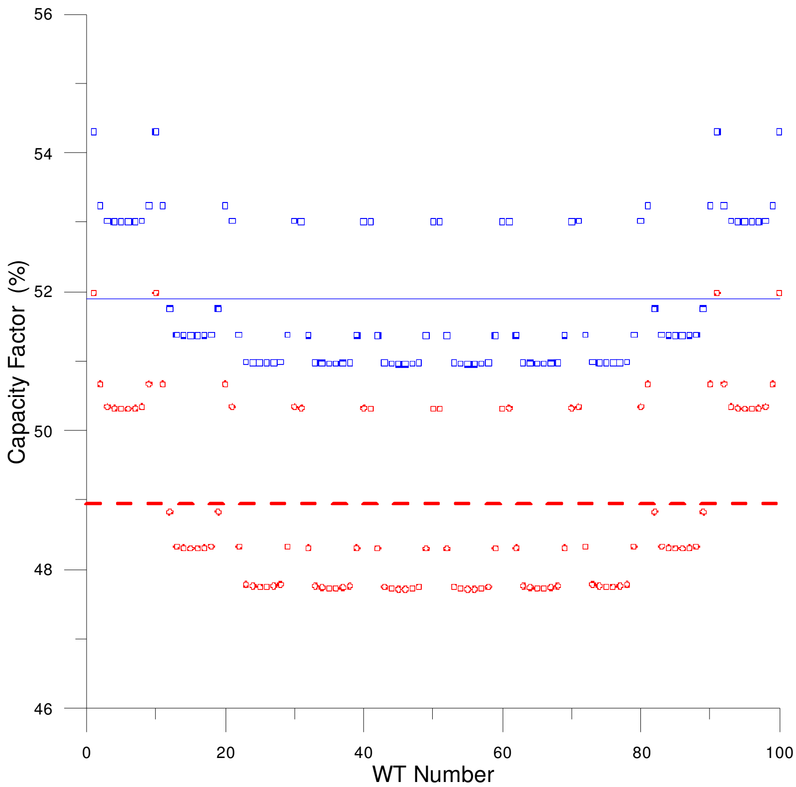

Figure 4 *Capacity factor and wake losses per turbine in a 10X10 offshore wind farm with 5 MW turbines at 8D spacing. Red dots refer to the initial turbines ("standard", highly loaded) and blue squares to the less loaded ("low-induction") turbines. The dashed red and the blue line correspond to the wind farm mean values.*

Figure 4 presents the capacity factor of all 100 turbines in a 10X10 offshore wind farm of 5 MW "standard" and alternatively "low-induction" turbines. Calculations are performed with CRES' in-house wind farm analysis tool CRES-Farm [14]. It is seen that by using the less loaded – larger diameter – turbines, the wind farm capacity factor increases by nearly 3 percentage units (from 49% to 52%). Looking carefully to this 3% half of it comes from 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, therefore, thrust coefficients of the larger rotors. We have also seen (not presented here) that this percentage gain in annual energy production is more or less flat and independent of the turbine spacing.

Assuming that the turbine size effect and the innovative design effect on wind farm capacity factor can be superimposed as independent factors we shall claim that the net capacity factor of a large offshore wind farm can increase by 3 percentage units for a standard design and by 7 percentage units for an innovative design when the turbine size is increased from 5 to 10 MW. This net capacity factor is obtained by subtracting from the aerodynamic capacity factor all electrical losses (up to the transmission grid connection point) taking also account of the turbines availability.

2.3.2 Effect of up-scaling on OPEX

Increasing the turbine size reduces the OPEX per installed MW. Evidently, the OPEX part which is simply proportional to the number of turbines in the farm is getting down when larger turbines are used. Further OPEX reduction can be expected from innovative operation and maintenance schemes. RolandBerger [5] assumes a 14% reduction of annual OPEX cost only by shifting from the 3 MW to the 6 MW turbines. The Crown Estate [7] estimates in a similar study a reduction of 10-15%. We shall not research deeper the OPEX contribution in this environment but we shall assume that a 10% reduction for the standard practices and a 20% reduction with innovative practices is feasible, following the turbine size increase from 5 to 10 MW.

2.3.3 Effect of up-scaling on CAPEX

In classical up-scaling we assume that the scaling exponent for CAPEX is λ_c=3 for the turbine and its main subcomponents [16], [17] and λ_c=2 for the BoP part. Namely, the Turbine CAPEX scales-up with s^3 where s is the linear scale factor (defined with the assumption that rated power scales-up with s^2) . For the turbine part we have shown in the referred papers that the <u>weight</u> of the main components (blades, low-speed shaft, gearbox, tower) scales-up with λ_w=3+ε (ε<<1), for any given technology, so the assumption that the <u>cost</u> scales-up with λ_c=3 is fair when mass is the main cost driver (subscripts *c* and *w* stand for cost and weight). Our assumption for the BoP scaling exponent needs further discussion. Upwind [18] 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.). From these categories, Innwind.EU is only addressing the offshore foundation system, so we shall restrict our discussion to that. For a given water-depth (which is the case here) it is logical to assume that the offshore foundation system (jacket but this applies to monopiles as well) weight is scaling-up in two dimensions and not in three (since it is constrained by the fixed water-depth), thus λ_w=2. We assume that this is also valid for the cost of the foundation system, although weight is not always the prevailing cost drives. For jackets, for instance, costs are mainly driven by requirements for fabrication (batch processes with much of the welding done manually) and installation. This results in high proportions of tooling and labor costs (2/3 of total according to [7]) which, again, can be assumed to scale closer to λ_c=2 than λ_c=3 given the fixed height. Figure 5 presents LCOE results for classical and innovation-based up-scaling. Starting from a reference 5 MW turbine we first up-scale it in the classical sense to 10 MW (column "Classical Up-scale 10 MW"). For the CAPEX entries we used the scaling coefficients λ_c=3 and λ_c=2 as discussed above. For OPEX we assumed a 10% drop of the O&M costs due to the larger turbine size, as discussed earlier in section 2.3.2. Even so, the LCOE increases moderately from 106,93 €/MWh to 109,19 €/MWh suggesting that going to larger machines with today's technology is not a cost effective option. Notably the increase of LCOE is coming from the turbine itself while the BoP CAPEX per kW remains the same (as the cost scales with λ_c=2, i.e. with the rated power of the turbine).

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 5 *LCOE Calculation for classical and innovation-based up-scaling*

The next columns of figure 5 present LCOE results for "innovation-based up-scaling", going from the 5MW to 10, and then up to 20 MW. We shall first elaborate on the "Innovative 10 MW" design which is the Innwind.EU focus. Note that our analysis does not include any maturity costs of the new / innovative technology against the standard /classical one assuming similar learning curve advancements. As discussed in sections 2.3.1 and 2.3.2 we now assume a capacity factor increase by 7 percentage units (from 40% to 47%) and an OPEX drop of the order 20%. For the CAPEX up-scaling we now use scaling coefficients λ_c<3 and λ_c<2. Evidently, the exact scaling values (in this example 2,42 and 1,50 referring to the 5 MW design) are overall numbers that depend on the progress that we can demonstrate at the different cost subcategories. How realistic and ambitious these numbers are will be discussed in the next section. Nevertheless, this set-up is good enough for achieving the target LCOE of 85 €/MWh which is the 2020 EWII-LCOE target of Table 2.

It should be noted that the differentiation of λ_c from its classical value (λ_{clas}=3 for the turbine) is only attributed to technology improvement. To demonstrate that we assume a scaling-up from 1 to s (for the rotor, for instance, we up-scale from a diameter D to s*D) improving at the same time the technology from T_1 to T_s. Then, the following relations are valid for the CAPEX (C) of any subcomponent:

$$\frac{C(s,T_s)}{C(1,T_1)} = \frac{C(s,T_s)}{C(s,T_1)} \cdot \frac{C(s,T_1)}{C(1,T_1)} = r.s^{\lambda_{clas}} \quad \text{but} \qquad (1)$$

$$\frac{C(s,T_s)}{C(1,T_1)} = s^{\lambda_c} \quad \text{so,} \qquad (2)$$

$$s^{\lambda_c} = r.s^{\lambda_{clas}} => s^{\lambda_{clas}-\lambda_c} = \frac{1}{r} => (\lambda_{clas} - \lambda_c)ln[s] = -ln[r] \qquad (3)$$

The first equation states that the cost ratio of (up-scaled component built with the new technology) by (initial scale build with existing technology) is equal to the product of:

- the cost ratio of (up-scaled component built with new technology) by (up-scaled built with existing technology) – we call that (*r*) – with
- the cost ratio of (up-scaled component) by (initial scale component) both built with existing technology) =s $^{\lambda clas}$ by definition of the classical up-scaling

The second equation is straightforward from the definition of λ_c, while the third quantifies the relation between *r* and λ for a given s. These ideas are visualized in figure 6.

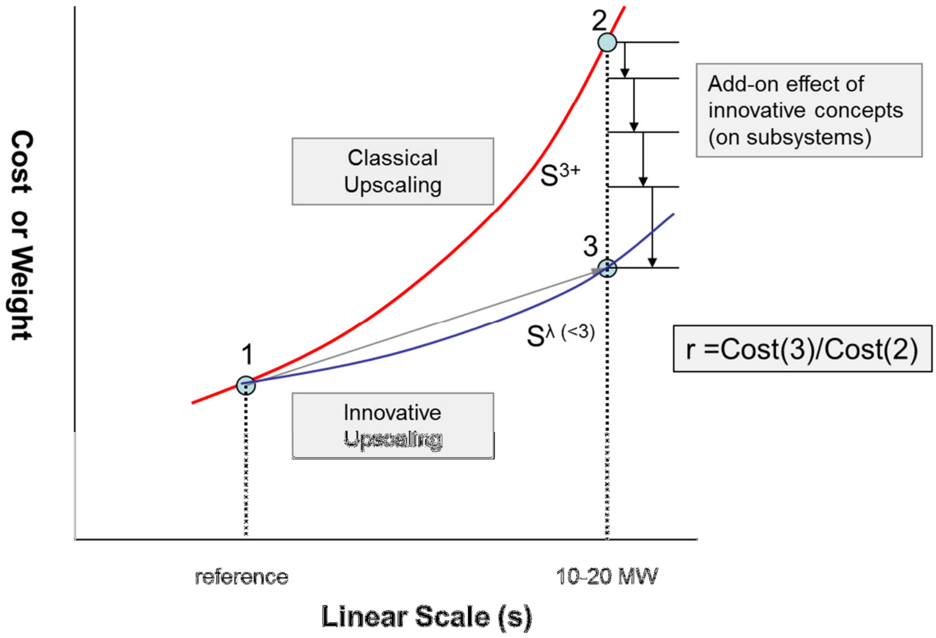

Figure 6 *Scaling exponent λ and cost ratio*

An application example of equation (3) is now given. Up-scaling the rated power from 5 MW to 10 MW the rotor diameter increases by $\sqrt{\frac{10}{5}}$ (thus, s=1,41) and the desired reduction of λ_c from 3 to 2,42 (following figure 3) requires a new technology able to reduce the turbine cost (at a given size) by 18% (*r*=0,82) compared to the conventional technology. This can be also verified by comparing the 10 MW single turbine costs of figures 5 ("Innovative 10 MW" by "Classical Upscale 10 MW").

Going back to figure 5 we shall now comment on the 15 and 20 MW up-scaled designs. The LCOE in these cases has been calculated assuming minor technological improvement compared to the 10 MW innovative design. This can be seen from the assumed turbine scaling exponents (2,80 and 2,90 referring to the 10 MW Innovative design this time). On the contrary, the BoP CAPEX scaling exponent is still kept at 1,50 thanks to the fixed sea depth and some cost improvement due to innovation.

For the innovative designs derived with the above "overall" λ_c values the LCOE corresponding to the 5, 10, 15 and 20 MW turbines is 106,93 €/MWh, 85,18 €/MWh, 84,75 €/MWh and 85,77 €/MWh. Under our assumption there appears a shallow LCOE minimum at the 15 MW turbine size but this is not a meaningful conclusion as the actual optimal size is a question of the exact cost values. More interesting is the way that LCOE is now distributed to its Turbine and BoP components. Since the turbine λ_c is still larger than 2 but the BoP λ_c is now smaller that 2 (2 corresponding to the scaling of the rated power), the contribution of the BoP in LCOE is dropping as the turbine rated power increases along with the contribution of the turbine CAPEX. Thus, for fixed water depth, the optimal 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 that we are aware off (see for instance [5], [7], [8] and [9]). It looks that as the water depth increases larger turbines will be the optimum solution. Nevertheless, this optimum size is still very much dependent on how successful we'll be in implementing new lower cost technologies in turbine and offshore substructure designs.

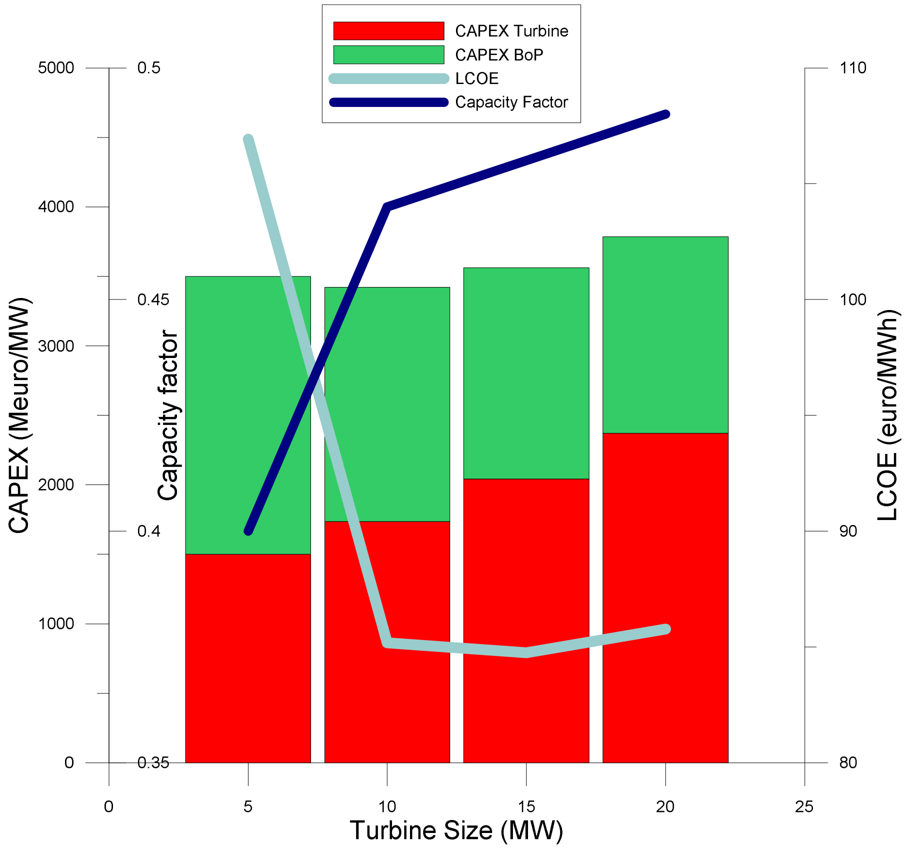

Figure 7 *Turbine size influence to LCOE and its main drivers*

The main findings of figure 5 and the discussion followed are summarized in figure 7. There, the Turbine and BoP CAPEX, the capacity factor and the resulting LCOE are presented versus the turbine size (rated power). The re-distribution of the total CAPEX between the turbine part and the BoP part as the turbine size increases is evident.

2.4 Setting LCOE Targets at the sub-components level

Figure 8 shows the correlation of the blade mass with the rotor radius, demonstrating also the technology evolution in time. All coloured 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 UD 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.

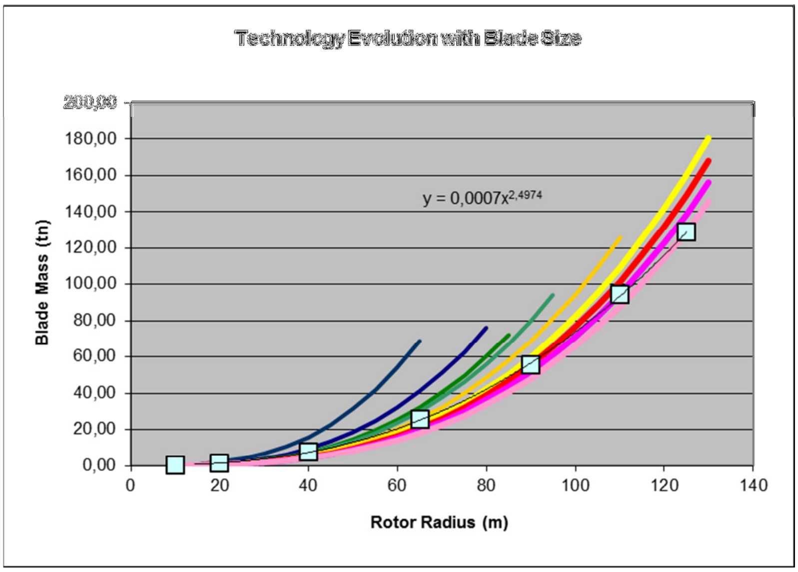

Figure 8 *Scaling-up blade mass – Learning curve [17]*

Figure 9 presents the turbine top-head-mass evolution trends for multi-MW designs of different drive train technology. The overall trend yields an up-scaling exponent close to 2,2-2,3 for all three architectures of our interest (Traditional Gearbox, Permanent magnet Direct Drive and Electromagnetic DD).

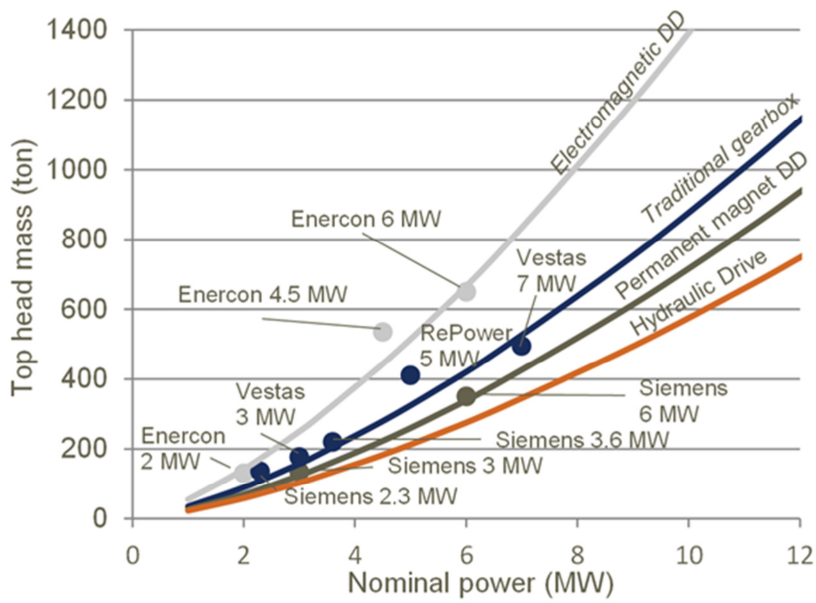

Figure 9 *Trends in top-head-mass up-scaling [20]*

Regarding the support structure let us distinguish between the turbine tower (from tower-top to the transition piece) the transition piece itself and the offshore foundation part (from the transition piece to the sea bottom).

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 [21]) we have shown in [19] that the resulting weigh 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 [19] with a fixed blade–mean sea level clearance(h_{clear}), where the up-scaled tower is expressed as $H(s) = s.\frac{D_1}{2} + h_{clear}$ instead of $H(s) = s.H_1$ (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 $\lambda_w \cong 2{,}7$ (details available in the author's Mathematica Notebook "Tower upscaling fc.nb"). We can assume that a similar scaling law is valid for the transition piece as well (which is initially expected to follow the cubic law).

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 $\lambda \cong 1{,}7$ (details in "Tower upscaling fc.nb"). Until having a dedicated cost-model for jackets we shall assume that this mass scaling exponent is also valid for up-scaling the mass and the cost of jackets of fixed height.

Based on the above discussion and referring once again on our assumption that the cost scales-up proportionally to the weight, the ***proposed target values*** for λ_c and *r* for the CAPEX of the main turbine sub-components are given in Table 7.

Table 7. *Target values of λ_c and r for the CAPEX of critical sub-components*

	Innovative 10MW	
	s =	***1,41***
Subcomponent	**λ**	***r***
rotor blade	*2,30*	*0,78*
nacelle-system	*2,60*	*0,87*
tower	*2,50*	*0,84*
offshore fundation system	*1,50*	*0,59*

The s, λ_c and *r* quantities are non-dimensional and their definition is discussed above in equations (1) to (3). Note that λ_c=2,30 for the rotor blade is equivalent with a 22% cost reduction (1-0,78) when building the 10 MW blade with today's (5 MW technology).

The assumption of the proportionality between the mass and the cost scaling will be altered as soon as we have reliable 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 meaningful way.

Further, using the format of Table 7, we can assign target values to the CAPEX of the individual components in more detail as shown in Figure 10. In this case we up-scale from the 5 MW reference design to the Innovative10 MW design. The "overall / weighted" up-scaling exponents obtained for the Turbine (2,42) and the BoP (1,50) are those used earlier in figure 5.

REF TURBINE (EWEA 5 MW)							Turbine Upscaling Exponent
Capacity (MW)	5,00						2,42
Turbine Cost (M€/MW)	1,500					Subcomponent costs (M€)	Upscaling exponents
Turbine Only	Rotor	*Rotor lock*	*0,0000*	0,2357	1,00	0,000	2,50
		Blades	***0,2220***			1,665	2,30
		Hub	*0,0137*			0,103	2,80
	Nacelle systems	*Gearbox*	***0,1291***	0,2979		0,968	2,60
		Generator	***0,0703***			0,527	2,00
		Rotor brake	*0,0132*			0,099	2,50
		Nacelle cover	*0,0135*			0,101	2,50
		Nacelle structure	*0,0280*			0,210	2,50
		Couplings	*0,0000*			0,000	2,50
		Shaft	*0,0191*			0,143	2,70
		Yaw system	*0,0125*			0,094	2,70
		Bearings	*0,0122*			0,092	2,70
	Electrics & control	*Pitch system*	*0,0266*	0,0767		0,200	2,30
		Variable speed system	***0,0501***			0,376	2,00
	Tower		***0,2630***	0,2630		1,973	2,50
	Other		*0,1300*	0,1300		0,975	2,50
						7,525	
							BoP Upscaling Exponent
BoP Cost (M€/MW)	2,000						1,50
						Subcategory costs (M€)	Upscaling exponents
BoP Only		*Foundation system*	***0,4400***		1,00	4,400	1,50
		Offshore transportation and installation	***0,3000***			3,000	1,00
		Offshore electrical I&C	***0,2600***			2,600	2,00
						10,000	

UPSCALED TURBINE						
Capacity (MW)	10					
Turbine Cost (M€/MW)	1,742					Subcomponent costs (M€)
Turbine Only	Rotor	*Rotor lock*		0,2276	1,00	0,000
		Blades	***0,2121***			3,695
		Hub	*0,0156*			0,271
	Nacelle systems	*Gearbox*	***0,1368***	0,3014		2,384
		Generator	***0,0605***			1,055
		Rotor brake	*0,0135*			0,235
		Nacelle cover	*0,0138*			0,241
		Nacelle structure	*0,0287*			0,499
		Couplings	*0,0000*			0,000
		Shaft	*0,0210*			0,365
		Yaw system	*0,0137*			0,239
		Bearings	*0,0134*			0,233
	Electrics & control	*Pitch system*	*0,0254*	0,0685		0,443
		Variable speed system	***0,0431***			0,752
	Tower		***0,2693***	0,2693		4,691
	Other		*0,1331*	0,1331		2,319
						17,422
BoP Cost (M€/MW)	1,684					Subcategory costs (M€)
BoP Only		*Foundation system*	***0,4394***		1,00	7,400
		Offshore transportation and installation	***0,2519***			4,243
		Offshore electrical I&C	***0,3087***			5,200
						16,843

Figure 10 ***LCEO Calculation for up-scaling with innovative designs***

2.5 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 some 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 8 presents the sensitivity of the rotor, nacelle, tower and offshore foundation mass (and in most of the cases cost) to these design parameters in terms of up-scaling exponents (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 8 we 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 are not prepared at this point to discuss the rotational speed sensitivity to the rotor cost 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.

Table 8. *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

Regarding the downstream influence of the nacelle mass (reduction for any possible reason) we see in the table 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 foundation masses. 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. 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 pursuit. The concept of low-induction rotors is again a sound option for design thrust reduction.

It should be noted once more that all our 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.

2.6 Net Present Value (NPV) and Internal Rate of Return (IRR) as a Key Performance Indicator

The cost of capital of an offshore wind farm varies with a number of factors such as the risks associated with the investment, the down payment required at the start of the project and the Capital Recovery Factor (CRF) which breaks down the overall cost of capital into annualized payments each year. The revenue earned by the wind farm owner is based on the selling price of electricity into the grid, which varies over the life of the wind farm and over market pricing on different days. Most countries have beneficial incentive pricing for renewable power over and above the market price of electricity so that risks in revenue procurement for the wind farm owner are reduced [7]. A tax incentive is also applicable based on the energy fed to the grid.

The net income for the wind farm owner over the life of the wind farm, but calculated over each year is termed as the Net Present Value (NPV) for the year in consideration, The computation of this annual value for the wind farm owner (or customer) can also be based on the Internal rate of return (IRR). This rate of return decides the number of years that it takes to break even (or 0 loss/gain) from the costs incurred in developing the wind farm due to sale of power to the grid. This is a crucial deciding factor for investment decisions in wind farms as the wind turbine technologies that allow faster break even time are much more likely to be wide selling than wind turbine technologies that require many years of farm operation to break even.

The wind farms cost models from the LCOE sheet are used at the starting point to compute the IRR or NPV. The levelized investment costs and the annual O&M costs from Fig. 5 are input to the IRR work sheet given below in Fig.11 for fixed wind farm capacity.

Assumptions User Input				
Turbine cost (€)	**17400000**	scales with MW and no. of turbines		
Variable BOP+foundation(€)	14000000	scales with MW and no. of turbines		
Fixed BOP costs (€)	3000000	scale with no. of turbines		
Capital Cost (€)	34400000.00			
Debt (%)	100.00			
Debt rate (post tax) (%)	5.40			
Loan Term (yrs)	25.00			
Life for wind farm (yrs)	25.00			
Annual Wind Turbine Operating Cost (€)	13500000.00			
Operating Cost Escalation per year (%)	2.00			
Price of Electricity Produced (€/kWh)	0.08			
Green electricity price premium (€/kWh)	0.00			
Annual Bulk Power Rate Increase (%)	2.00			
O&M Discount rate (%)	7.40			
Target IRR	20.00			
Rating of Wind Turbine (MW)	10.00			
Capacity Factor	0.50	Turbine level		
Levelized Tax Credit (€/KWH)	0.00			
Wind Farm Capacity (MW)	300.00			
Number of turbines	**30.00**			
Wind Farm efficiency	0.94	depends on no. of turbines		

Figure 11 : *Assumptions and user input for the computation of Internal return rate of a wind farm of fixed capacity*

The following assumptions are used while computing the IRR:

1) The turbine cost is per MW and input by the user

2) The BoP is divided into two components 1) that scales with the turbine rating and 2) scales with the number of turbines in the farm only and is independent of rating
3) 100% funding of capital (as loan) is assumed, but that can be changed by the user if needed.
4) An inflation of 2% is assumed on the annual operating cost every year. A premium for renewable energy can be input by the user if required.
5) The price of electricity is assumed as €0.08/kWh and it is assumed that this increases by 2% every year. A green energy premium benefit per KWH can also be entered if applicable.
6) A tax credit of 0.1% of the energy produced by a single turbine is assumed per KWH of farm output.
7) A wind farm wake loss of 0.2% per wind turbine is assumed in the energy output of the wind farm.

The above inputs are used to compute the total cost incurred and the total revenue obtained on an annualized basis as depicted in Fig. 12. The LCOE is also computed each year and the averaged LCOE over the farm lifetime of 25 years is used. The IRR and NPV computation formula in MS Excel is used to obtain the IRR and NPV of the wind farm.

Year		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Energy Produced (kwh)		1222808400.00	1222808400.00	1222808400.00	1222808400.00	1222808400.00	1222808400.00	###########	1222808400.00	1222808400.00	1222808400.00	1222808400.00	1222808400.00	1222808400.00
Revenue														
Total Generation Revenue	€	103514399.485	105,470,893	107,466,516	109,502,052	111,578,298	113,696,070	115,856,197	118,059,526	120,306,922	122,599,266	124,937,457	127,322,411	129,755,065
Price of Electricity/kWh	€/kWh	0.085	0.08625	0.08789	0.08955	0.09125	0.09298	0.09475	0.09655	0.09839	0.10026	0.10217	0.10412	0.10611
Revenue including Tax Credit		103514399.485												
Cost of Service (Reflecting Capital Cost)														
Levelized OPEX	€	29970000.000	30,569,400	31,180,788	31,804,404	32,440,492	33,089,302	33,751,088	34,426,109	35,114,632	35,816,924	36,533,263	37,263,928	38,009,207
Levelized CAPEX (Principal & Interest)	€	76185789.170	76,185,789	76,185,789	76,185,789	76,185,789	76,185,789	76,185,789	76,185,789	76,185,789	76,185,789	76,185,789	76,185,789	76,185,789
Total Cost of Service	€	106155789.170	106,755,189	107,366,577	107,990,193	108,626,281	109,275,091	109,936,877	110,611,899	111,300,421	112,002,713	112,719,052	113,449,717	114,194,996
Levelized Cost of Electricty	€/kWh	0.087	0.087	0.088	0.088	0.089	0.089	0.090	0.090	0.091	0.092	0.092	0.093	0.093
Average LCOE	€/kWh	0.094												
Net Generation Revenue	€	-2641389.685	-1,284,296	99,939	1,511,859	2,952,017	4,420,979	5,919,320	7,447,628	9,006,501	10,596,553	12,218,405	13,872,694	15,560,069
Carbon Credits	€	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Present Value Calculation														
Net Annual Income or Loss	€	-2,641,390	-1,284,296	99,939	1,511,859	2,952,017	4,420,979	5,919,320	7,447,628	9,006,501	10,596,553	12,218,405	13,872,694	15,560,069
Cumulative Income		-2,641,390	-3,925,686	-3,825,747	-2,313,888	638,130	5,059,109	10,978,429	18,426,056	27,432,558	38,029,110	50,247,515	64,120,209	79,680,278
Net Present Value (25 Year Project)	€	388,528,426.00												
Internal Rate of Return		27.22%												

Figure 12 : *Example of computation of NPV and IRR for a 300MW wind farm with 10MW wind turbines*

A new excel sheet is used for each turbine rating that is used. For a fixed wind farm capacity (say 300MW), this provides a plot of IRR versus LCOE as a function of turbine rating. This plot can then be used to select the best wind turbine rating for a given wind farm capacity.

2.7 Effect of up-scaling and innovation on the wind farm IRR

The above described values of cost and price are input for turbine ratings of 10 MW, 12 MW, 15 MW and 20 MW for a 300 MW offshore wind farm. It is assumed that each of the higher turbine ratings were obtained by up scaling a 5 MW wind turbine. The results of the IRR and LCOE computations are shown in Fig. 13, which reveals that though the LCOE of an up scaled turbine decreases slightly, the IRR for the customer of the wind farm reduces, if there is no innovation driving the cost of the turbine down. 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 13 uses a subsidy of €0.03/KWH on top of the market power price. This implies that a green electricity premium of €0.03/KWH had to be used on top of the normal €0.08/KWH electricity price (in Fig. 11 that describes the input to the wind farm IRR model) to still obtain positive rate of returns for a 20 MW wind turbine. In other words, a 20MW wind turbine can never provide break even returns for a wind farm owner if mere up scaling of wind turbine technology was used, without great subsidies in the revenue from power sales.

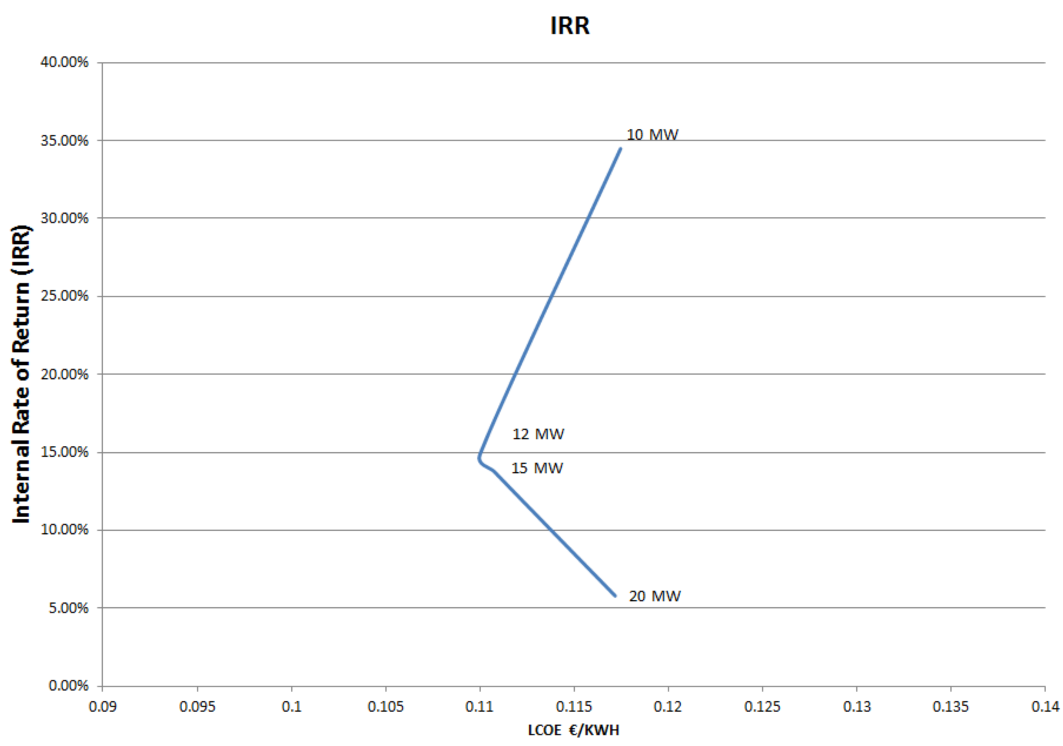

Figure 13 : ***Effect of Up scaled turbine rating on the LCOE and Internal return rate with conventional scaling exponents (no innovation)***

The same computations described above can be repeated but assuming that the 10MW and higher wind turbines are designed using innovative technologies and not through up scaling. The results of these computations are depicted in Fig. 14, which reveals that 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 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.

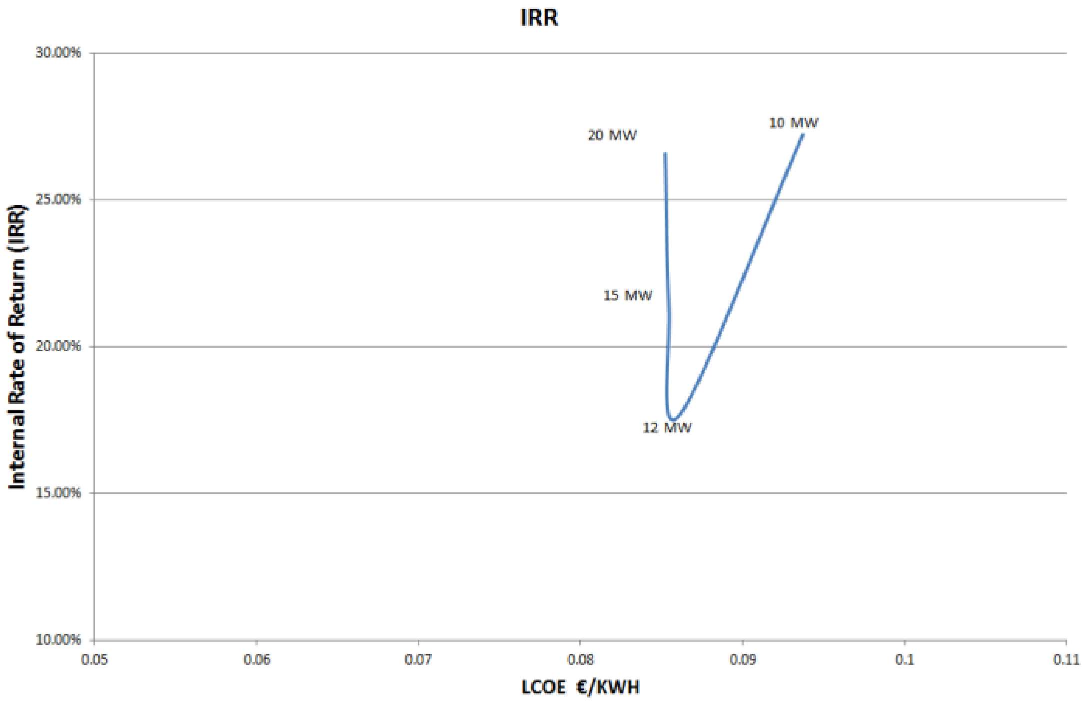

Figure 14: *Effect of Innovative turbine Design as a function of rating on the LCOE and Internal return rate with reduced scaling exponents*

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

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.

The option of moving to 15 MW and higher wind turbine ratings for a fixed wind farm capacity may be decided more from the internal rate of return or value for the customer/wind farm owner rather than by the decrease in LCOE, since the largest decrease in LCOE with innovation (under the present assumptions) occurs in the range of 10 MW- 15MW.

REFERENCES

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

2. http://en.wikipedia.org/wiki/London_Array

3. http://www.eenews.net/stories/1059978057

4. http://www.windpoweroffshore.com/2013/02/21/eon_focuses_on_95mw_goal/#.UZtdAbVmh8E

5. RolandBerger, Offshore Wind Towards 2020; On the pathway to cost competitive-ness, April 2013 , http://www.rolandberger.com/media/publications/2013-05-06-rbsc-pub-Offshore_wind_toward_2020.html

6. http://www.telegraph.co.uk/finance/newsbysector/energy/9413353/Dong-and-Siemens-sign-2.3bn-deal-for-giant-UK-wind-turbines.html

7. The Crown Estate, Offshore Wind Cost Reduction. Pathways study. May 2012

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. Wind Turbine Design Cost and Scaling Model, by L. Fingersh, M. Hand, and A. Laxson, NREL/TP-500-40566, December 2006

13. E.S. Politis and P.K. Chaviaropoulos, Integrated Wind Turbine Design, UpWind Project (SES6-CT-2005-019945), Workshop on Cost Functions Stuttgart, April 8, 2008.

14. 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.

15. Chaviaropoulos, T; 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.

16. Chaviaropoulos PK. Similarity rules for W/T up-scaling. UpWind Report, WP 1B4, 2007.

17. Sieros G, Chaviaropoulos P, Sorensen JD, Bulder BH, Jamieson P. Up-scaling Wind Turbines: Theoretical and practical aspects and their impact on the cost of energy. Wind Energy 2012. 15(1): 3-17

18. Upwind electrical upscaling

19. Sieros G, Chaviaropoulos P.K. 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.

20. BTM Consultants, World Market Update 2011,

    http://www.btm.dk/reports/world+market+update+2011

21. Structural steelwork, Analysis of safety against buckling of shells”, DIN 18800

    Part 4, Nov. 1990N. Dunford and J. Schwartz, Functional Analysis, v. 2, JohnWiley and Sons, New York, 1963