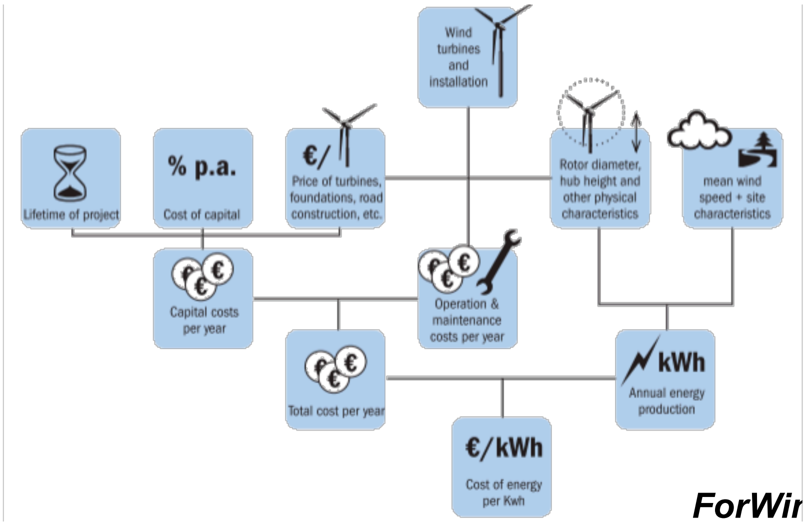
Design of Wind Energy Systems
SS 2016



Lecture 3: Economics of Wind Turbine Design

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ForWind – Wind Energy Systems

Contents

I. Compliance with certification requirements

- International: IEC 61400-1
- Germany: DIBT Guidelines
- Available certification for a certain WT

IEC 61400-1 ed.3 : Wind Turbine Generator Systems – Safety Requirements

- IEC = International Electro-technical Commission
- International standard for wind turbines with > 40 m² swept area, relevant worldwide with exception of Germany and Denmark, issued as EN Standard by CENELEC
- Part 1 („-1")
  - safety requirements, load cases, structural integrity for entire wind turbine
  - no component design
- 3rd edition 2005
- 4rd edition (forecasted 2016-10-01)

- Offshore edition 61400-3 (extension of 61400-1)

Type class concept according to IEC 61400-1 ed.3

IEC: Type classes I – III and S

- V_{ref} : mean (10 min.) wind speed with 50 years recurrence period
- V_{ave}: annual average wind speed = 0.2 * V_{ref}
- I_{ref} : mean turbulence intensity at 15 m/s (class A, B or C)

⇒Wind conditions at hub height

Wind turbine class		I	II	III	S
V_{ref}	(m/s)	50	42.5	37.5	
$V_{ave}=0.2\,V_{ref}$	(m/s)	(10)	(8.5)	(7.5)	Values specified by the designer
A	I_{ref} (-)		0.16		
B	I_{ref} (-)		0.14		
C	I_{ref} (-)		0.12		

Concept of type classes enables:

- simplified building permits
- product standardisation and series production
- short delivery time

Germany: Type approval acc. to DIBt
(Deutsches Institut für Bautechnik)

According to German buiding legislation »a wind turbine is a machinery supported by a civil structure«.

⇒ Thus in Germany any wind turbine has to comply with the national building legislation.

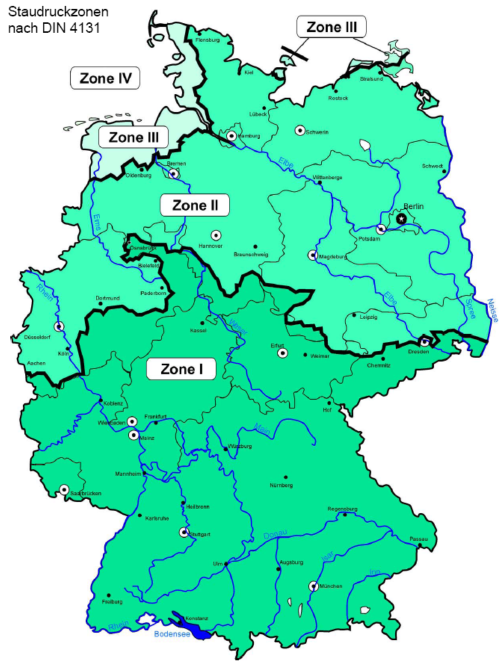
⇒ Building permit is granted by the responsible (local) building authority based on a type approval or a individual approval.

⇒ DIBT Guideline »Richtlinie für Windkraftanlagen des Deutschen Instituts für Bautechnik«, Oct. 2012.

DIBt

Type approval acc. to DIBt

- Stability check of tower and foundation based on one of four regional wind zones (»Windzonen«, WZ) with prescribed extreme dynamic pressure acc. to DIN EN 1991-1-4
  - WZ I: approx. 60 % of country (far inland)
  - WZ II: approx. 30 %
  - WZ III: approx. 9 %
  - WZ IV: approx. 1 % (islands)



- Prescribed design parameters e.g. annual average wind speed, turbulence intensity, extreme 50 years gust wind speed
- The wind zone depends only on the geographical location rather than on the wind conditions at hub height (see »type classes« acc. to IEC 61400-1)

⇒ **a turbine with the proper type approval can be installed at several associated sites**

Definitions of wind speeds acc. to DIBt

DIBt guideline refers to *wind speed at 10 m height*.

Definitions:

Mean wind speed v_m : wind speed averaged over a period of 10 minutes

Annual average wind speed v_{ave} : long-term average of the wind speed over several years. Generally: $v_{ave}(z) = 0{,}18 \cdot v_{m50}(z)$

50-years-wind v_{m50} : mean (10 min.) wind speed with 50 years recurrence period

50-years-gust v_{e50} : wind speed avergaed over 3 s with 50 years recurrence period

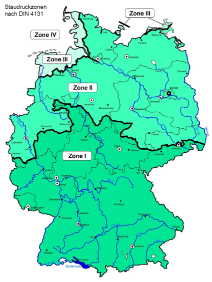
Reference wind speed v_{ref}: *50-years-wind* at 10 m height in flat, open terrain. (IEC 61400-1 is denoting V_{ref} (upper case *V*), i.e. the max. wind speed with a recurence period of 50 years, the governing parameter for turbine design purposes.

Applicable wind speeds acc. to DIBt wind zones

DIBt Guideline refers to the *wind speed at 10 m height*.
Power law used to convert to hub height wind speed

$$v(z) = v(10)\left(\frac{z}{10}\right)^{\alpha} \qquad \text{height } z \text{ in m}$$

Annual average wind speed at hub height : $v_{ave}(z) = 0.18 \cdot v_{m50}(z)$



	50 years mean (10 min) wind speed $v_{ref} = v_{m50}(10)$	50 years extreme (3 s)wind gust $v_{e50}(10)$
Wind zone	Wind shear exponent α = 0,16	α = 0,11
I	24.,3 m/s	35.5 m/s
II	27.6 m/s	39.6 m/s
III	32.0 m/s	45.8 m/s
IV	36.8 m/s	51.2 m/s

Example of the available certification for a certain WT type

The folders of the OEM specific the available certification acc. To international (IEC, NVN, GL) and German (DIBt) guidelines.

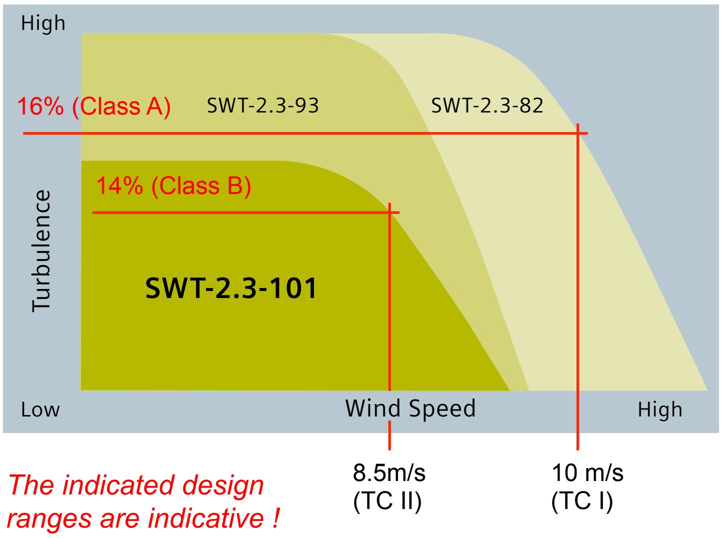
The certificates differ between WT (e.g. diameter, power, series) and hub height !

Baureihe	Rotor-durch-messer	Naben-höhe	Statement of Compliance	GL Typen-klasse	IEC Klasse	Typenzertifizierung	IEC Klasse	Typenprüfung	Wind-zone DIBt
REpower Systems	MD 70	65	✓	2				✓	3
			11/2004*		IIa				
		80						✓	2
		85	✓	4				✓	2
		90						✓	2
	MM 82	59	11/2004*		IIa			✓**	3
		69	11/2004*		IIa				
		80	11/2004*		IIa	06/2005*	IIa	09/2004**	3
		100	12/2004*		IIIa			✓**	2

* erwartet; **zugehörige Gutachten noch nicht vollständig
Stand 09/2004 - Änderungen vorbehalten
Bitte beachten: bei vertraglicher Fixierung von Komponenten ist die jeweilige Kombination im Vorwege zu prüfen!

Example of the available certification for a certain WT

Many WT certified according to the type class concept provide some design margin for slightly more severe wind conditions or are compatible with combination of v_{ave} and I_{ref} that differ form IEC 61400-1.
=> site specific load check and individual approval



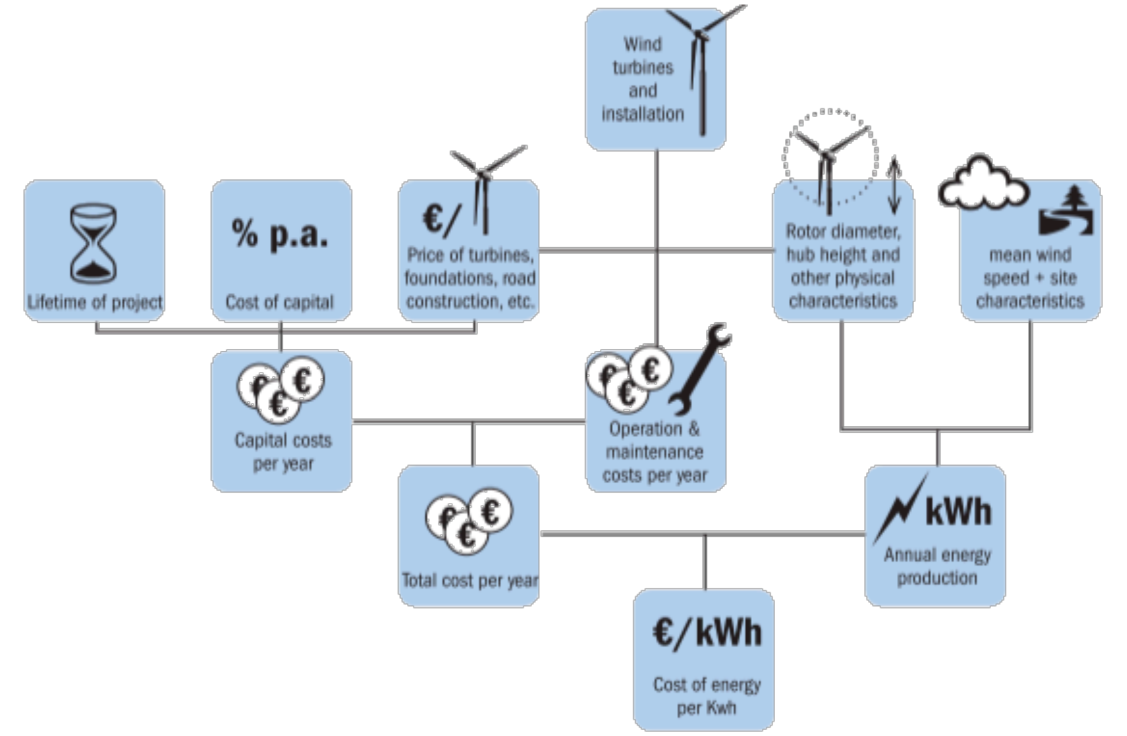
The indicated design ranges are indicative !

Design envelope of G2 platform of *Siemens Windpower*:
- SWT-2.3-82 2.3 MW ø 82m
- SWT-2.3-93 2.3 MW ø 93m
- SWT-2.3-101 2.3 MW ø 101m

II. Cost modeling for early design purposes

- Motivation
- Cost Models and Economic Evaluation
- Excursus: Annual Energy Production
- Relative Cost Modeling
- Concept Optimization

Components of cost of wind energy



Cost modelling: why?

Upfront (investment) costs are approx. 75% of whole wind energy cost
- cost of rotor-nacelle-assembly and tower
- foundation
- grid connection

Section III:
Techno-economic optimisation of wind turbines

Objective
Understanding some criteria that driven the product development of wind turbines

- Approach 1: Turbine design for lowest cost of energy
- Approach 2: Turbine design for series production
- Approach 3: Turbine design for high penetration of wind power

see Lecture 1/Slide 30

Turbine design is based (largely) on optimization of cost of energy

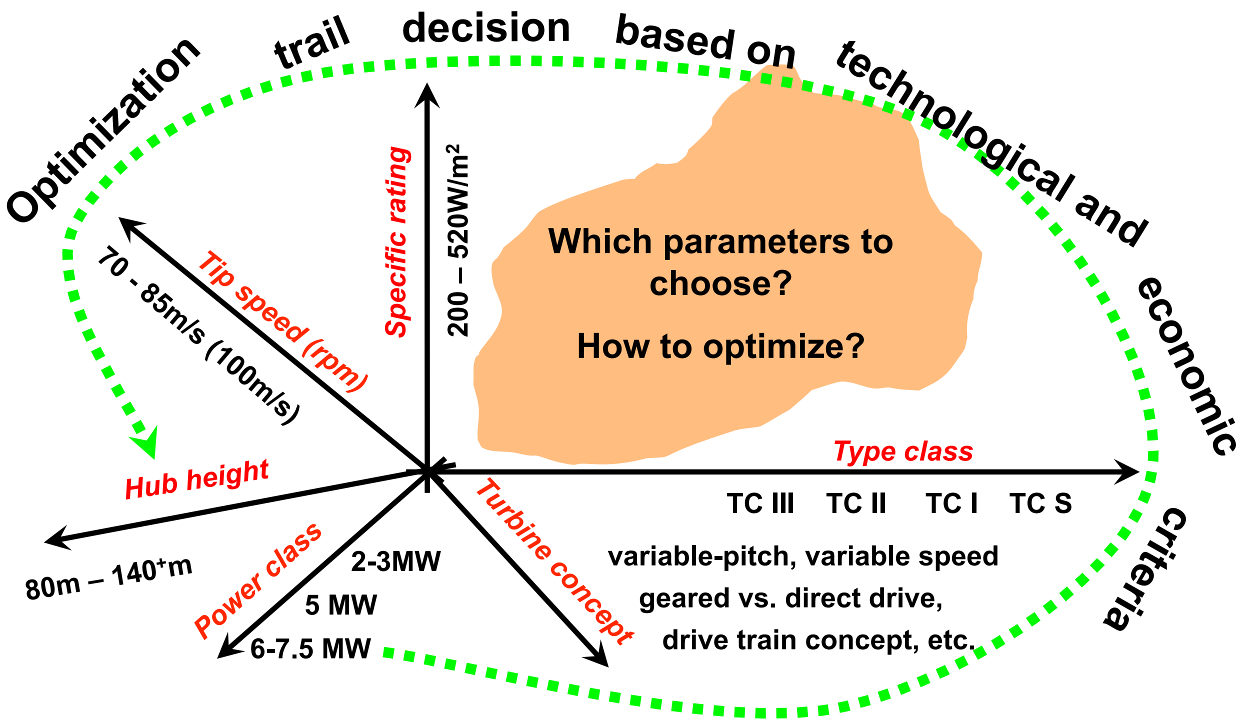
Turbine design for lowest cost of energy

Assumption:
Feed-in tariff is independent or less dependent from the capacity factor

⇒ lowest cost of energy (€ct/kWh) at a given will be optimum
⇒ the specific rating should be optimized site specific

Note:
In Germany the feed-in tariff depends on the wind potential at the site i.e. the energy yield of the turbine at the actual site within the first 5 years (so-called "Referenzertrag").

Multi-dimensional space for conceptual design



Cost models

Empirical cost models

- Environmental conditions

  => empirical change of standard design load parameters (e.g. flapwise blade-moment, torque)

  => empirical relationship => relative change of mass

  => relative cost change
- Cf.: Wind Energy Handbook

Physical cost model

- Environmental conditions => turbine type => loads

  => physical dimensioning => mass

  => absolute cost

  cost are generally related to mass, partly additional factors, adding complexity
- Cf. Sunderland model in WEGA- und Opti-OWECS project, Risoe model in JOULE II

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Methods for calculation of investment cost

	Suitability for optimization:
1. Investment parameters	
▪ ~~Ratio of spec. investment and installed rated power [€/kW]~~	not useful
▪ Ratio of spec. investment and annual yield [€/kWh]	useful with some reservations
2. Static methods (values constant in time)	
▪ <u>Simple methods, suitable for evaluation of technology and site</u>	
▪ E.g.: annuity method, EPRI TAG method, **<u>Levelised Production Cost</u>** (LPC) of IEA	useful
	important for specific markets
3. Dynamic methods (values change over time)	
▪ Applicable for complex investment decisions	
▪ E.g.: present-value method, prediction of cash flow), <u>Return-on-Investment method</u>	useful

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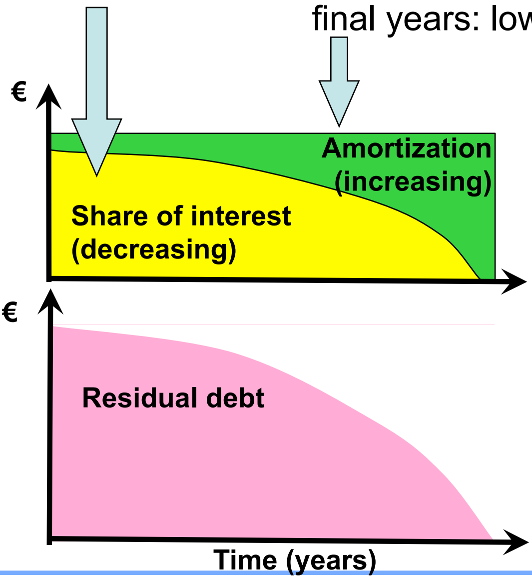
Annuity method

- static calculation of investment cost
- annuity A = constant annual cost (interest + amortization)
- first years of repayment: high share of interest (arising from high debt)

  final years: low share of interest, high amortization



$$A = r + \frac{r}{\left(1 + r^{n_e}\right) - 1}$$

A : annuity [%]

r : interest rate [%]

n_e : period of repayment (economic life - time) [years]

Levelized production cost (LPC)

- Cost over the economic lifetime are discounted by a chosen test discount rate to the start of the operation.
- Constant amount of capital.
- Annuity has to be returned to the lender each year.
- Energy yield and lifetime costs are variable in time, however, their effect on the energy cost is levelised over the lifetime.
- LPC is the ratio of discounted annual cost and net annual energy output (year average).

	Test discount rate †	Repayment period	Annuity factor *a*
Denmark	7 %	20 years	10.6
Germany	varies, 5 % upwards	10 years	7.7 or lower
The Netherlands	4 to 5 %	10 years	7.7 to 8.1
United Kingdom	developer's choice	15 years	
IEA Recommendation ‡	5 %	20 years	12.5

† rate at which the nominal rate exceeds the inflation rate
‡ for comparison of different energy sources

Reference:
Tande, J.O.; Hunter, R., 1994, Recommended Practices for Wind Turbine Testing: 2. Estimation of Cost of Energy from Wind Energy Systems, IEA, 2nd ed.

Static calculation of electricity generation cost (i)

$$LPC = \frac{I \ A}{E_Y} + \frac{TOM}{Ey} = \frac{I}{a \ E_Y} + \frac{TOM}{Ey} \text{ where :}$$

$$a = \left(1 - \frac{1}{\left(1 + r^{n_e}\right)}\right) \frac{1}{r}$$

$$TOM = OM + \frac{DC}{a\left(1 + r^{n_e}\right)}$$

LPC : levelized production cost

I : initial investment [€]

r : test discount rate

TOM : totla levelized annual down - time cost

DC : net decommissioning cost [€]

E_Y : average annual energy yield [kWh]

a : annuity factor

n_e : economic life - time [years]

OM : annual operation and maintenance cost [€]

Static calculation of electricity generation cost (ii)

$$\text{LPC} = \frac{1.820.000 \text{ €} \bullet 13{,}6\%}{3.500.000 \text{ kWh}} + \frac{54.000\text{€}}{3.500.000 \text{ kWh}} = 0.071\text{€/kWh} + 0.015\text{€/kWh} = 0.087\text{€/kWh}$$

(cf. following slide)

- High share of interest payments
- No fuel cost
- Developed by the International Energy Agency (IEA) for the comparison of energy sources

Relative cost modeling (based on mass)

(according to Fuglsang & Thomsen) (i)

Change of electricity generation cost:
Δ LPC = LPC (design parameter) / LPC (baseline design)

Assumptions:

- Annual operating costs are a constant ration of the initial investment

$$\frac{TOM}{I} = \frac{\mathrm{TOM_B}}{\mathrm{I_B}}$$

- Constant test discount rate r and economic lifetime n_e

$$a = a_B$$

$$\mathrm{I} = \mathrm{C_T(m)P_C}$$

(P_C = Project Cost)

$$\Delta\mathrm{LPC} = \frac{\mathrm{LPC}}{\mathrm{LPC_B}} = \frac{\mathrm{I}}{\mathrm{E}_Y}\cancel{\left(\frac{1}{\mathrm{a}} + \frac{\mathrm{TOM}}{\mathrm{I}}\right)}\frac{\mathrm{E_{Y_B}}}{\mathrm{I_B}}\frac{1}{\cancel{\left(\frac{1}{\mathrm{a_B}} + \frac{\mathrm{TOM_B}}{\mathrm{I_B}}\right)}} = \frac{\mathrm{I}}{\mathrm{I_B}}\frac{\mathrm{E_{Y_B}}}{\mathrm{E}_Y} = \frac{\mathrm{C_T(m)}}{\mathrm{C_{T_B}(m)}}\frac{\mathrm{E_{Y_B}}}{\mathrm{E}_{Y_B}}$$

C_{TB} = 100% = 1

Relative Cost Modeling (based on mass)

(according to Fuglsang & Thomsen) (ii)

Change of electricity generation cost:
Δ LPC = LPC (design parameter) / LPC (baseline design)

$$\Delta LPC = \frac{\mathrm{LPC}}{\mathrm{LPC_B}} = \frac{\mathrm{C_T(m)}}{\mathrm{C_{T_B}(m)}}\frac{\mathrm{E_{Y_B}}}{E_Y} = \sum_{i=1}^{n} C_i\left(\mu\frac{m_i}{m_{Bi}} + (1-\mu)\right)\frac{\mathrm{E_{Y_B}}}{E_Y}$$

E_{YB} – average annual yield (baseline machine) [kWh/a]

E_Y – average annual yield of turbine [kWh/a]

C_i- relative cost share of i-th component [%]

m_i - mass of i-th component [kg]

m_{B_i}- mass of i-th baseline design component [kg]

μ – share of mass-dependent cost [-], e.g. 0.84

Relative Cost Modeling (based on mass)

(according to Fuglsang & Thomsen) (iii)

- All WT components except gearbox, generator, grid connection and controller
  - WT designs are obtained by scaling all dimensions of components in the same proportion
- Gearbox mass increases with the rotor diameter cubed
- Rating of the generator and grid connection is proportional to the rotor diameter squared
- Controller cost is assumed fixed

$$C_T(D) = C_3(D) + C_2(D) + C_0(D)$$

$$C_T(D) = C_{T_B}\left(C_{C_3}\left(\mu_3\left(\frac{D}{D_{ref}}\right)^3 + (1-\mu_3)\right) + C_{C_2}\left(\mu_2\left(\frac{D}{D_{ref}}\right)^2 + (1-\mu_2)\right) + C_{C_0}\left(\mu_0 \cancelto{1}{\left(\frac{D}{D_{ref}}\right)^0} + (1-\mu_0)\right)\right)$$

Relative Cost Modeling (based on mass)

(according to Fuglsang & Thomsen) (iv)

component	cost in % Of overall cost, %	component	cost in % Of overall cost, %
Rotor blades	18,3	Controller	4,2
Hub	2,5	Tower	17,5
Main shaft	4,2	Brake system	1,7
Gearbox	12,5	Foundation	4,2
Generator	7,5	Installation	2,1
Nacelle	10,8	Transportation	2
Yaw system	4,2	Grid connection	8,3

Overall cost: 100%

C_{C_3}: 80% = 0,8

C_{C_2}: 15,8% = 0,158

C_{C_0}: 4,2% = 0,042

D – Rotor Diameter

D_{Ref} – Rotor Diameter of the baseline WT

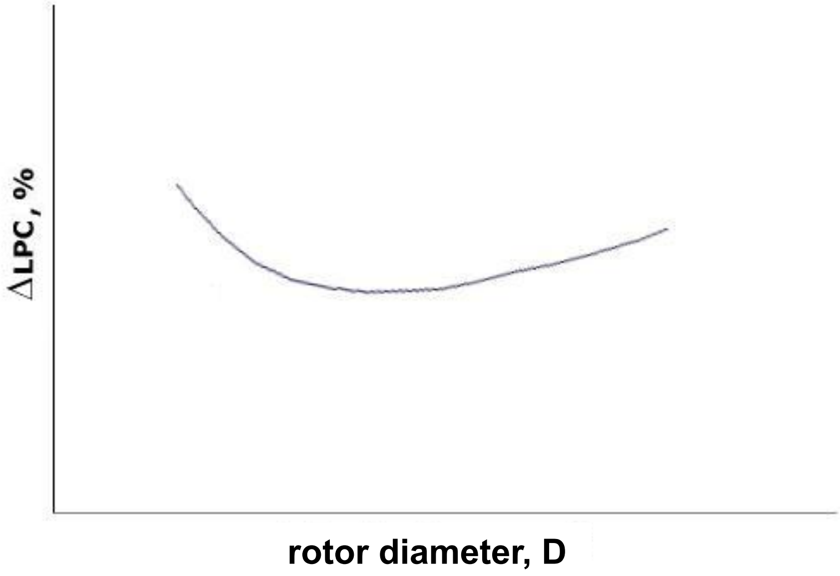
μ = 1 (theoretical assumption)

$$C_T(D) = C_{T_B}\cdot\left(0{,}8\cdot\left(\frac{D}{D_{ref}}\right)^3 + 0{,}158\cdot\left(\frac{D}{D_{ref}}\right)^2 + 0{,}042\right)$$

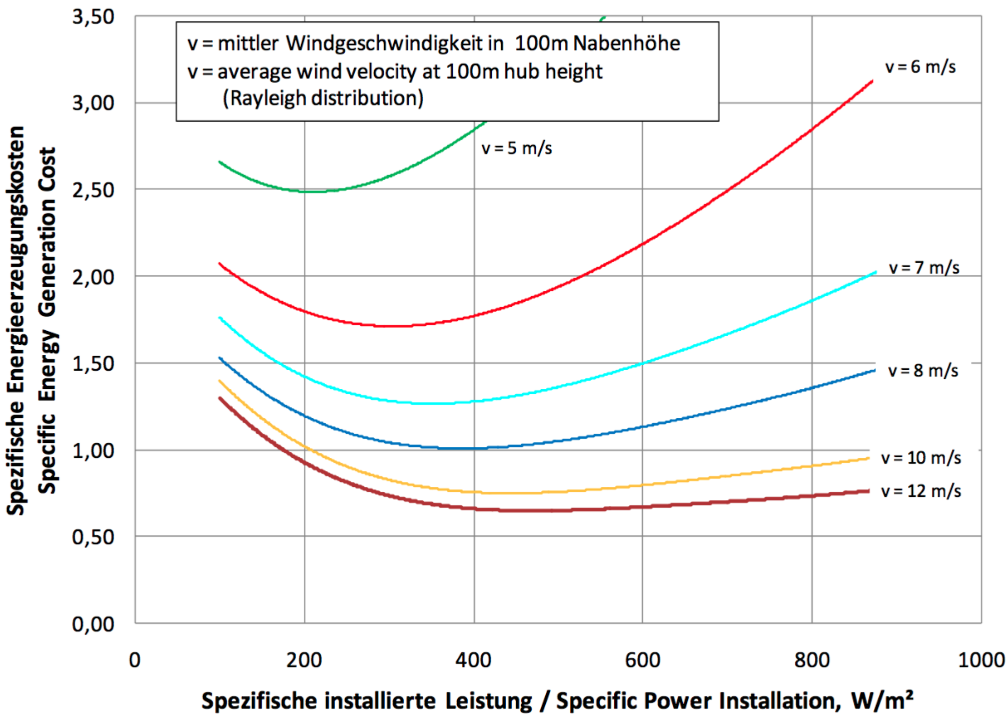
Relative Cost Modeling (based on mass)

(according to Fuglsang & Thomsen) (v)

Variation of energy yield cost with rotor diameter



Optimum of specific cost of energy



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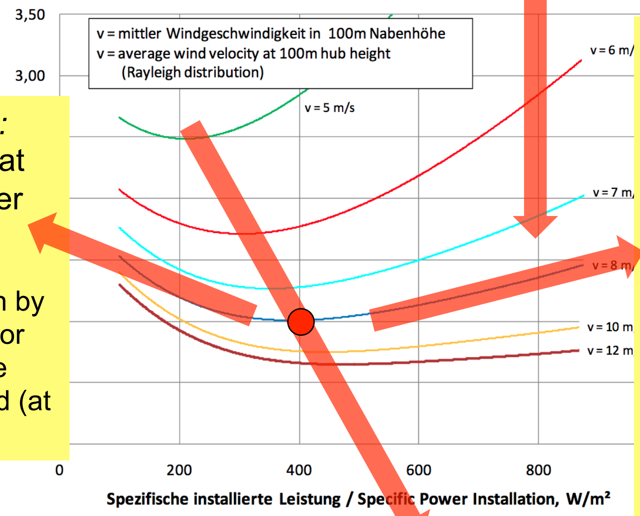
Note: A wind turbine with 400 W/m^2 and a site with v_{ave} = 8 m/s at hub height is taken as reference, i.e. specific energy cost equals 1,00 or 100%.

Specific cost of energy

Strong decrease of CoE for more windy sites
Note: higher V_{ave} for taller towers requires higher investment (optimum hub height will be site and turbine specific)



Left of the optimum:
Too large diameter at constant rated power

Turbine loads and investment cost driven by the increase of the rotor diameter dominate the enhanced energy yield (at partial load)

Right of the optimum:
Too large power rating and/or too small rotor diameter

The investment for a larger power rating and for the blades reinforced for the high rating are not paid off by extra production at full load. Small rotor does not harvest sufficient energy at partial load.

Higher specific rating optimal for more windy sites
Large rotor diameter is relative more expensive a windy sites,
Cost for larger power rating is paid off by higher amount of full load hours

Mass of components as a function of diameter D and nominal wind speed V_r

	D^0	D^1	D^2	$D^{2.5}$	D^3
V_r^0	#	controls 4.2%	#	production 4% & transport, tower (stiffness)	foundation, tower 4.2% (50-year gust)
V_r^1	#	#	#	blade, hub, shaft, frame, tower (fatigue) 57.5%	#
V_r^2	#	#	#	#	Gearbox, brake 14.2% tower (extreme operating gust)
V_r^3	#	#	15.8% Generator, grid connection	#	#

Source: Wind Energy Handbook, Market data

X% = distribution of cost from the Risø cost study (cf. Hau)

Adjust cost distribution according to specific project!!

Component Masses dependent on rpm Ω

mass prop. To	Component	cost fraction for baseline turbine
Ω^{-1}	**hub, gearbox, brakes, frame and yaw system, tower (fatigue)** (10% decrease in mass, if 10% increase in rpm)	49% (- 5% turbine cost)
Ω^{0}	**main shaft, generator, foundation, control system, assembly & transport,** tower (50-year gust) (no effect on mass if speed varies)	33% (cost-neutral)
Ω^{1}	**blade,** tower (extreme operating gust) (10% increase in mass, if 10% increase in rpm)	18% (+ 2% turbine cost)

[Ref. : Wind Energy Handbook]

=> Considerable cost reduction for higher RpM

Adjust cost distribution according to specific project!!

Literature

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