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GreenNet-EU27

GUIDING A LEAST COST GRID INTEGRATION OF RES-ELECTRICITY IN AN EXTENDED EUROPE

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System Operation Cost and Grid Reinforcement/Extension Cost Allocated to Large-Scale RES-E Integration

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1 INTRODUCTION

The core objective of the project **Green*Net*-EU27** is to derive least cost strategies for RES-E grid integration into the European electricity grids. Further important objectives are the dissemination of the project results and practical guidelines to a broad audience, especially to key stakeholders as there are decision makers, regulators, grid companies and RES-E generators. Besides a variety of other dissemination channels the project website www.greennet-europe.org is a core dissemination tool of the project **Green*Net*-EU27**.

This report mainly studies disaggregated system operation cost (i.e. balancing cost, reserve capacity cost for system security) and grid reinforcement/extension cost for different European system configurations caused by large-scale RES-E grid integration. Moreover, background information is presented in subsequent chapters on the modelling approach of system operation cost and grid reinforcement/extension cost in the context of RES-E grid integration in the simulation software **Green*Net*-EU27**. Furthermore, a comprehensive data base (Deliverable D4a; see project website www.greennet-europe.org) – being fully compatible with the structure of the **Green*Net*-EU27** data base – presents the entire picture on system operation cost and grid reinforcement/extension cost for different RES-E penetrations on EU25 Member State's level (incl. Romania, Bulgaria, Croatia, Norway and Switzerland).

The report is organised as follows:

- In chapter 2 the state-of-the-art of renewable energy sources in the European electricity market is briefly summarized both on aggregated level as well as on EU Member State's level. Moreover, the additional mid-term RES-E potentials are shown up to the year 2020.
- In chapter 3 a fundamental discussion on the intermittent nature of RES-E generation is conducted. An overview of different time scales of intermittent RES-E generation is shown and the corresponding system operation requirements are discussed.
- Chapter 4 estimates the additional system operation cost (balancing cost, reserve capacity cost for system security) caused by intermittent RES-E generation based on a top-down approach. This top-down approach is also implemented in the simulation software tool **Green*Net*-EU27**.
- Chapter 5 quantifies the additional grid reinforcement/extension cost allocated to RES-E generation based on the collection of country-specific load flow analyses. Again, the implementation of corresponding cost into the simulation software is shown.
- In chapter 6 excerpts of the comprehensive data base on RES-E grid integration cost in the simulation software **Green*Net*-EU27** are presented.
- Final remarks conclude this report on additional system operation cost and grid reinforcement/extension cost allocated to large-scale RES-E integration.

2 STATE-OF-THE-ART OF RENEWABLE ENERGY SOURCES IN THE EUROPEAN ELECTRICITY MARKET

Electricity generation from renewable energy sources (RES-E) in the EU-25 Member States was 393 TWh in 2003 (i.e. a share of 12.8% of gross electricity consumption). In this context, EU-15 Member States contributed with 377.5 TWh (13.8% of total demand) whereas in the new EU-10 Member States RES-E generation was 15.5 TWh (4.8% of total demand).

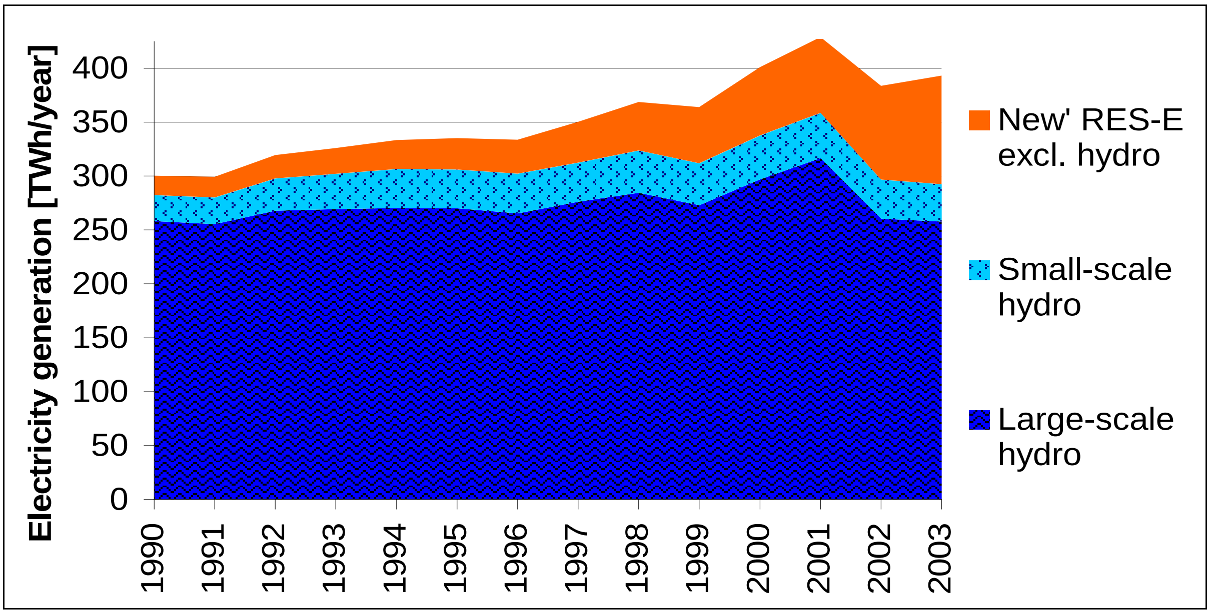

Figure 2.1 Historical development of electricity generation from RES-E (incl. small-scale and large-scale hydropower) from 1990 to 2003 in the EU-25 Member States

Figure 2.1 depicts the historical development of RES-E[1] in the EU-25 Member States for the period 1990 to 2003. Hydropower is the dominant source, but ‘new’ RES-E[2] such as biomass or wind are getting rapidly important.

The following figures provide further insights on several ‘new’ RES-E technologies. Figure 2.2 depicts their historical development, whereas Figure 2.3 indicates a breakdown of their generation on country-level. Wind energy is the RES-E technology with the highest yearly growth rates of about 35% in electricity generation over the last decade. Especially in the EU-15 Member States wind energy is predominant in recent portfolios of ‘new’ RES-E technologies, whereas biomass is dominant in the new Member States.

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[1] The RES-E development is based on EUROSTAT 2003 data. For many RES technologies (e.g. wind-onshore, PV), more recent data from sector organisations and national statistics have been used.

[2] In general, definitions of RES-E sources are made in accordance with the Directive for the promotion of electricity produced from renewable energy sources in the internal electricity market, 2001/77/EC. The technologies assessed include hydropower (large-scale and small-scale), photovoltaics, solar thermal electricity, wind energy (onshore, offshore), biogas, solid biomass, biodegradable fraction of municipal waste, geothermal electricity, tidal and wave energy.

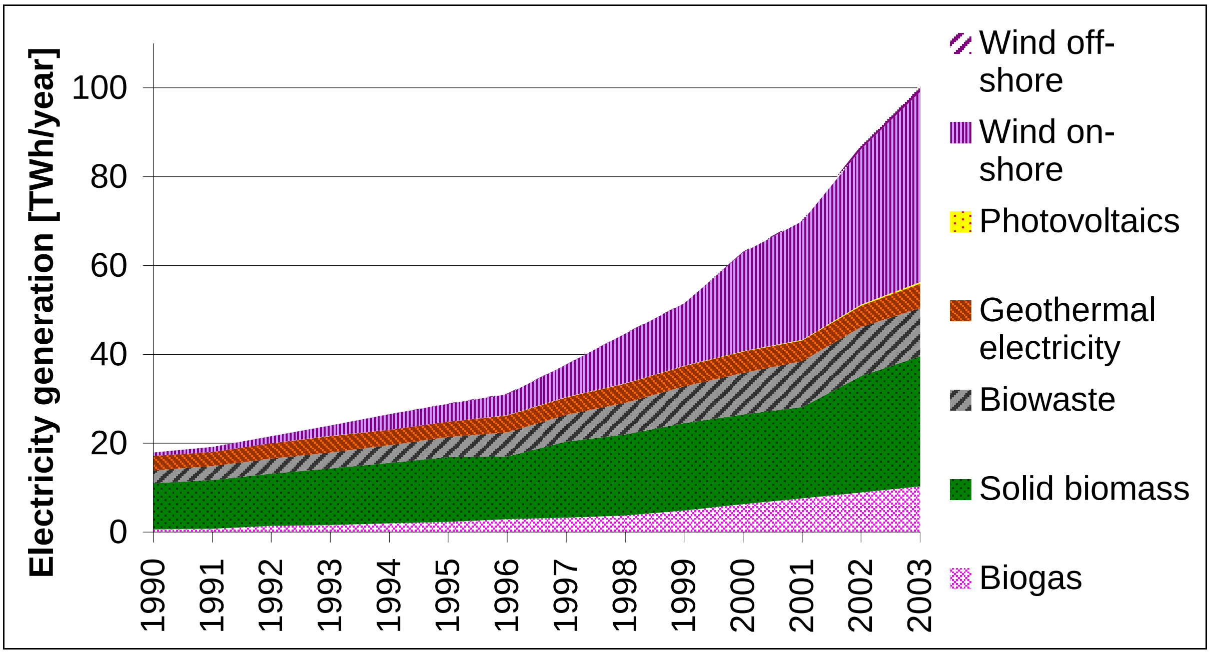

Figure 2.2 Historical development of electricity generation from 'new' RES-E (excl. hydropower) from 1990 to 2003 in the EU-25 Member States

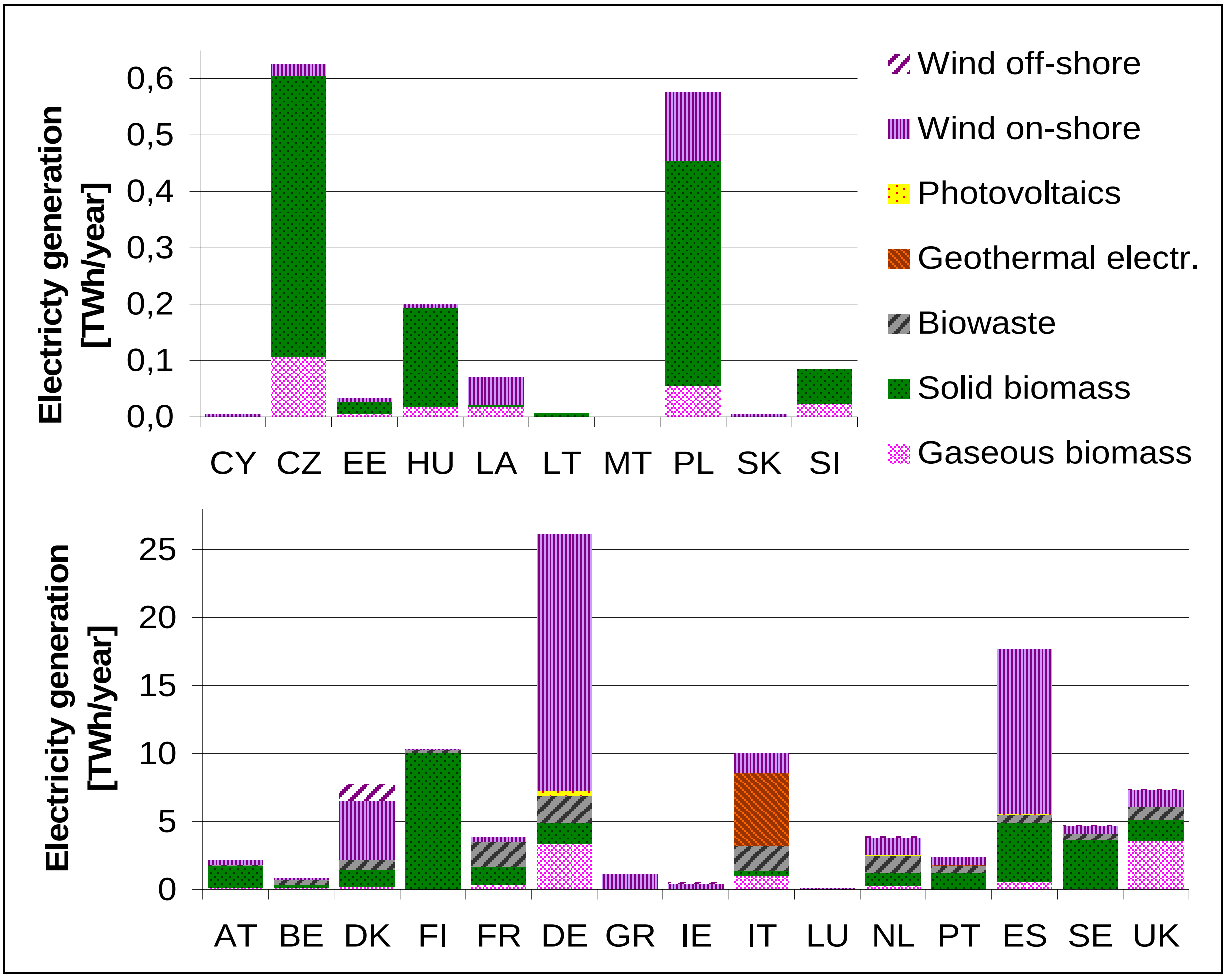

Figure 2.3 Breakdown of electricity generation from 'new' RES-E in the EU-25 Member States on country-level

The high investment cost (and low fuel and O&M cost) of almost all RES-E technologies have been an impediment for broad market penetration. In recent years, investment cost decreased substantially for many RES-E technologies. The main drivers for cost reductions have been research and development as well as economies of scale. Also interest rates have been decreasing over the past two decades.

Figure 2.4 depicts long-run marginal generation cost[3] by RES-E technology. Two different settings are applied describing the payback time:[4] On the one hand, a default setting of 15 years for all RES-E options (Figure 2.4 (left))[5], on the other hand, the payback is set equal to the RES-E technology-specific life time (Figure 2.4 (right)). The broad range of cost for several RES-E technologies represents resource-specific conditions in different regions (countries). Cost also depend on technological options available (e.g. compare co-firing and small-scale CHP plants for biomass).

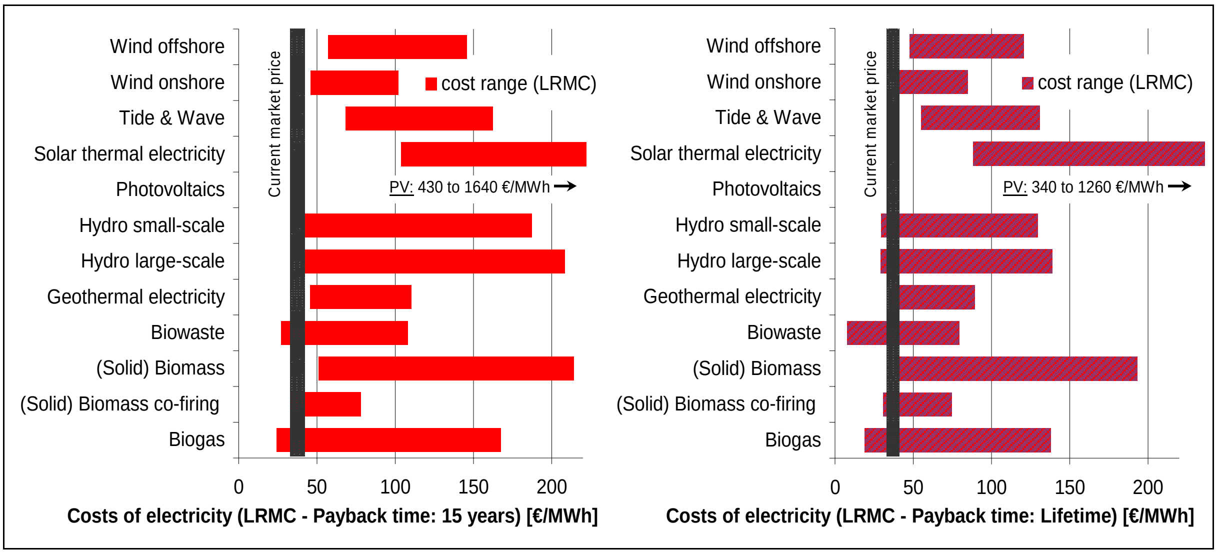

Figure 2.4 Long-run marginal generation cost (for the year 2005) of different RES-E technologies in EU-25 Member States – based on a default payback time of 15 years (left) and payback time equal to lifetime (right).

RES-E technologies such as hydropower or wind energy are energy sources characterised by natural variability. Therefore, in order to provide accurate forecasts of the future RES-E deployment, historical data for RES-E deployment have to be translated into electricity generation potentials, i.e. the achieved potential. More precisely, this potential data refer to the year 2004. Thereby, a forecast is undertaken to deliver missing data on country and technology level for the year 2004.[6] Additionally, future potentials are assessed taking into account the country-specific situation as well as constraints in implementing them. Figure 2.5 depicts the achieved and additional mid-term potential for RES-E technologies in the EU-15 on country-level (left) as well as RES-E technology (right). A similar picture is shown for the

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[3] Long-run marginal generation cost are the indicator whether or not to build a new power plant.

[4] For both cases an interest rate of 6.5% is used.

[5] A payback time of 15 years aims to reflect the investor's point-of-view in competitive, liberalised markets.

[6] On technology-level, actual data for the year 2004 is only available for wind energy and photovoltaics for several countries of investigation.

new Member States (EU-10) and selected Candidate Countries (i.e. Bulgaria, Romania) in Figure 2.6. For EU-15 Member States, the already achieved potential for RES-E generation equals 441 TWh,[7] whereas the additional realisable potential up to 2020 is 1056 TWh (about 38% of gross electricity consumption in 2004). Corresponding figures for the EU-10 Member States are 19 TWh for the achieved potential and 118.7 TWh for the additional mid-term potential (about 36.1% of current gross electricity consumption in 2004).

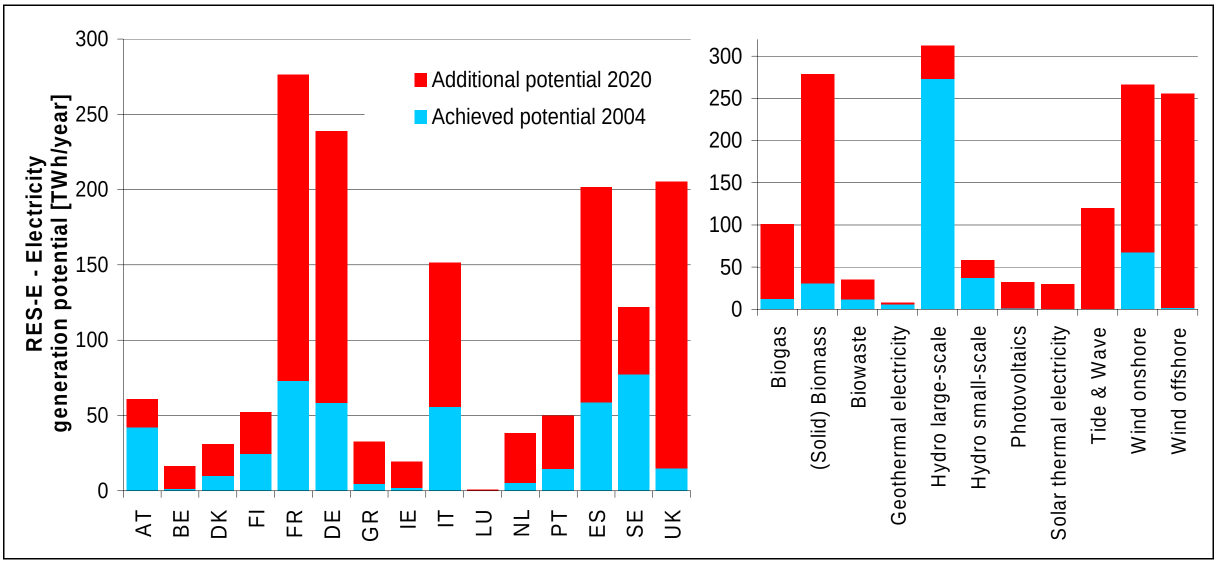

Figure 2.5 Achieved (2004) and additional mid-term potential 2020 for electricity from RES in the EU-15 Member States on country-level (left) and RES-E technology (right)

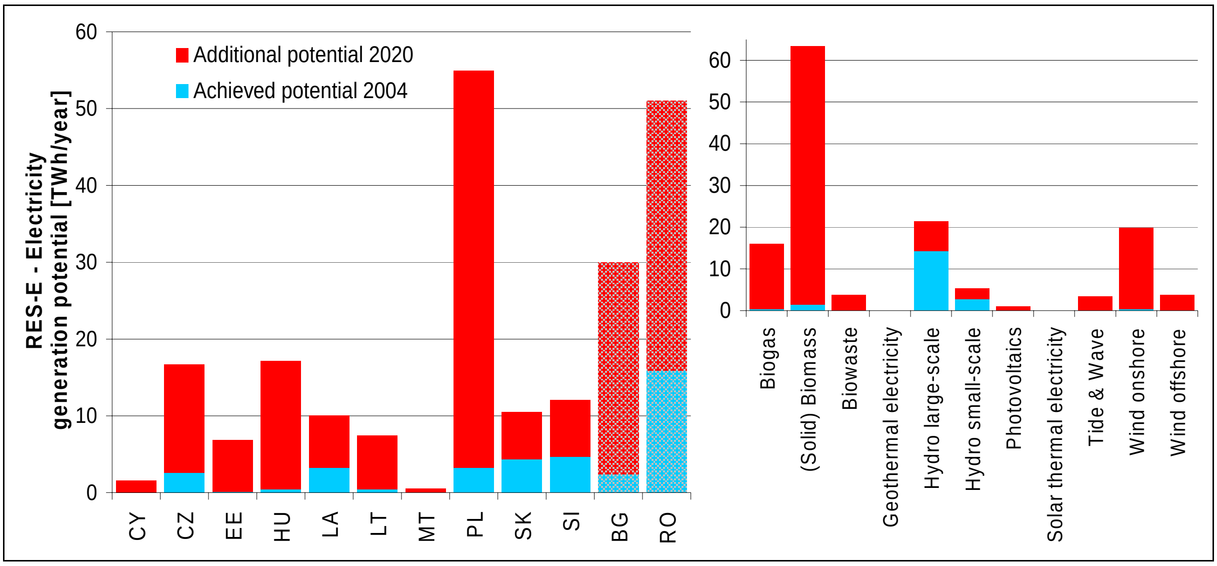

Figure 2.6 Achieved (2004) and additional mid-term potential 2020 for electricity from RES in EU-10 Member States and Bulgaria, Romania on country-level (left) and RES-E technology (for EU-10 Member States only; right)

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[7] The electricity generation potential represents the output potential of all plants installed up to the end of each year. The figures for actual generation and generation potential differ in most cases – due to the fact that, in contrast to the actual data, the potential figures represent normal conditions (e.g. in case of hydropower, the normal hydrological conditions), and furthermore, not all plants are installed at the beginning of each year.

The country-specific situation with respect to the future potential of available RES-E options is depicted below in more detail.

Figure 2.7 depicts the share of *additional* RES-E mid-term potential for the EU-15 Member States in 2020. The largest potential is available in the sector of wind energy (43%) followed by solid biomass (23%), biogas (8%) as well as promising future options such as tidal and wave (11%) or solar thermal energy (3%).

Figure 2.8 illustrates the share of *additional* RES-E mid-term potential up to 2020 for the EU-10 Member States incl. Bulgaria and Romania. In contrast to the EU-15 Member States, the largest potentials for these countries exist in the sectors of solid biomass (53%) and wind energy (19%), followed by biogas (13%). Unlike the situation in the EU-15 Member States, refurbishment and construction of large hydro plants is supposed to be significant (6%).

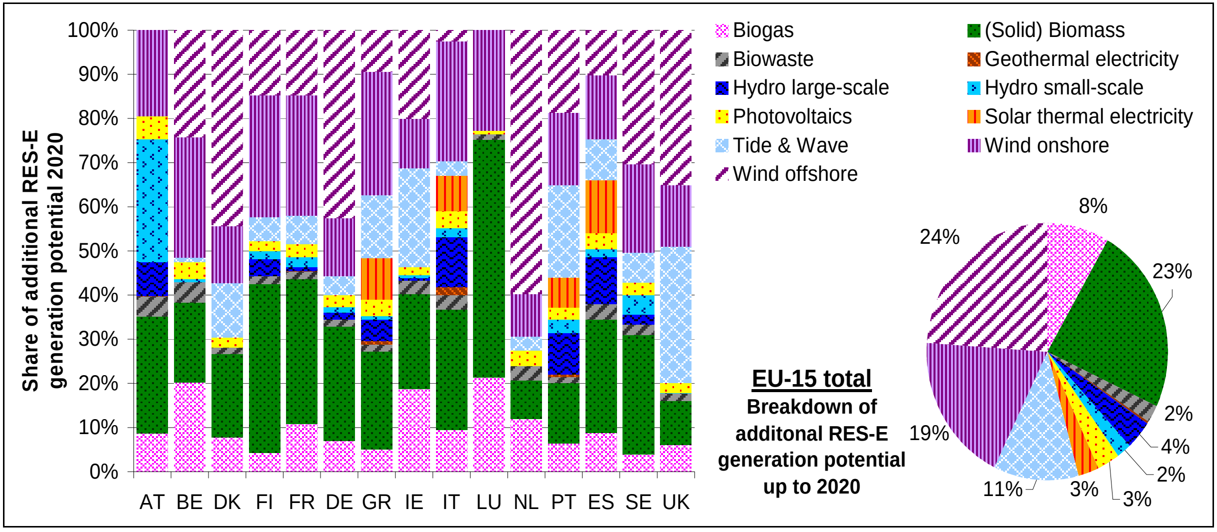

Figure 2.7 RES-E as a share of the total additional realisable potential in 2020 for the EU-15 Member States on country-level (left) as well as for the EU-15 in total (right)

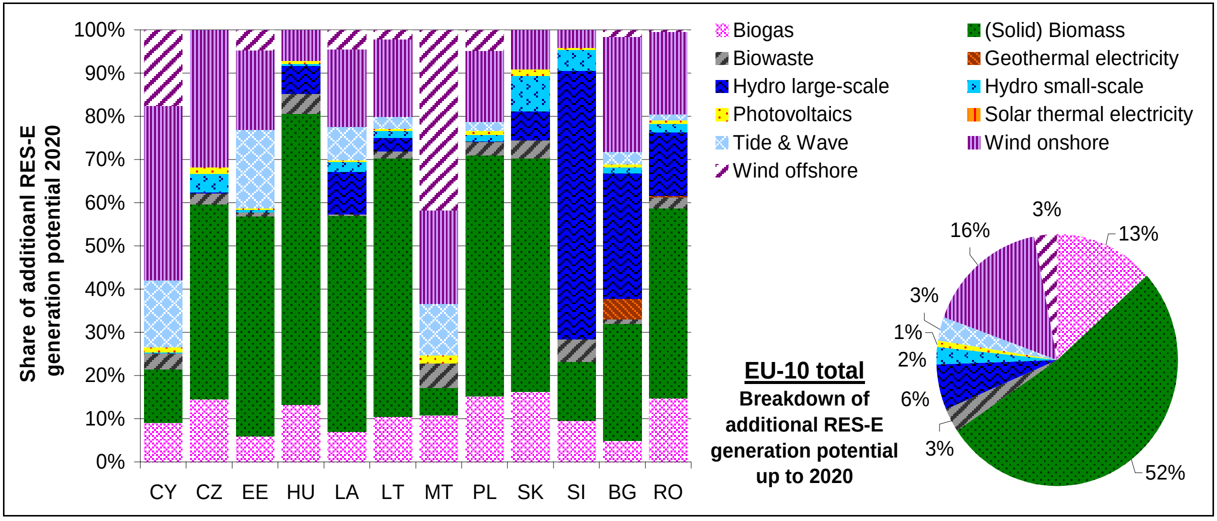

Figure 2.8 RES-E as a share of the total additional realisable potential in 2020 for the EU-10 Member States incl. BU, RO on country-level (left) as well as for the EU-10 in total (right)

3 INTERMITTENCY OF RES-E GENERATION

3.1 Overview of different time scales of intermittency

3.1.1 Intensity and frequency characteristics of renewable sources

Renewable energy is available in many environmental energy flows, as harnessed by a range of technologies. The parameters used to quantify and analyse the various forms are listed in Table 3.1, together with their intrinsic variation in magnitude and time.

Table 3.1 Intensity and frequency characteristics of renewable sources. Source: Twidell (2003).[8]

System	Major periods	Major variables	Power relationship	Comment	Approx time variation
Direct sunshine	24 h, 1 y	Solar beam irradiance G_b^* (W/m^2) Angle of beam from vertical q$_z$	$P \propto G_b^* \cos\theta_z$ $P_{\text{max.}}$ = 1kW/m^2	Daytime only! Highly fluctuating	hours to seconds
Diffuse sunshine	24 h, 1 y	Cloud cover, Perhaps air pollution	$P <\sim 300$ W/m^2	Significant energy, however	day
Biofuels	1 y	Soil condition, solar irradiation, water, plant species, wastes	Stored energy 10 MJ/kg^1	Very many variations. Linked to agriculture and forestry	year
Wind	1 y	Wind speed u_0 Height nacelle above ground z, height of anemometer mast h	$P \propto u_o^3$ *(this is only true for the power in the wind, but not at the shaft of a real wind turbine (because of the regulation of the wind turbine)*	Highly fluctuating	seconds, minutes, hours, months, years
Wave	1 y	'Significant wave height' H$_s$ wave period T	$P \propto H_s^2 \ T$	High power density ~50 kW/m across wave front	week
Hydro	1 y	Reservoir height H water volume flow rate Q	$P \propto H\, Q$	Established resource	months
Tidal	12 h 25 min	Tidal range R; contained area A; estuary length L, depth h	$P \propto R^2 A$	Enhanced tidal range if L / √h = 36000 m$^{1/2}$	12 h
Geothermal	none	Temperature of aquifer or rock formation, hence temperature difference from ambient	$P \propto (\Delta T)^2$	Very few suitable locations for electricity generation	none

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[8] The symbols are standard in the corresponding technologies.

The ability to integrate RES-E generation technologies into electricity grids is governed by several general factors, including:

- variation of generated electricity with time,
- extent of the variation (availability),
- predictability of that variation,
- controllability of power output,
- rated power of each generator,
- dispersal of individual generators,
- reliability of power plant,
- experience of use by operators.

Despite these many apparent difficulties, the experience in the past was that ever-increasing amounts of RES-E generation can be integrated into grids without significant financial penalty. In the past, the standard response of grid operators was that intermittent and dispersed RES-E generation cannot be integrated on large-scale. However, given the requirement to accept specific RES-E generation, the technology and methods to accept that generation have followed successfully. Examples are:

- electrical safety equipment and grid-fault disconnectors,
- grid linked inverters for photovoltaic, solar cell, power from buildings,
- power electronic converters and controllers,
- doubly-fed induction generators for variable speed wind turbines,
- voltage reinforcement on rural power lines,
- co-firing of steam boilers with biomass,
- gas turbines for the output of gasifiers.

The outstanding example of ever-increasing capacity of RES-E generation into the grid has occurred in Jutland, western Denmark. In the early 1980's, the limit for wind power exported to the grid was considered to be 20% of total generation. However, by 2003, about 40% of annual electricity generation was from wind and at times significant areas had 100% of wind generation. The reason for the change was the willingness to apply the new technology and practices.

3.1.2 Selected indicators of RES-E generation technologies

Derived from the description of renewable energy sources qualified for electricity generation in the previous section in this section selected characteristics of several RES-E generation technologies are summarized briefly.

Please note, that there is an enormous variety of characteristics (indicators) which could be mentioned. In Table 3.2 a selection of corresponding indicators is shown as there are:

- volatility (approximation of time variation),
- resource availability,
- range of generation cost,
- preferred voltage level of grid connection.

Table 3.2 Different indicators for RES-E generation technologies

RES-E technology		**Volatility (approx. time variation)**	**Resource availability**	**Range of generation cost [€cent/kWh]** [9]	**Preferred voltage level of grid connection**
Biogas		Year	Large	5,18 – 26,34	1…30kV
Biomass		Year	Large	2,87 – 9,46	1…30kV, except co-firing
Geothermal electricity		Year	In general, small: country-specific	3,34 – 6,49	10…110kV
Hydro power large	Run-of-River power plants	Months	Small	2,53 – 16,37	220…380kV
	Dam/reservoir power plants	Months	Small	not considered	220…380kV
Hydro power small		Months	Medium	2,69 – 24,93	10…30kV
Landfill gas		Year	Medium/small	2,50 – 3,91	1…30kV
Sewage gas		Year	Medium	2,85 – 6,24	1…30kV
Photovoltaic		Day, Hours, Seconds	Large	47,56 – 165,32	<1kV
Solar thermal electricity		Day, Hours, Seconds	Large: country-specific	12,48 – 66,97	1…30kV
Tidal - range		12 Hour	Large	not sufficiently experienced	10…380kV
Tidal – stream/current		12 hour	Medium	under development	
Wave		Weeks	High	9,38 – 45,16	10…380kV
Wind	On-shore	Hours, Minutes	High: country-specific	4,63 – 10,80	30…380kV
	Off-shore	Hours, Minutes	High: country-specific	6,09 – 13,39	110…380kV

Table 3.2 indicates some electricity generation options based on renewable energy sources. In subsequent sections and chapters of this report, we show that *a priori* individual characteristics of RES-E generation technologies need not to be disadvantages as compared with conventional nuclear and fossil electricity generation technologies. Moreover, intelligent scheduling of intermittent RES-E generation (including options for storage and load management on the demand side) encourages innovation for sustainable technological solutions for both electricity generation and demand.

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[9] The range of generation cost is quoted from Auer et al (2005).

3.2 System operation requirements caused by intermittent RES-E generation

With intermittent RES-E generation, corresponding requirements for system operation can be divided into:

- capacity requirements to maintain system security,
- system balancing requirements.

Moreover, the impact of intermittent RES-E generation is analysed in detail by:

- quantifying the capacity of conventional plants required to maintain adequate security of supply in a system having a significant contribution of intermittent RES-E sources, and
- quantifying the additional requirements of balancing the system in the operational time-scale (from several minutes to several hours), often driven by fluctuations in wind generation.

3.2.1 System capacity requirements

In electricity systems, generation and demand has to be balanced at different time scales, varying from seconds to minutes to days and longer. These different time scales have to be discussed separately, especially in the context of large-scale intermittent RES-E grid integration.

In the long-term, the market itself is responsible for providing enough capacity to be able to meet peak demand in the system. This is also true in systems with large amounts of intermittent RES-E generation. Nevertheless, the corresponding requirements due to large scale intermittent RES-E generation have to be estimated although finally the corresponding "cost" are socialised via wholesale markets (sending out the right price signals for building new generation capacities).

In practice, the requirements are quantified by determining the capacity of conventional plants that can be displaced by intermittent RES-E generation, whilst maintaining the same degree of system security. This is the 'capacity credit' of particular RES-E power plants in particular environmental conditions. We note that we should not generalise about any specific RES-E technology, since in each case the environmental 'prime mover' is different; for instance wind turbines in north-western Scotland have higher capacity credit than identical wind turbine capacity in, say, southern Germany. However, despite this proviso, there is a tendency to give a stated capacity credit for each named RES-E technology, which can be most deceptive.

The capacity credit of wind generation is generally interpreted in two ways:

- On the one hand, from a planning perspective, capacity credit should indicate the replaceable conventional capacity in order to set targets for energy policy.
- On the other hand, capacity credit is interpreted as a component of the economic value of wind energy determining avoided or replaced conventional electricity generation.

For small levels of penetration of wind power into the grid, the capacity credit for wind energy is about the same as the corresponding load (capacity) factor. For higher wind penetrations in a system, the kWh generated based on wind becomes less valuable (due to its intermittent nature) for displacing generation from conventional capacities. The corresponding direct indicator – the capacity credit – begins to tail off, see Figure 3.1.

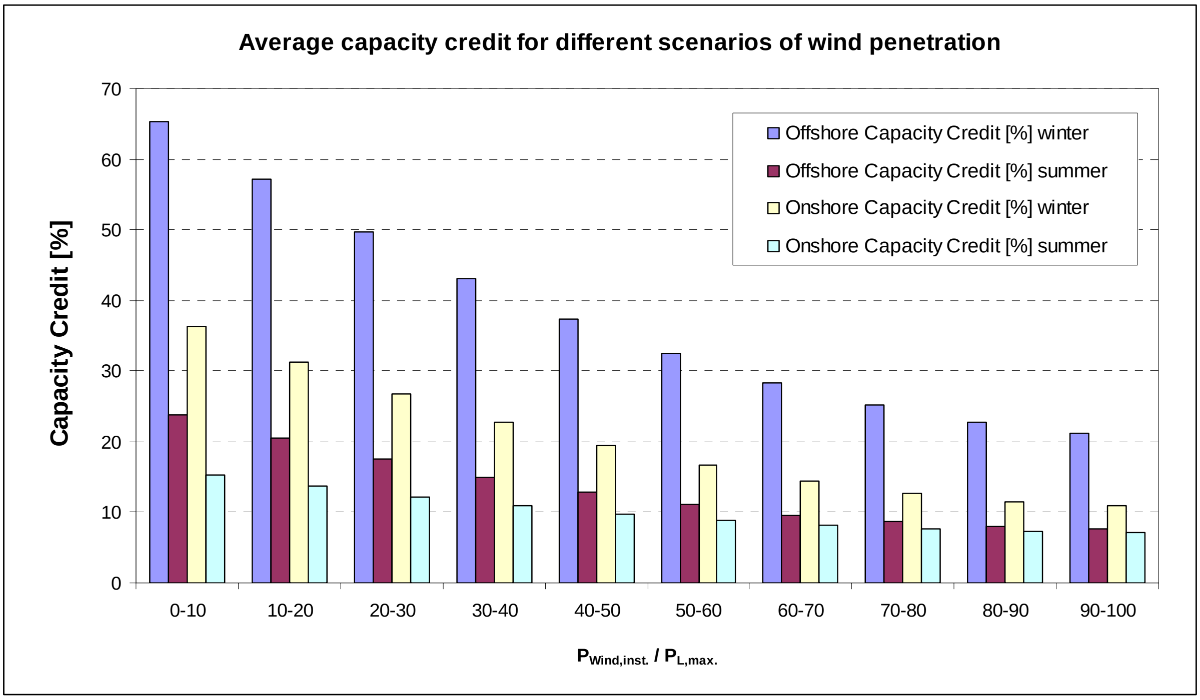

Figure 3.1 Average capacity credit for different scenarios of wind penetration (offshore/ onshore, summer/winter). Source: Results of many studies summarized in Auer et al (2004).

3.2.2 System balancing requirements

As already mentioned in section 3.2.1 above, the consideration of different time scales is important for managing generation and demand. In the short-term (talking about times scales below seconds to several hours) a variety of balancing (ancillary) services are necessary for maintaining stable system operation: e.g. primary-, secondary- and tertiary control (UCTE nomenclature).[10] In this context, system frequency – the parameter used to indicate the balance between generation and demand – must be maintained continuously within narrow statutory limits around 50 Hz. With no change in generation, system frequency decreases when demand is greater than generation and increases when generation is greater than demand.

The UCTE rules and standards on provision of different balancing (ancillary) services can be summarized as follows:

- *Primary Control:* If there is a sudden (unexpected) outage of generation in a control area, the nominal frequency of 50 Hz drops. The balance between supply and demand has to be directly restored as fast as possible by means of the primary control on conventional generators. Disturbances of this balance are initially neutralised by the rotating mass of the generators in power plants. If a surplus of energy is fed into the

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[10] Please note, that the standards described here apply to the UCTE countries only. Other European countries have different standards and nomenclature.

electricity system, the rotation speed of the turbines increases. In case of a shortage, rotation energy is extracted from the turbines, and the rotation speed decreases. Technical devices detect the frequency changes and intervene to restore the power balance and stabilise system frequency. This control function is called primary regulation. Large generators are required to contribute to this service in accordance with the grid code.

- *Secondary control:* After the automatic activation of the primary control, the transmission system operator (TSO) activates the secondary regulation reserve generating capacities within minutes to restore frequency to the pre-set value of 50 Hz and to secure the import/export balance with neighbouring control areas. When this is achieved, the units acting in primary regulation in the whole synchronous system return to their normal operational conditions. This secondary control (or spinning reserve, or rotating reserve) is provided chiefly by storage stations, pumped-storage stations, gas turbines, and by thermal power stations operating at less than full output. Secondary control must begin within 30 seconds of the disturbance concerned, i.e. when the action of primary control is completed, and must be fully deployed within 15 minutes (the minimum duration that primary control must be able to maintain the altered output after activation).
- *Tertiary control:* If the imbalance deviates outside the specified standards, further measures are required. If secondary reserves are lengthy used, offers of tertiary reserves are called upon. Tertiary control (or reserve power) is generating capacity or interruptible load that must be available in the market to maintain the balance in the electricity system during exceptional deviations in demand or generation. In general, these reserves are offered on the balancing market. Tertiary reserves are provided by power plant operators that have to start flexible (e.g. thermal) power stations or reduce their scheduled production for this purpose.

Wind generation and system balancing

In this context, unpredicted fluctuations in the overall output of wind generation, place an additional duty on the remaining generating plants and increase the requirements for system balancing services. The amount of additional resource required to manage unscheduled wind generation will not be on a “megawatt for megawatt” basis. The key factors here are the density and dispersal of wind farms across the whole grid. Within a single wind farm, the output of each turbine may vary significantly within seconds to minutes as the wind changes across its rotor.

Over network scales of about 500 to 1000 km, there is little correlation between wind farms within intervals of days. At intervals of days and more, the particular synoptic weather characteristics dominate the wind strengths and their variation. Therefore additional balancing requirements due to wind mainly address tertiary control and do not have a considerable impact on primary and secondary control requirements.

It is important to stress that system balancing requirements are not assigned to back-up a particular plant type (e.g. wind), but to deal with the overall uncertainty in the balance between demand and generation. Moreover, the uncertainty to be managed in system operation is driven by the combined effect of the fluctuations both (i) in demand, and (ii) in generation from conventional and renewable generation. These individual fluctuations are generally not correlated, which has an overall smoothing effect with a consequent beneficial impact on the cost.

Wind curtailment

If wind generation reaches large penetration in a system and with other forms of dispersed embedded generation on line, there may be occasions when the number of conventional large generation units needed to supply the remaining load will be so few, that adequate capacity of central short-term balancing services cannot be maintained. In some situations, renewable generation could, potentially exceed demand during some periods. A number of actions will have been planned to deal with such potential surpluses of renewable generation, as prioritised with respect to cost. The easiest strategy is to have some renewable plant under central control and for this to be curtailed, as with fossil thermal plant. The least costly options could be to increase demand under ‘demand response options’, e.g. by additional pumping at pumped storage facilities and water supply reservoirs, or, in the future, by hydrogen production.

We note that improvements now available in modern large wind turbines allow their disconnection and reconnection by central grid control without risk of over speed or other harm to the turbines; these control options are likely to be mandatory for offshore wind turbines especially. Such control will be needed when the conventional capacity on the system is insufficient to provide adequate short-term balancing services. Further wind farms may be controlled remotely to reduce generation in order to take part in frequency regulation and reserve tasks. Such participation in grid control is possible with pitch-controlled turbines and their associated power electronics. Therefore, it can be assumed that wind generators will be able to provide response and reserve to at least 10% of their output. If there is still surplus generation left, some of the renewable generation would need to be taken off-line, starting with the technologies with the largest marginal cost, such as biomass.

4 ADDITIONAL SYSTEM OPERATION COST CAUSED BY INTERMITTENT RES-E GENERATION

Derived from the description of the system operation requirements in section 3.2, the corresponding additional costs of system operation caused by intermittent RES-E generation can be divided into:

- additional capacity cost to maintain system security,
- additional system balancing cost.

Moreover, the impact of intermittent RES-E generation is analysed in detail through:

- quantifying the additional cost of conventional plant required to maintain adequate security of supply in a system having a significant contribution of intermittent RES-E sources, and
- quantifying the additional cost of balancing the system in the operational time-scale (from several minutes to several hours), often driven by fluctuations in wind generation.

4.1 Additional system capacity cost (case study of wind power)

The most comprehensive way to calculate the additional capacity cost caused by large-scale wind integration is to conduct a “bottom-up” analyses of the system. More precisely, based on comprehensive load flow analyses the additional capacity requirements can be determined, if wind penetration increases in a system.

The following simplistic approach is used to demonstrate on how to estimate the additional system capacity cost caused by intermittent wind generation (cited from *ILEX Energy Consulting (2002)*).

> *Please note, that the methodology shown below which introduces a “fictitious thermal equivalent” and, subsequently, defines benchmarks for additional system capacity cost due to wind integration, is relevant for any kind of other power plant portfolios, e.g. also for hydro-dominant systems.*
>
> *Moreover, the additional system capacity requirements can also be covered by any kind of additional import capacities (e.g. by extending or building new transmission lines).*

Example

First, the annual wind generation is calculated using installed capacity in MW and proportion of annual full load hours. Then the *equivalent* amount of conventional capacity is determined required to produce the same annual generation, assuming a CCGT (Combined Cycle Gas Turbine) at 85% load factor. No attempt is made to cater for the predictability or unpredictability of wind power within this ‘standard’ year. Therefore, for example, 10 GW of wind capacity may generate 30 TWh per annum (i.e. 3000 full load hours, capacity/load factor 34%), so 4 GW of CCGT at 85% load factor produces the same annual generation as the 10 GW of wind. However, such conventional CCGT capacity may be viewed as delivering two services, energy production and reserve capacity.

Without capacity credit

If it is considered that wind can provide no contribution to capacity margin, then to be equivalent to conventional generation, wind would require back-up from generation equal to the *equivalent* conventional capacity. This capacity could come from a number of sources, including old conventional generation, new Combined Cycle Gas Turbine (CCGTs) or new Open Cycle Gas Turbines (OCGTs). Assume the capacity requirements are allocated at the price of new, but not leading-edge, OCGT suitable for peaking operation (i.e. at 55 €/kW/y)[11]. Then the cost of 4 GW of OCGT peaking capacity at 55 €/kW/yr is around €222m per annum (i.e. 7.39 €/MWh$_{\text{wind}}$), see Table 4.1.

With capacity credit

If it is considered that wind does contribute to system security, albeit at a lower proportion than conventional capacity, then the above capacity requirement is reduced by the amount of that contribution. If it is assumed that 25% of wind capacity (i.e. 2.5 GW of 10 GW) contributes to the system security, then the additional OCGT capacity requirement is reduced by this amount and now becomes 4 GW - 2.5 GW = 1.5 GW. At 55 €/kW/y the OCGT capacity cost is now €84m per annum (i.e. 2.80 €/MWh$_{\text{wind}}$), see Table 4.1.

Table 4.1 Example on the calculation of the additional capacity cost per MWh wind generation, with and without capacity credit (no presumptions made about the predictability of wind)

Example - Calculation of capacity cost		
Wind capacity	**10**	**GW**
Full load hours	**3000**	**h/y**
Wind generation	**30000**	**GWh**
Without capacity credit		
CCGT load factor	85	%
CCGT full load hours	7446	h/y
Thermal capacity equivalent	4	GW
Capacity credit wind	0	%
Capacity contribution wind	0	GW
Required thermal capacity	4	GW
Specific cost of thermal equivalent	55	€/kW/y
Capacity cost	222	million €
Capacity cost per MWh Wind	**7,39**	**€/MWh**
With capacity credit		
CCGT load factor	85	%
CCGT full load hours	7446	h/y
Thermal capacity equivalent	4	GW
Capacity credit wind	25	%
Capacity contribution wind	2,5	GW
Required thermal capacity	1,5	GW
Specific cost of thermal equivalent	55	€/kW/y
Capacity cost	84	million €
Capacity cost per MWh Wind	**2,80**	**€/MWh**

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[11] Assumption: investment cost: 420 €/kW; interest rate: 10%/y; depreciation time: 15 years.

Table 4.1 summarizes the two different approaches (*with* versus *without* capacity credit) of the example shown above.

System capacity cost for the UK case

In the following, the methodology of the calculation of additional system capacity cost is applied for the UK case, using different parameter values to demonstrate the bandwidth of the corresponding cost.

In a first approximate scenario for the year 2020, in Table 4.2, the capacity credit (average of onshore and offshore for winter and summer as well as annual average) for wind generation in the UK is shown. The capacity credit mainly depends on the installed wind capacity, the peak load in 2020 and also on the ratio of onshore and offshore.

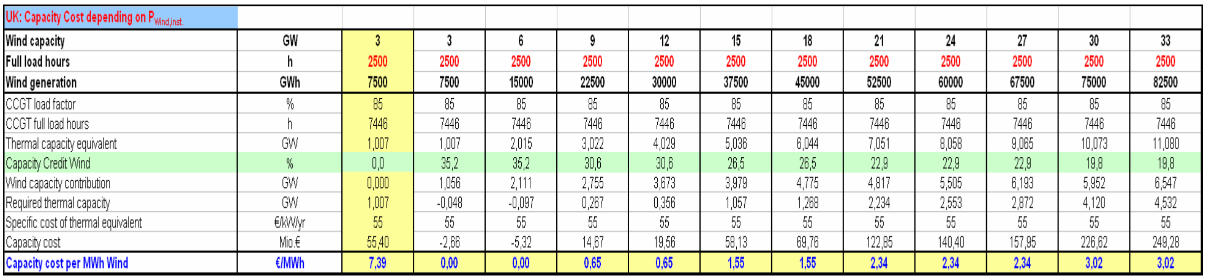
Table 4.2 Capacity credit for wind generation in the UK depending on the installed wind capacity and the assumption of a peak load increase factor 1.3 in the year 2020[12] (Ratio wind capacity Onshore:Offshore = 50%:50%).

Installed Wind Capacity GW	**$P_{Wind,inst}$ / $P_{L,max}$ %**	**Capacity Credit**		
		Winter	**Summer**	**Average**
3	4,4	50,8	19,5	35,2
6	8,7	50,8	19,5	35,2
9	13,1	44,2	17,1	30,6
12	17,4	44,2	17,1	30,6
15	21,8	38,2	14,9	26,5
18	26,1	38,2	14,9	26,5
21	30,5	32,9	12,9	22,9
24	34,8	32,9	12,9	22,9
27	39,2	32,9	12,9	22,9
30	43,5	28,4	11,3	19,8
33	47,9	28,4	11,3	19,8

UK - Assumptions: Onshore:Offshore = 50%:50%; $P_{Lmax(2002)}$ = 53,0 GW; Factor for peak load increase up to 2020: 1.3

The following tables show for the static UK case (year 2020) the additional system capacity cost depending on the installed wind capacity for different parameter settings based on the “thermal equivalent approach” presented in the *ILEX Energy Consulting Study (2002)*.

Table 4.3 Modelled additional capacity cost depending on the installed wind capacity in UK in 2020. Assumptions of the “thermal equivalent”: depreciation time 15 y, interest rate 10%/y, annualized capital cost 55 €/kW/y (investment cost 420 €/kW), load factor = 85% (7446 h/y). Ratio Onshore:Offshore = 50%:50%.



UK: Capacity Cost depending on $P_{Wind,inst.}$												
Wind capacity	**GW**	**3**	**3**	**6**	**9**	**12**	**15**	**18**	**21**	**24**	**27**	**30**	**33**
Full load hours	**h**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**
Wind generation	**GWh**	**7500**	**7500**	**15000**	**22500**	**30000**	**37500**	**45000**	**52500**	**60000**	**67500**	**75000**	**82500**
CCGT load factor	%	85	85	85	85	85	85	85	85	85	85	85	85
CCGT full load hours	h	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Thermal capacity equivalent	GW	1,007	1,007	2,015	3,022	4,029	5,036	6,044	7,051	8,058	9,065	10,073	11,080
Capacity Credit Wind	%	0,0	35,2	35,2	30,6	30,6	26,5	26,5	22,9	22,9	22,9	19,8	19,8
Wind capacity contribution	GW	0,000	1,056	2,111	2,755	3,673	3,979	4,775	4,817	5,505	6,193	5,952	6,547
Required thermal capacity	GW	1,007	-0,048	-0,097	0,267	0,356	1,057	1,268	2,234	2,553	2,872	4,120	4,532
Specific cost of thermal equivalent	€/kW/yr	55	55	55	55	55	55	55	55	55	55	55	55
Capacity cost	Mio.€	55,40	-2,66	-5,32	14,67	19,56	58,13	69,76	122,85	140,40	157,95	226,62	249,28
Capacity cost per MWh Wind	**€/MWh**	**7,39**	**0,00**	**0,00**	**0,65**	**0,65**	**1,55**	**1,55**	**2,34**	**2,34**	**2,34**	**3,02**	**3,02**

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[12] Source: National Grid Company (NGC); own investigations at EEG-Vienna

Table 4.4 Modelled additional capacity cost depending on the installed wind capacity in UK in 2020. Assumptions of the “thermal equivalent”: depreciation time 15 y, interest rate 13%/y, annualized capital cost 65 €/kW/y (investment cost 420 €/kW), load factor = 85% (7446 h/y). Ratio Onshore:Offshore = 50%:50%.

UK: Capacity Cost depending on $P_{Wind,inst.}$													
Wind capacity	**GW**	**3**	**3**	**6**	**9**	**12**	**15**	**18**	**21**	**24**	**27**	**30**	**33**
Full load hours	**h**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**
Wind generation	**GWh**	**7500**	**7500**	**15000**	**22500**	**30000**	**37500**	**45000**	**52500**	**60000**	**67500**	**75000**	**82500**
CCGT load factor	%	85	85	85	85	85	85	85	85	85	85	85	85
CCGT full load hours	h	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Thermal capacity equivalent	GW	1,007	1,007	2,015	3,022	4,029	5,036	6,044	7,051	8,058	9,065	10,073	11,080
Capacity Credit Wind	%	0,0	35,2	35,2	30,6	30,6	26,5	26,5	22,9	22,9	22,9	19,8	19,8
Wind capacity contribution	GW	0,000	1,056	2,111	2,755	3,673	3,979	4,775	4,817	5,505	6,193	5,952	6,547
Required thermal capacity	GW	1,007	-0,048	-0,097	0,267	0,356	1,057	1,268	2,234	2,553	2,872	4,120	4,532
Specific cost of thermal equivalent	€/kW/yr	65	65	65	65	65	65	65	65	65	65	65	65
Capacity cost	Mio.€	65,47	-3,14	-6,28	17,34	23,12	68,70	82,44	145,19	165,93	186,67	267,82	294,60
Capacity cost per MWh Wind	**€/MWh**	**8,73**	**0,00**	**0,00**	**0,77**	**0,77**	**1,83**	**1,83**	**2,77**	**2,77**	**2,77**	**3,57**	**3,57**

Table 4.5 Modelled additional capacity cost depending on the installed wind capacity in UK in 2020. Assumptions of the “thermal equivalent”: depreciation time 20 y, interest rate 7%/y, annualized capital cost 40 €/kW/y (investment cost 420 €/kW), load factor = 85% (7446 h/y). Ratio Onshore:Offshore = 50%:50%.

UK: Capacity Cost depending on $P_{Wind,inst.}$													
Wind capacity	**GW**	**3**	**3**	**6**	**9**	**12**	**15**	**18**	**21**	**24**	**27**	**30**	**33**
Full load hours	**h**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**
Wind generation	**GWh**	**7500**	**7500**	**15000**	**22500**	**30000**	**37500**	**45000**	**52500**	**60000**	**67500**	**75000**	**82500**
CCGT load factor	%	85	85	85	85	85	85	85	85	85	85	85	85
CCGT full load hours	h	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Thermal capacity equivalent	GW	1,007	1,007	2,015	3,022	4,029	5,036	6,044	7,051	8,058	9,065	10,073	11,080
Capacity Credit Wind	%	0,0	35,2	35,2	30,6	30,6	26,5	26,5	22,9	22,9	22,9	19,8	19,8
Wind capacity contribution	GW	0,000	1,056	2,111	2,755	3,673	3,979	4,775	4,817	5,505	6,193	5,952	6,547
Required thermal capacity	GW	1,007	-0,048	-0,097	0,267	0,356	1,057	1,268	2,234	2,553	2,872	4,120	4,532
Specific cost of thermal equivalent	€/kW/yr	40	40	40	40	40	40	40	40	40	40	40	40
Capacity cost	Mio.€	40,29	-1,93	-3,87	10,67	14,23	42,28	50,74	89,35	102,11	114,88	164,81	181,29
Capacity cost per MWh Wind	**€/MWh**	**5,37**	**0,00**	**0,00**	**0,47**	**0,47**	**1,13**	**1,13**	**1,70**	**1,70**	**1,70**	**2,20**	**2,20**

In Figures 4.1-4.3, different values are used in the “thermal equivalent approach” to assess the additional capacity cost due to large-scale wind integration under different constraints:

- In Figure 4.1, the additional capacity costs depending on the load factor of the thermal equivalent are shown for different scenarios of wind penetration in the UK in the year 2020. Two major effects can be observed: (i) increasing load factors of the thermal equivalent result in decreasing additional capacity cost, and (ii) increasing wind penetration in the system results in increasing additional capacity cost.
- In Figure 4.2, different assumptions on interest rates and depreciation periods of the “thermal equivalent” are shown for different scenarios of wind penetration in the UK in the year 2020. Again, two major effects can be observed: (i) increasing interest rates result in increasing additional capacity cost, and (ii) increasing depreciation periods result in decreasing additional capacity cost.
- Finally, in Figure 4.3, different assumptions about the onshore/offshore ratio of different scenarios of wind penetration in the UK in the year 2020 are discussed. Due to the larger average annual full load hours of offshore wind generation, additional capacity cost decrease with increasing shares of offshore wind generation (compared to onshore wind).[13]

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[13] Please note, compared to onshore wind generation, offshore wind generation has (i) higher average full load hours per unit capacity and (ii) more manageable operation options (e.g. due to active control).

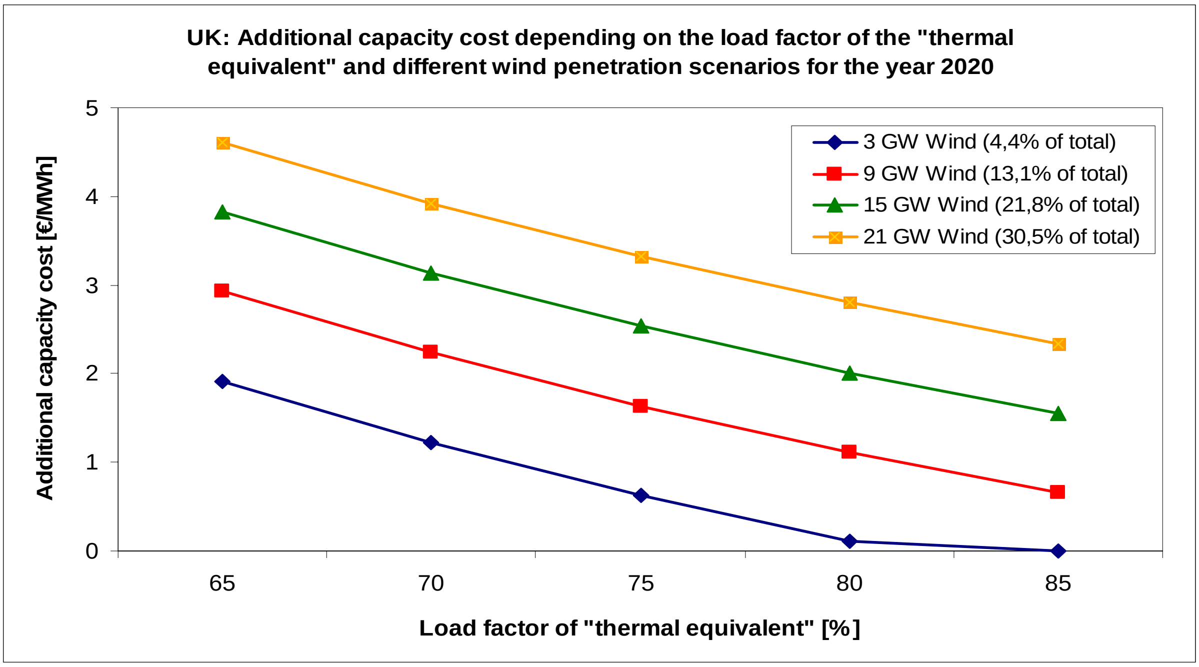

Figure 4.1 Additional capacity cost depending on the load factor of the “thermal equivalent” and different wind penetration scenarios for the year 2020. Assumptions of the “thermal equivalent”: depreciation time 15 y, interest rate 10%/y, annualized capital cost 55 €/kW/y (investment cost 420 €/kW), load factor = variable. Ratio Onshore:Offshore = 50%:50%.

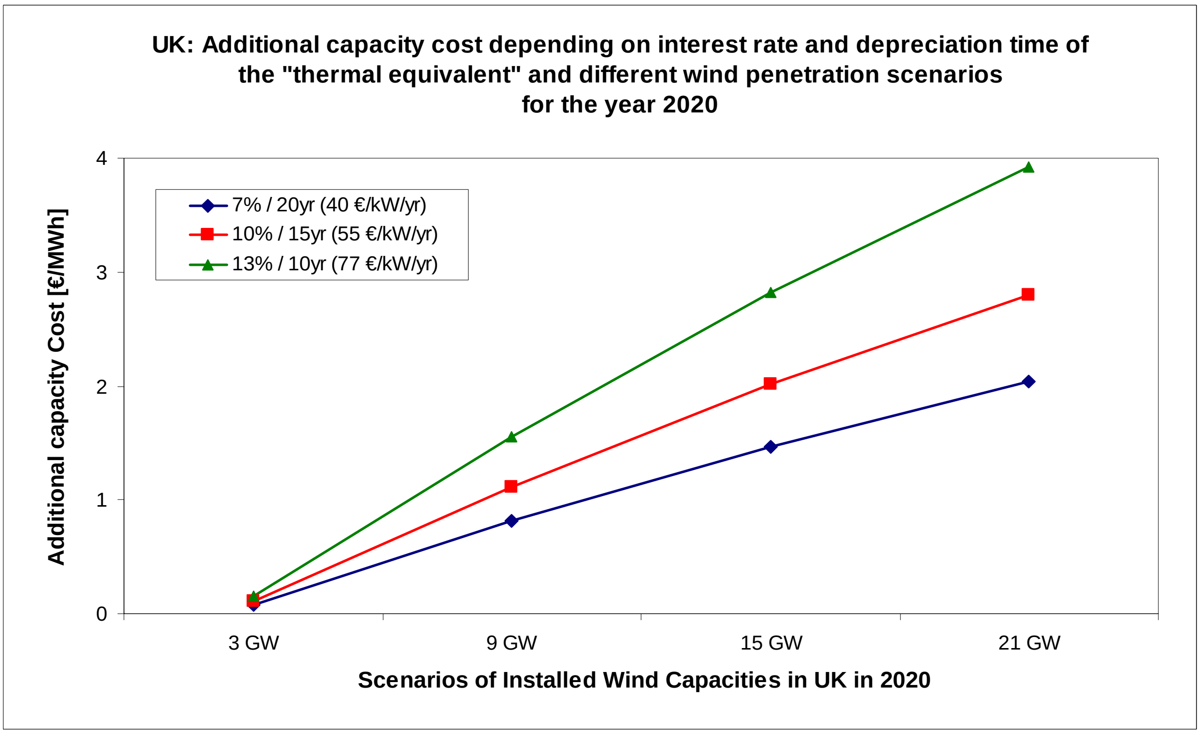

Figure 4.2 Additional capacity cost depending on the interest rate and depreciation time of the “thermal equivalent” and different wind penetration scenarios for the year 2020. Assumptions of the “thermal equivalent”: depreciation time: variable, interest rate: variable, annualized capital cost: variable (investment cost 420 €/kW), load factor = 80%. Ratio Onshore:Offshore = 50%:50%.

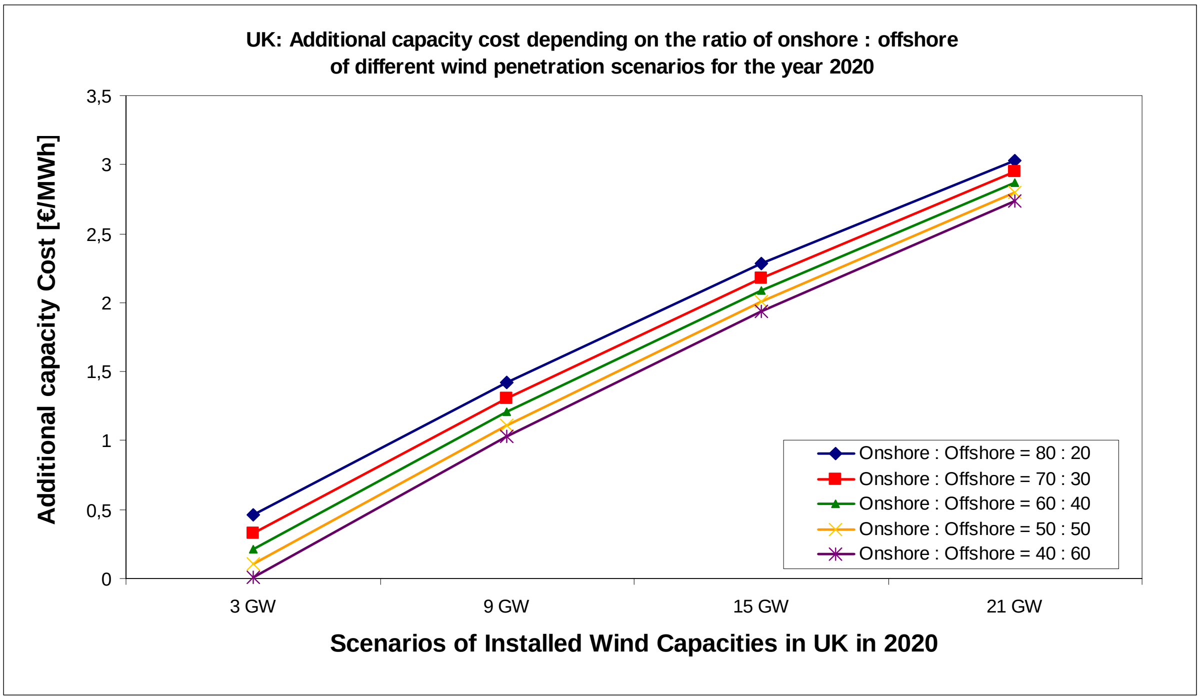

Figure 4.3 Additional capacity cost depending on the onshore/offshore ratio of different wind penetration scenarios for the year 2020. Assumptions of the “thermal equivalent”: depreciation time 15 y, interest rate 10%/y, annualized capital cost 55 €/kW/y (investment cost 420 €/kW), load factor = 80%. Ratio Onshore:Offshore = variable.

4.2 Additional system balancing cost (case study of wind power)

The requirement and cost of system balancing have been introduced in section 3.2.2. There have been few published analyses of ‘additional system balancing cost’ and there are few sources of suitable empirical data. For our purposes, there is a definite lack of information on balancing cost of wind power. Below we mainly refer to publications addressing the following countries: UK, Denmark, Germany and selected examples in U.S.

4.2.1 Correct allocation of additional system balancing cost

Balancing cost can be divided into two categories: (i) cost for reserve requirements and (ii) cost for online balancing energy in case reserve power plants are called.

The reserve requirement is determined within the dispatching process of the Transmission System Operator (TSO) being usually done at a specified time one day ahead of present scheduling. Therefore, after forecasting demand and generation, the operation of remaining power plants is optimised on merit order. To be able to handle deviations from forecasted demand and generation, power production of particular power plants is adapted depending on the actual condition of the system (demand exceeds generation or vice versa). Suitable technologies being qualified to contribute to balance the systems are thermal power plants running part-loaded, as well as gas turbines (OCGT or CCGT) and pump-storage-facilities being able to start up quickly when additional power is needed. Note, when running thermal power plants part-loaded, the efficiency is decreased which leads to additional operation costs. Note further, the operation of gas turbines is very cost intensive (due to higher variable cost compared to other technologies). To minimise the additional cost for system operation the trade-off of these two options for balancing the system has to be determined. In this report, cost for reserve requirements are considered to be part of the so-called "additional capacity costs". Therefore, they are not part of the balancing costs as it may be the case in other publications.

The so called "balancing energy" is energy being "delivered" or "withheld" by reserve power plants. Cost occurring when operating reserve power plants, are called "balancing cost" in this report. The requested amount of balancing energy is, in principle, driven by the overall forecast uncertainty of both supply and demand. As there is no evidence that the individual fluctuations on supply and demand are correlated, the resulting deviation is less than the sum of the individual components. This means that the different deviations compensate each other to a certain extent and impact on the additional balancing cost.

Therefore, when determining the additional balancing requirements due to wind power, only the additional deviation compared to a system without wind has to be taken into account, but not the total wind forecast error. Figure 4.4 illustrates the combination of the different relevant forecast errors for a power system. The most important aspect is that the resulting forecast error is less than the sum of the individual categories considered.

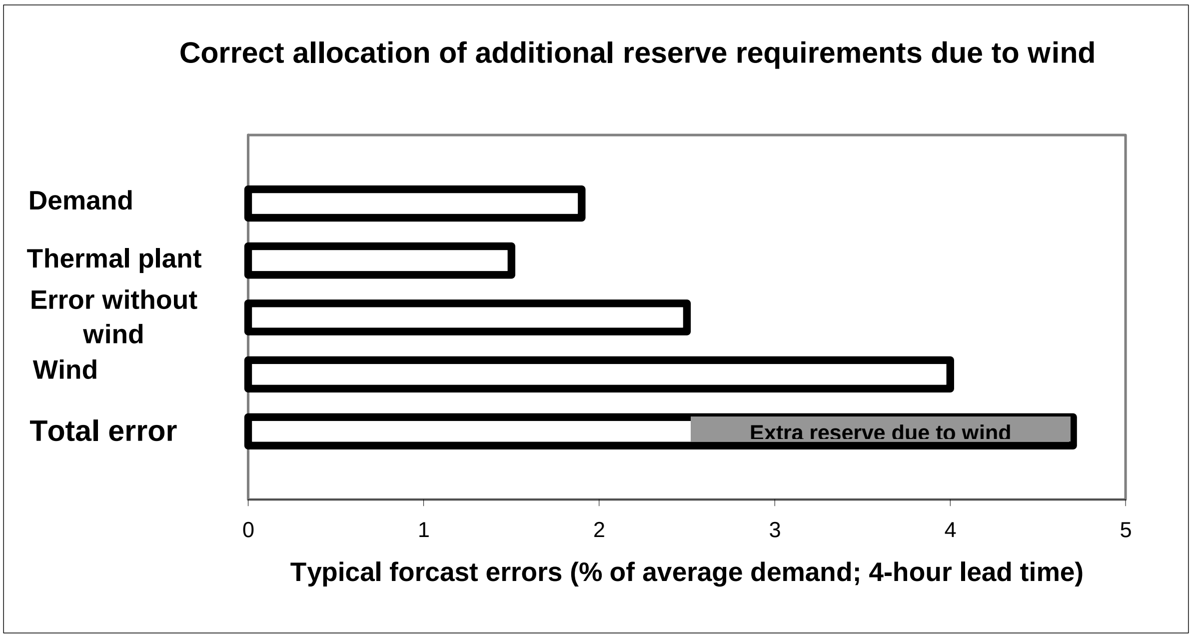

Figure 4.4 Correct allocation of additional reserve requirements caused by wind integration. Source: Milborrow (2004).

4.2.2 Country-specific studies on additional system balancing cost

The following section summarises the most important existing country-specific case studies on additional system balancing cost due to large-scale intermittent wind integration (see also comparisons in Table 4.5 and Figure 4.5).

UK – ILEX/UMIST (2002)

ILEX Energy Consulting (2002) estimates the additional cost (based on a baseline scenario) due to an increase of RES-E generation in the system up to 2020. Two major wind scenarios exist (20% and 30% RES-E deployment). The corresponding additional balancing cost allocated to wind are 1.28 £/MWh (20%) and 1.88 £/MWh (30%). For a detailed disaggregated allocation of the additional balancing cost it is referred to the cited study.

DK – Morthorst (2002)

Morthorst (2002) analyses the balancing cost in the Jutland/Funen region in Western Denmark (grid operator Eltra) based on time series of wind generation. Eltra operated in 2002 around 20% wind generation in the system (i.e. around 60% installed wind capacity compared to system peak load). This is the system with utmost wind generation worldwide. The average balancing cost allocated to wind generation only are determined with around 3 €/MWh.

DE – Elsässer (2003)

In Germany installed wind generation was 8750 MW by the end of 2001 (i.e. around 7,5% of installed wind capacity compared to system peak). For cited wind penetration E.ON Grid calculates around 7 €/MWh on cost for system balancing. Another 15 €/MWh are allocated to system capacity. These are by far the largest additional system operation cost due to wind integration published. In the recently published study Dena (2005) lower system balancing cost are determined. For a detailed discussion of Dena (2005) it is referred to section 5 below.

U.S. – Xcel Energy

The grid operator Xcel Energy investigated the impact of a 280 MW windfarm in Minnesota (peak load of 8000 MW in summer). Using conservative assumptions, the additional system balancing cost allocated to additional wind generation are determined by 0.41 $/MWh (i.e. about 0.35 €/MWh).

U.S. – PacifiCorp

PacifiCorp (located in the North West of the U.S.; peak load 8300 MW) intents to increase wind penetration to 14% in the next 10 years (i.e. 1400 MW installed wind capacity). A variety of case studies exist for different degrees of wind penetration. For 20% wind penetration (planned beyond 2020) additional system operation cost of 5.5 $/MWh (5 €/MWh) are published in total, whereas around 2.5 $/MWh are allocated to system capacity requirements to maintain system security. Around 3 $/MWh (about 2.4 €/MWh) are allocated to short-term system balancing due to wind integration.

U.S. – Bonneville Power Administration (BPA)

For 1000 MW installed wind generation in the Bonneville Power Administration supply area (located in the North West of the U.S.; hydro-power dominated generation; peak load 14000 MW)) additional total system balancing cost of 1.0-1.8 $/MWh (0.8 to 1.5 €/MWh) are published (see e.g. also Hirst (2002)).

U.S. – We Energies

The WeEnergies supply area is located in Wisconsin (incl. the northern part of the Michigan peninsula) and is characterised by a system peak load of around 6000 MW (summer) and a conventional power plant mix dominated by coal fired and nuclear power plants. Analyses exist on the additional cost of different scenarios of wind integration (between 250 and 2000 MW) up to 2012. The total additional system operation cost (balancing as well as reserve) allocation to wind only are estimated 2-3 $/MWh (1.8 to 2.7 €/MWh) (note, load uncertainties are large in the WeEnergies supply area).

Table 4.5 Summary of the results on international studies on additional system balancing cost due to large-scale intermittent wind integration.

Study	$P_{L,max}$	$P_{Wind,inst}$	Time Horizon	$P_{Wind,inst}$ / $P_{L,max}$	Balancing cost
	MW	MW	year	%	€/MWh
UWIG/Xcel	800	280	2003	3,5	0,3
PacifiCorp	8300	1400	2013	20	2,0
BPA	14000	1000	2002	7	0,4
We Energies 1	7000	250	2012	4	1,0
We Energies 2	7000	2000	2012	29	0,9
Risoe	3800	2280	2002	60	3,0
Consentec	9000	700	2008	7,8	10,7
E.ON	30000	6000	2002	20	7,0
ILEX 20%	75700	24000	2020	18,7	1,8
ILEX 30%	75700	38000	2020	37,2	2,7

International studies on balancing cost allocated to large-scale wind integration

1 Pound Sterling = 1,42 Euro; 1 US Dollar = 0,79 Euro (1 Jan 2004)

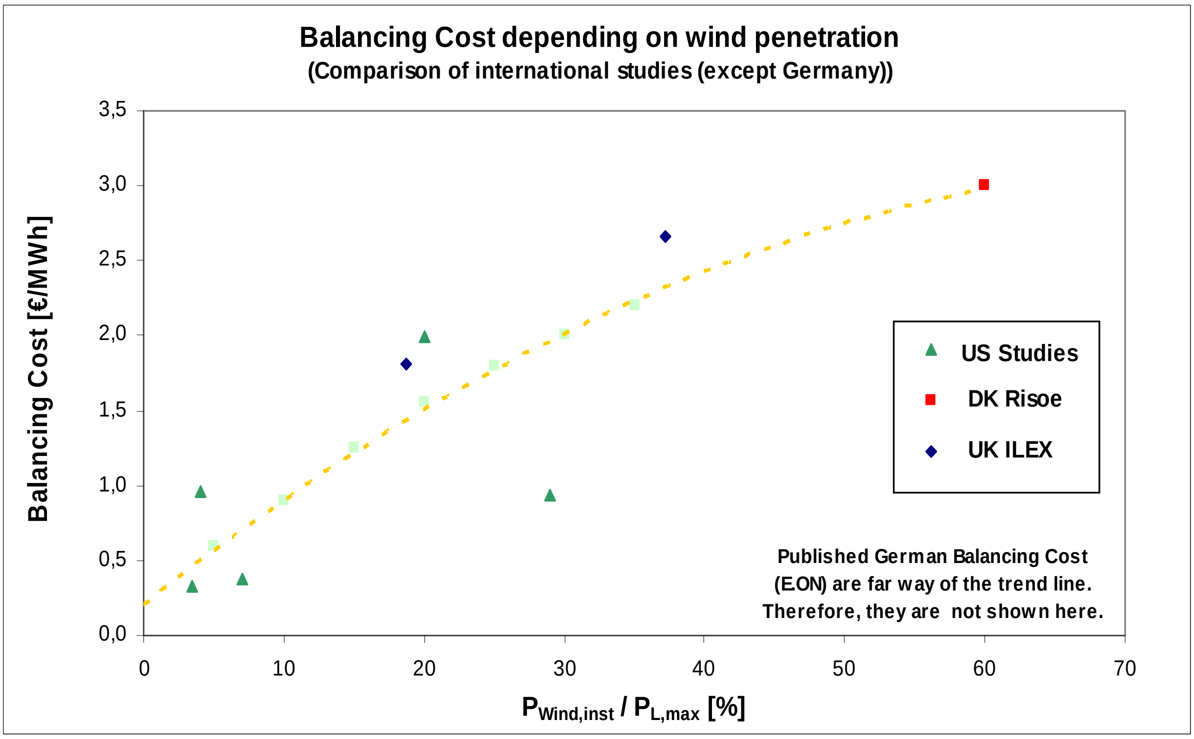

Figure 4.5 Comparison of international studies on additional balancing cost due to large-scale intermittent wind integration.

4.3 Total additional system operation cost (case study of wind power)

The total additional system operation cost due to large-scale intermittent wind integration in a system is the sum of the corresponding

- additional system capacity cost (see section 4.1 above) and
- additional system balancing cost (see section 4.2 above).

Based on the empirical results shown in sections 4.1 and 4.2 it can be concluded that – as a rough estimate regardless of the particular features of a system – total additional system operation cost are:

- below 5% (i.e. around 2-4 €/MWh_{wind}) of the long-run marginal cost of wind generation for small wind penetrations in a system (<10% penetration),
- up to 10% (i.e. around 5-6 €/MWh_{wind}) of the long-run marginal cost of wind generation for high wind penetrations in a system (>20% penetration).

5 ADDITIONAL GRID REINFORCEMENT/EXTENSION COST ALLOCATED TO RES-E GENERATION

5.1 Overview

The following country-specific studies quantify grid reinforcement/extension requirements and corresponding cost caused by a variety of factors. These factors include requirements for increases in generation to meet demand (in general) and necessary measures and cost for large-scale wind integration (in particular). The comprehensive analyses shown below are based on load flow simulations of the corresponding national transmission and distribution grids taking into account different scenarios of national wind integration, utilising the most favourable sites.

The country-specific studies shown in Table 5.1 and Figure 5.1 indicate that the grid reinforcement/extension cost caused by additional wind generation are in the range of 0.1 to 5 €/MWh$_{wind}$, depending in the wind penetration in a system. Note, these are first clues in this particular field of research and much more studies and a harmonisation of the method is needed to conduct a reliable empirical relation between grid reinforcement/extension cost and wind energy penetration. It may, however, serve to identify problems with studies yielding results far from the present results.

Table 5.1 Country-specific studies quantifying grid reinforcement/extension measures and corresponding cost caused by additional wind generation. The table gives the estimated grid extension/reinforcement costs expressed in € per MWh$_{wind}$. Sources: see reference list in the right column.

Empirical Data based on Country Studies			
Country	**Wind generation (Share in % of total)**	**Grid Extension Cost €/MWh**	**Reference**
Belgium I	1,3%	0,10	van Roy et al (2003)
Belgium II	1,8%	0,20	van Roy et al (2003)
Austria I	2,1%	0,30	Consentec et al (2003), EEG (2003), Haidvogl (2001)
Austria II	2,9%	0,30	Consentec et al (2003), EEG (2003), Haidvogl (2001)
Austria III	6,4%	0,40	Consentec et al (2003), EEG (2003), Haidvogl (2001)
France	8,1%	1,60	Verseille (2003)
Germany I	9,0%	1,00	Fuchs (2003)
Poland I	14,1%	1,40	Janiczek et al (2003)
Germany II	16%	2,00	Elässer (2003)
Poland II	16,1%	1,60	Janiczek et al (2003)
Netherlands	16,6%	1,60	t Hooft (2003)
UK I	20%	3,30	ILEX / UMIST (2002)
UK II	30%	4,70	ILEX / UMIST (2002)
Germany DENA	*Onshore only*		DEWI et al (2005)
	7%	0,51	
	11%	0,88	
	14%	0,96	
	Onshore + Offshore		
	11%	3,84	
	14%	5,27	

Note: The recently published Dena Study (February 2005) comprehensively investigates wind integration in Germany up to 2020. Comparing the Dena (2005) results for Germany with the “old” data addressing the E.ON supply area only (Elsässer (2003), Fuchs (2003), Luther (2001)), virtually the same wind specific grid reinforcement/ extension cost (around 2 €/MWh$_{wind}$) for the 2015 German wind penetration scenario (being comparable in several publications) are derived. Details in this context are discussed in the German section below.

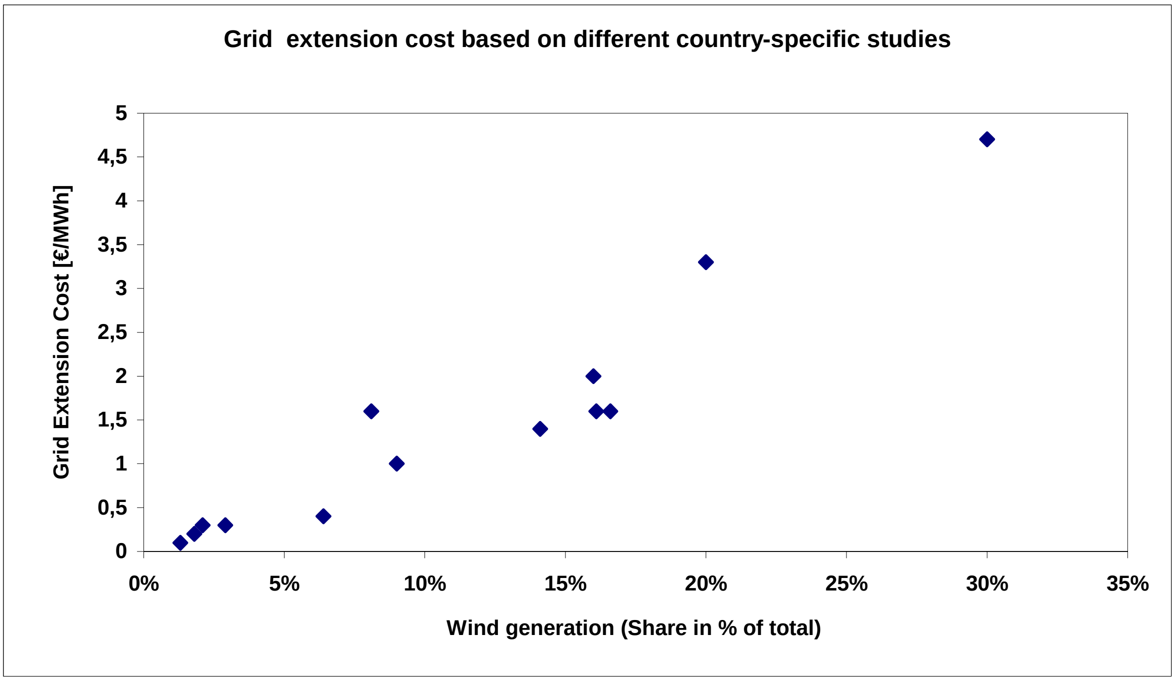

Figure 5.1 Country-specific studies quantifying grid reinforcement/extension measures and corresponding cost caused by additional wind generation. Sources: see Table 5.1 above.

5.2 Selected country studies

5.2.1 UK (incl. Scotland)

Study

ILEX Energy Consulting & UMIST: “Quantifying the System Cost of Additional Renewables in 2020”, A report of Department of Trade & Industry and Manchester Centre for Electrical Energy, UMIST, October 2002.

Summary of results

Referring to the additional transmission and distribution cost presented especially for the *North Wind Scenarios* (Share Offshore:Onshore = 50:50) the following empirical data have been derived, given conventional criteria for lifetime, operation and management etc:

- 20% wind generation: 3,3 €/MWh transmission & distribution grid extension cost
- 30% wind generation: 4,7 €/MWh transmission & distribution grid extension cost

Remarks

Results are based on comprehensive load flow analyses on the UK transmission and distribution grid for different scenarios of wind penetration up to 2020. The cost of power sold to the ordinary UK consumer is about £80/MWh, i.e. 130€/MWh, not including any carbon-abatement criteria. Therefore wind farm interconnection costs represent about 2.5 to 3.5% of user cost, which is not significantly different from similar costs for new major central generation. It is important to note, however, that such cost occur for all generation and are not significant extras of RES-E generation only.

5.2.2 Germany

Study

1. *Dena (2005):* “Energiewirtschaftliche Planung für die Netzintegration von Windenergie in Deutschland an Land und Offshore bis zum Jahr 2020”, Studie im Auftrag der Deutschen Energie-Agentur GmbH (dena), Konsortium: DEWI, E.ON Netz, EWI, RWE Net, VE Transmission, Februar 2005.
2. *Elsässer (2003),* E.ON: “Kosten der Windenergienutzung in Deutschland”, Präsentation im Rahmen der Sitzung des Wirtschaftsbeirates der Union, Berlin, 23 Juli 2003.
3. *Fuchs (2003),* E.ON: „Wind power in Germany – Present situation and outlook“, CEO E.ON Netz, 23 January 2003.

Summary of results

- *Dena (2005):* Different wind penetration scenarios in Germany (onshore and offshore) are presented in detail for the years 2007, 2010 and 2015. Concerning grid extension/reinforcement of the existing German onshore transmission grid finally additional 850 km are necessary in the 2015 scenario (assuming installed capacity of 36 GW wind in total, whereas 26,2 GW wind onshore). Total installed wind capacity of 36 GW is assumed to generate 77,2 TWh in 2015. The corresponding costs for the extension/reinforcement of the additional 850 km of the onshore transmission grid are around €1,1bn. These are around 2 €/MWh$_{\text{wind}}$ if the total cost are allocated to wind generation proportionally (i.e. around 13% out of total generation in Germany in 2015).
- *Elsässer (2003):* For a scenario of around 16% wind generation in the E.ON supply area (15 GW onshore, 15 GW offshore by 2016) in Germany, Elsässer (2003) suggests around 2 €/MWh for grid extension/reinforcement cost of the existing transmission grid. This amount occurs mainly because significant offshore wind generation has to be transported to the intensive demand areas in the interior of the country (the transmission and distribution grid currently is not sufficiently for that purpose, being designed with central generation located as near as possible to urban demand).
- *Fuchs (2003):* He refers to the additional grid extension/reinforcement cost of the existing grid mainly due to 15 GW offshore wind energy. Published data (550 €m cumulated, 15 GW, 3,000 full load hour/y (i.e. load capacity factor 34%), depreciation 25 years, interest rate 5%); final conclusion that the grid extension/reinforcement cost would be 1 €/MWh for 15 GW offshore wind only (i.e. share of 9% of total wind generation).

Remarks

The recently published Dena (2005) study addresses the entire Germany region, not only a particular supply area (like the E.ON publications from Elsässer (2003) and Fuchs (2003)). Most important, however, is that both Dena (2005) and Elsässer/Fuchs (2003) derive virtually the same wind related grid extension/reinforcement cost of the existing transmission grid (around 2 €/MWh$_{\text{wind}}$) in Germany for the 2015 (Dena) and 2016 (Elsässer/Fuchs) wind penetration scenarios respectively.

5.2.3 France

Study

Jean Verseille: “Growth and Grids – Panel discussion on issues of grid extension, supply predictability and power quality”, Proceedings: European Wind Energy Conference 2003, Madrid, 16-19 June 2003.

Summary of results

According to Verseille (2003), the French national transmission and distribution grid could cope with 6 GW of wind power capacity with only minor development work; however if the capacity were to grow 14 GW it would cost €800-million to improve the network. This would be for annual wind generation of 35 TWh (8.1% of total French generation), i.e. 1,9 €/MWh wind generation allocated to grid extension.

Remarks

No particular remarks are available since wind penetration in France is still on a very early stage.

5.2.4 Netherlands

Study

Jaap `t Hooft, Novem: “Survey of integration of 6000 MW offshore wind power in the Netherlands electricity grid in 2020“, NOVEM, 2003.

Summary of results

The major objective was to analyze the technical, organizational, financial and administrative-legal consequences of integration of 6 GW offshore wind in the Netherlands electricity grid and, subsequently, the financial consequences for those involved. Integration of corresponding offshore wind capacity into the Dutch grid by 2020 would results in 16.6% of total national consumption being from wind generation. The estimated total cost for reinforcement of the existing grid on land and for offshore grid connection are around €413m for a medium cost scenario according to ‘t Hooft (2003). Consequently, the additional grid extension/reinforcement cost for offshore wind integration would be around 1.6 €/MWh, see Table 5.1.

Remarks

Different grid connection scenarios for offshore wind (including all associated measures and cost) have been analyzed in detail. The cost range of these grid connection scenarios are between M€274 and M€564 (i.e. about 1.1 to 2.2 €/MWh of wind generation).

5.2.5 Belgium

Study

Univ. Leuven: “Impact of the wind generation on the Belgian high voltage grid”, Department of Electrical Engineering ESAT/ELECTA, 2003.

Summary of results

The major results of this comprehensive study can be summarized as: (i) up to 100 MW of wind capacity, no grid reinforcement measures and costs occur, (ii) up to 350 MW, one line is congested in particular (Slijkens-Brugge), (iii) up to 500 MW, (and beyond) a new connection line is needed (Koksijde-Slijkens). For a scenario of an installed wind capacity of 350 MW (1.05 TWh wind generation, i.e. 1,3% of total generation), an additional cost of 0.1 €/MWh is allocated for grid extension. For a scenario of an installed wind capacity of 500 MW (1.5 TWh wind generation, i.e. 1.8% of total generation), an additional cost of 0,2 €/MWh is allocated for grid extension, see Table 5.1.

Remarks

Rather limited amounts of offshore wind power can be integrated into the grid in Belgium. In this context it must be stressed that the possible case of line overload and (N-1)-uncertainty (which descries redundancy of the intermeshed system if a single line fails) not only concern offshore wind power integration but are also a result of: (i) the existing net flow from West Flanders to the Antwerp-Brussels region and (ii) cross-border power transits.

5.2.6 Austria

Study

This summary is based on the following references:

- Consentec, RTWH Aaachen, FGH-Mannhein: „Auswirkungen des Windkraftausbaus in Österreich", Studie von Consentec Consultung für Energiewirtschaft und –technik GmbH, Institut für Elektrische Anlagen und Energiewirtschaft der RWTH Aachen, Forschungsgemeinschaft für Elektrische Anlagen und Stromwirtschaft im Auftrag der E-Control GmbH, Schlussbericht, Wien, Juni 2003.
- Haidvogl Herbert: "Netzanbindung von Windenergieerzeugungsanlagen (WEA)", Elektrizitätswirt-schaft, S. 20-21, 2002.

Summary of results

For Austria, different scenarios of wind integration are simulated for the year 2008 (according to the expected range of installed wind capacity in the national electricity law). For the lower bound of 576 MW installed wind capacity (i.e. 2.1% of national power from wind generation) in the year 2008, grid extension cost allocated to wind is calculated to be 0.3 €/MWh. For the upper bound expected in the year 2008 of 800 MW installed wind capacity (i.e. 2.9% wind generation), a slightly larger value is derived. For an assumption of an installed wind capacity of 1700 MW in the year 2020 (6.4% wind generation), additional grid extension/reinforcement cost for wind are calculated to be 0,4 €/MWh.[14]

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[14] In Austria, there has been a debate about the need for major transmission grid reinforcement for many years or even decades; this is not just for wind integration, but for all supplies. A suggestion is for an open loop on the 380kV-level between Südburgenland-Kainachtal (around 70km). The proposed costs are around €120 million. Note, that only parts of these costs can be allocated to wind generation, since this transmission line is strategically important anyway for the conventional electricity markets in the next decades.

5.2.7 Poland

Study

Polish Power Grid Company, Gdansk Institute of Power Engineering: ”Study of Integration Possibilities of Wind Energy with the Polish Power Grid”, Proceedings: European Wind Energy Conference 2003, Madrid, 16-19 June 2003.

Summary of results

Based on this Polish study, no reinforcement in the network is necessary for up to 2.8 GW of installed wind capacity. From 2.8 GW to 4 GW, a few upgrades on the Polish transmission grid would be necessary (e.g. new EHV/110kV transformers). Between 4GW to-5 GW installed wind capacity (and corresponding wind generation) difficulties could occur, especially in off-peak summer days, without using export and hydro storage facilities. Between 5 GW to 7 GW, a new 400 kV transmission line connecting the northern grid (where most wind generation would be located) with central Poland would be necessary. Beyond 8 GW installed wind capacity, a second 400 kV transmission circuit would have to be installed between the northern grid and the centre of the country.

Remarks

In the study cited, substantial investments are identified for large-scale wind integration in Poland. We note that generation in Poland is very dependent now on coal-fired plant, which will be unacceptable for EU CO_2 limitation policies.

6 EXCERPT OF THE DATA BASE ON RES-E GRID INTEGRATION COST IN GREENNET-EU27

As already mentioned in previous chapters the data base on the cost of RES-E grid integration consists of both technology-specific as well as country-specific data.

- The *grid connection cost* are technology-specific. For each of the RES-E technologies addressed a particular value (share in % of the long-run marginal cost) is already integrated into the data base.
- The *grid reinforcement/extension cost* are also technology-specific; more precisely: wind-specific. Derived from country-specific studies the grid reinforcement/extension cost are clustered depending on the share of wind generation (in % of total generation).
- The *system operation cost* (balancing and capacity cost) are modelled both country-specific as well as wind-specific.

6.1 Grid connection cost

The grid connection cost are technology-specific. They are already incorporated into the long-run marginal cost of RES-E technologies in the data base.

6.2 Grid reinforcement/extension cost

Based on the existing empirical data derived from different country-specific studies in the simulation software **Green*Net*** the grid reinforcement/extension cost are modeled depending on the share of wind generation (in % of total) indicated in Figure 6.1 below.

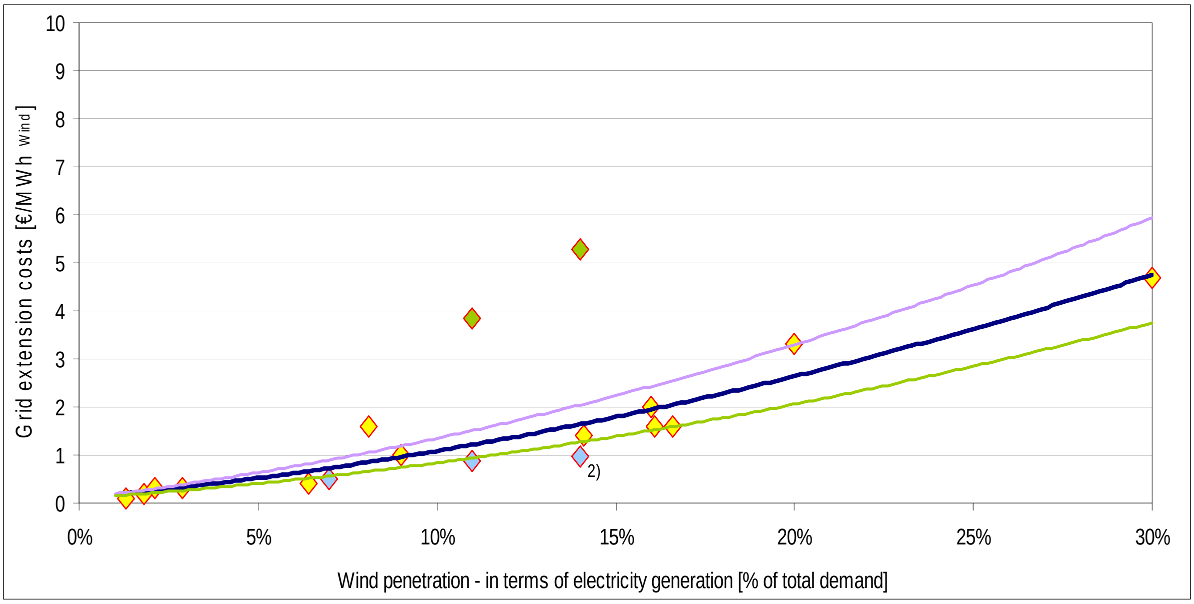

Figure 6.1 Modelling grid reinforcement/extension cost in the project **Green*Net*** depending on the share of wind generation (in % out of total).

6.3 System operation cost

The system operation cost (balancing and capacity cost) are modelled both country-specific as well as wind-specific. Below the system operation cost (balancing and capital cost) are documented for a particular case[15] on country-level depending on the installed wind capacity in selected EU Member States (details on several EU27 countries see in the corresponding data base (Deliverable D4a on the project website www.greennet-europe.org)).

6.3.1 Germany

GERMANY	Input Area	
Peak load 2002 (GW); Load increase factor for 2020	75,8	1,3
Ratio Onshore : Offshore	50	50
Full load hours Onshore; Offshore	2000	3000
Full load hours Weighted		2500
CCGT load factor (%); Annualised cost (€/kW/yr)	85	55

Installed Wind Capacity GW	PWind,inst / PL,max %	Capacity Credit		
		Winter	Summer	Average
5	5,1	50,8	19,5	35,2
10	10,1	44,2	17,1	30,6
15	15,2	44,2	17,1	30,6
20	20,3	38,2	14,9	26,5
25	25,4	38,2	14,9	26,5
30	30,4	32,9	12,9	22,9
35	35,5	32,9	12,9	22,9
40	40,6	28,4	11,3	19,8
45	45,7	28,4	11,3	19,8

Average											
Wind capacity	**GW**	**5**	**5**	**10**	**15**	**20**	**25**	**30**	**35**	**40**	**45**
Full load hours	**h**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**
Wind generation	**GWh**	**12500**	**12500**	**25000**	**37500**	**50000**	**62500**	**75000**	**87500**	**100000**	**112500**
CCGT load factor	%	85	85	85	85	85	85	85	85	85	85
CCGT full load hours	h	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Thermal capacity equivalent	GW	1,679	1,679	3,358	5,036	6,715	8,394	10,073	11,751	13,430	15,109
Capacity Credit Wind	%	0,0	35,2	30,6	30,6	26,5	26,5	22,9	22,9	19,8	19,8
Wind capacity contribution	GW	0,000	1,759	3,061	4,592	5,306	6,632	6,882	8,028	7,936	8,928
Required thermal capacity	GW	1,679	-0,081	0,296	0,445	1,409	1,762	3,191	3,723	5,494	6,180
Specific cost of thermal equivalent	€/kW/yr	55	55	55	55	55	55	55	55	55	55
Capacity cost	Mio.€	92,33	-4,43	16,30	24,45	77,51	96,89	175,51	204,76	302,16	339,92
Capacity cost per MWh Wind	**€/MWh**	**7,39**	**0,00**	**0,65**	**0,65**	**1,55**	**1,55**	**2,34**	**2,34**	**3,02**	**3,02**
Balancing cost per MWh Wind	**€/MWh**	**3,69**	**0,00**	**0,33**	**0,33**	**0,78**	**0,78**	**1,17**	**1,17**	**1,51**	**1,51**
Capacity & Balancing cost per MWh Wind	**€/MWh**	**11,08**	**0,00**	**0,98**	**0,98**	**2,33**	**2,33**	**3,51**	**3,51**	**4,53**	**4,53**

6.3.2 Denmark

DENMARK	Input Area	
Peak load 2002 (GW); Load increase factor for 2020	6,1	1,3
Ratio Onshore : Offshore	50	50
Full load hours Onshore; Offshore	2000	3000
Full load hours Weighted		2500
CCGT load factor (%); Annualised cost (€/kW/yr)	85	55

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[15] Note, that for different countries for the year 2020 different ratios of onshore / offshore are assumed (taking into account current country-specific discussions on offshore deployment up to 2020). Furthermore, for the "thermal equivalent" (see chapter 4.1 in detail) a load factor of 85% and annualised capital cost of 55 €/kW/yr (i.e. investment cost of 420 €/kW, 10% interest rate, 15 year depreciation) are used.

Installed Wind Capacity	PWind,inst / PL,max	Capacity Credit		
GW	%	Winter	Summer	Average
0,375	4,7	50,8	19,5	35,2
0,750	9,5	50,8	19,5	35,2
1,125	14,2	44,2	17,1	30,6
1,500	18,9	44,2	17,1	30,6
1,875	23,6	38,2	14,9	26,5
2,250	28,4	38,2	14,9	26,5
2,625	33,1	32,9	12,9	22,9
3,000	37,8	32,9	12,9	22,9
3,375	42,6	28,4	11,3	19,8
3,750	47,3	28,4	11,3	19,8

Average												
Wind capacity	**GW**	**0,375**	**0,375**	**0,75**	**1,125**	**1,5**	**1,875**	**2,25**	**2,625**	**3**	**3,375**	**3,75**
Full load hours	**h**	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500
Wind generation	**GWh**	**937,5**	**937,5**	**1875**	**2812,5**	**3750**	**4687,5**	**5625**	**6562,5**	**7500**	**8437,5**	**9375**
CCGT load factor	%	85	85	85	85	85	85	85	85	85	85	85
CCGT full load hours	h	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Thermal capacity equivalent	GW	0,126	0,126	0,252	0,378	0,504	0,630	0,755	0,881	1,007	1,133	1,259
Capacity Credit Wind	%	0,0	35,2	35,2	30,6	30,6	26,5	26,5	22,9	22,9	19,8	19,8
Wind capacity contribution	GW	0,000	0,132	0,264	0,344	0,459	0,497	0,597	0,602	0,688	0,670	0,744
Required thermal capacity	GW	0,126	-0,006	-0,012	0,033	0,044	0,132	0,159	0,279	0,319	0,464	0,515
Specific cost of thermal equivalent	€/kW/yr	55	55	55	55	55	55	55	55	55	55	55
Capacity cost	Mio €	6,92	-0,33	-0,66	1,83	2,45	7,27	8,72	15,36	17,55	25,49	28,33
Capacity cost per MWh Wind	**€/MWh**	**7,39**	**0,00**	**0,00**	**0,65**	**0,65**	**1,55**	**1,55**	**2,34**	**2,34**	**3,02**	**3,02**
Balancing cost per MWh Wind	**€/MWh**	**3,69**	**0,00**	**0,00**	**0,33**	**0,33**	**0,78**	**0,78**	**1,17**	**1,17**	**1,51**	**1,51**
Capacity & Balancing cost per MWh Wind	**€/MWh**	**11,08**	**0,00**	**0,00**	**0,98**	**0,98**	**2,33**	**2,33**	**3,51**	**3,51**	**4,53**	**4,53**

6.3.3 Spain

SPAIN	Input Area	
Peak load 2002 (GW); Load increase factor for 2020	33,2	1,3
Ratio Onshore : Offshore	80	20
Full load hours Onshore; Offshore	2000	3000
Full load hours Weighted		2200
CCGT load factor (%); Annualised cost (€/kW/yr)	85	55

Installed Wind Capacity	PWind,inst / PL,max	Capacity Credit		
GW	%	Winter	Summer	Average
2	4,6	42,1	17,0	29,6
4	9,3	42,1	17,0	29,6
6	13,9	36,4	15,0	25,7
8	18,5	36,4	15,0	25,7
10	23,2	31,3	13,3	22,3
12	27,8	31,3	13,3	22,3
14	32,4	26,9	11,7	19,3
16	37,1	26,9	11,7	19,3
18	41,7	23,0	10,4	16,7
20	46,3	23,0	10,4	16,7

Average												
Wind capacity	**GW**	**2**	**2**	**4**	**6**	**8**	**10**	**12**	**14**	**16**	**18**	**20**
Full load hours	**h**	2200	2200	2200	2200	2200	2200	2200	2200	2200	2200	2200
Wind generation	**GWh**	**4400**	**4400**	**8800**	**13200**	**17600**	**22000**	**26400**	**30800**	**35200**	**39600**	**44000**
CCGT load factor	%	85	85	85	85	85	85	85	85	85	85	85
CCGT full load hours	h	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Thermal capacity equivalent	GW	0,591	0,591	1,182	1,773	2,364	2,955	3,546	4,136	4,727	5,318	5,909
Capacity Credit Wind	%	0,0	29,6	29,6	25,7	25,7	22,3	22,3	19,3	19,3	16,7	16,7
Wind capacity contribution	GW	0,000	0,591	1,183	1,543	2,057	2,229	2,675	2,700	3,085	3,006	3,340
Required thermal capacity	GW	0,591	0,000	-0,001	0,230	0,306	0,726	0,871	1,437	1,642	2,312	2,569
Specific cost of thermal equivalent	€/kW/yr	55	55	55	55	55	55	55	55	55	55	55
Capacity cost	Mio €	32,50	-0,02	-0,05	12,63	16,84	39,91	47,89	79,02	90,30	127,17	141,30
Capacity cost per MWh Wind	**€/MWh**	**7,39**	**0,00**	**0,00**	**0,96**	**0,96**	**1,81**	**1,81**	**2,57**	**2,57**	**3,21**	**3,21**
Balancing cost per MWh Wind	**€/MWh**	**3,69**	**0,00**	**0,00**	**0,48**	**0,48**	**0,91**	**0,91**	**1,28**	**1,28**	**1,61**	**1,61**
Capacity & Balancing cost per MWh Wind	**€/MWh**	**11,08**	**0,00**	**0,00**	**1,44**	**1,44**	**2,72**	**2,72**	**3,85**	**3,85**	**4,82**	**4,82**

6.3.4 France

FRANCE	Input Area	
Peak load 2002 (GW); Load increase factor for 2020	72,9	1,3
Ratio Onshore : Offshore	100	0
Full load hours Onshore; Offshore	2000	0
Full load hours Weighted		2000
CCGT load factor (%); Annualised cost (€/kW/yr)	85	55

Installed Wind Capacity	PWind,inst / PL,max	Capacity Credit		
GW	%	Winter	Summer	Average
5	5,3	36,3	15,4	25,8
10	10,6	31,2	13,7	22,5
15	15,8	31,2	13,7	22,5
20	21,1	26,7	12,2	19,5
25	26,4	26,7	12,2	19,5
30	31,7	22,8	10,9	16,8
35	36,9	22,8	10,9	16,8
40	42,2	19,4	9,8	14,6
45	47,5	19,4	9,8	14,6

Average											
Wind capacity	**GW**	**5**	**5**	**10**	**15**	**20**	**25**	**30**	**35**	**40**	**45**
Full load hours	**h**	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000
Wind generation	**GWh**	**10000**	**10000**	**20000**	**30000**	**40000**	**50000**	**60000**	**70000**	**80000**	**90000**
CCGT load factor	%	85	85	85	85	85	85	85	85	85	85
CCGT full load hours	h	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Thermal capacity equivalent	GW	1,343	1,343	2,686	4,029	5,372	6,715	8,058	9,401	10,744	12,087
Capacity Credit Wind	%	0,0	25,8	22,5	22,5	19,5	19,5	16,8	16,8	14,6	14,6
Wind capacity contribution	GW	0,000	1,291	2,246	3,369	3,893	4,866	5,054	5,897	5,843	6,573
Required thermal capacity	GW	1,343	0,052	0,440	0,660	1,479	1,849	3,004	3,504	4,901	5,514
Specific cost of thermal equivalent	€/kW/yr	55	55	55	55	55	55	55	55	55	55
Capacity cost	Mio.€	73,87	2,85	24,22	36,33	81,35	101,68	165,19	192,73	269,58	303,28
Capacity cost per MWh Wind	**€/MWh**	**7,39**	**0,29**	**1,21**	**1,21**	**2,03**	**2,03**	**2,75**	**2,75**	**3,37**	**3,37**
Balancing cost per MWh Wind	**€/MWh**	**3,69**	**0,14**	**0,61**	**0,61**	**1,02**	**1,02**	**1,38**	**1,38**	**1,68**	**1,68**
Capacity & Balancing cost per MWh Wind	**€/MWh**	**11,08**	**0,43**	**1,82**	**1,82**	**3,05**	**3,05**	**4,13**	**4,13**	**5,05**	**5,05**

6.3.5 Greece

GREECE	Input Area	
Peak load 2002 (GW); Load increase factor for 2020	**7,5**	**1,3**
Ratio Onshore : Offshore	**80**	**20**
Full load hours Onshore; Offshore	**2000**	**3000**
Full load hours Weighted		**2200**
CCGT load factor (%); Annualised cost (€/kW/yr)	**85**	**55**

Installed Wind Capacity	PWind,inst / PL,max	Capacity Credit		
GW	%	Winter	Summer	Average
0,5	5,1	42,1	17,0	29,6
1	10,3	36,4	15,0	25,7
1,5	15,4	36,4	15,0	25,7
2	20,5	31,3	13,3	22,3
2,5	25,6	31,3	13,3	22,3
3	30,8	26,9	11,7	19,3
3,5	35,9	26,9	11,7	19,3
4	41,0	23,0	10,4	16,7
4,5	46,2	23,0	10,4	16,7

Average											
Wind capacity	**GW**	**0,5**	**0,5**	**1**	**1,5**	**2**	**2,5**	**3**	**3,5**	**4**	**4,5**
Full load hours	**h**	2200	2200	2200	2200	2200	2200	2200	2200	2200	2200
Wind generation	**GWh**	**1100**	**1100**	**2200**	**3300**	**4400**	**5500**	**6600**	**7700**	**8800**	**9900**
CCGT load factor	%	85	85	85	85	85	85	85	85	85	85
CCGT full load hours	h	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Thermal capacity equivalent	GW	0,148	0,148	0,295	0,443	0,591	0,739	0,886	1,034	1,182	1,330
Capacity Credit Wind	%	0,0	29,6	25,7	25,7	22,3	22,3	19,3	19,3	16,7	16,7
Wind capacity contribution	GW	0,000	0,148	0,257	0,386	0,446	0,557	0,579	0,675	0,668	0,752
Required thermal capacity	GW	0,148	0,000	0,038	0,057	0,145	0,181	0,308	0,359	0,514	0,578
Specific cost of thermal equivalent	€/kW/yr	55	55	55	55	55	55	55	55	55	55
Capacity cost	Mio.€	8,13	-0,01	2,11	3,16	7,98	9,98	16,93	19,75	28,26	31,79
Capacity cost per MWh Wind	**€/MWh**	**7,39**	**0,00**	**0,96**	**0,96**	**1,81**	**1,81**	**2,57**	**2,57**	**3,21**	**3,21**
Balancing cost per MWh Wind	**€/MWh**	**3,69**	**0,00**	**0,48**	**0,48**	**0,91**	**0,91**	**1,28**	**1,28**	**1,61**	**1,61**
Capacity & Balancing cost per MWh Wind	**€/MWh**	**11,08**	**0,00**	**1,44**	**1,44**	**2,72**	**2,72**	**3,85**	**3,85**	**4,82**	**4,82**

6.3.6 Ireland

IRELAND	Input Area	
Peak load 2002 (GW); Load increase factor for 2020	4,2	1,3
Ratio Onshore : Offshore	50	50
Full load hours Onshore; Offshore; Weighted	2000	3000
Full load hours Onshore; Offshore; Weighted		2500
CCGT load factor (%); Annualised cost (€/kW/yr)	85	55

Installed Wind Capacity GW	PWind,inst / PL,max %	Capacity Credit Winter	Capacity Credit Summer	Capacity Credit Average
0,25	4,6	50,8	19,5	35,2
0,5	9,2	50,8	19,5	35,2
0,75	13,7	44,2	17,1	30,6
1	18,3	44,2	17,1	30,6
1,25	22,9	38,2	14,9	26,5
1,5	27,5	38,2	14,9	26,5
1,75	32,1	32,9	12,9	22,9
2	36,6	32,9	12,9	22,9
2,25	41,2	28,4	11,3	19,8
2,5	45,8	28,4	11,3	19,8

Average												
Wind capacity	**GW**	**0,25**	**0,25**	**0,5**	**0,75**	**1**	**1,25**	**1,5**	**1,75**	**2**	**2,25**	**2,5**
Full load hours	**h**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**
Wind generation	**GWh**	**625**	**625**	**1250**	**1875**	**2500**	**3125**	**3750**	**4375**	**5000**	**5625**	**6250**
CCGT load factor	%	85	85	85	85	85	85	85	85	85	85	85
CCGT full load hours	h	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Thermal capacity equivalent	GW	0,084	0,084	0,168	0,252	0,336	0,420	0,504	0,588	0,672	0,755	0,839
Capacity Credit Wind	%	0,0	35,2	35,2	30,6	30,6	26,5	26,5	22,9	22,9	19,8	19,8
Wind capacity contribution	GW	0,000	0,088	0,176	0,230	0,306	0,332	0,398	0,401	0,459	0,446	0,496
Required thermal capacity	GW	0,084	-0,004	-0,008	0,022	0,030	0,088	0,106	0,186	0,213	0,309	0,343
Specific cost of thermal equivalent	€/kW/yr	55	55	55	55	55	55	55	55	55	55	55
Capacity cost	Mio.€	4,62	-0,22	-0,44	1,22	1,63	4,84	5,81	10,24	11,70	17,00	18,88
Capacity cost per MWh Wind	**€/MWh**	**7,39**	**0,00**	**0,00**	**0,65**	**0,65**	**1,55**	**1,55**	**2,34**	**2,34**	**3,02**	**3,02**
Balancing cost per MWh Wind	**€/MWh**	**3,69**	**0,00**	**0,00**	**0,33**	**0,33**	**0,78**	**0,78**	**1,17**	**1,17**	**1,51**	**1,51**
Capacity & Balancing cost per MWh Wind	**€/MWh**	**11,08**	**0,00**	**0,00**	**0,98**	**0,98**	**2,33**	**2,33**	**3,51**	**3,51**	**4,53**	**4,53**

6.3.7 Netherlands

NETHERLANDS	Input Area	
Peak load 2002 (GW); Load increase factor for 2020	14,9	1,3
Ratio Onshore : Offshore	50	50
Full load hours Onshore; Offshore	2000	3000
Full load hours Weighted		2500
CCGT load factor (%); Annualised cost (€/kW/yr)	85	55

Installed Wind Capacity GW	PWind,inst / PL,max %	Capacity Credit Winter	Capacity Credit Summer	Capacity Credit Average
0,75	3,9	50,8	19,5	35,2
1,5	7,7	50,8	19,5	35,2
2,25	11,6	44,2	17,1	30,6
3	15,5	44,2	17,1	30,6
3,75	19,4	44,2	17,1	30,6
4,5	23,2	38,2	14,9	26,5
5,25	27,1	38,2	14,9	26,5
6	31,0	32,9	12,9	22,9
6,75	34,8	32,9	12,9	22,9
7,5	38,7	32,9	12,9	22,9
8,25	42,6	28,4	11,3	19,8

Average													
Wind capacity	**GW**	**0,75**	**0,75**	**1,5**	**2,25**	**3**	**3,75**	**4,5**	**5,25**	**6**	**6,75**	**7,5**	**8,25**
Full load hours	**h**	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500
Wind generation	**GWh**	**1875**	**1875**	**3750**	**5625**	**7500**	**9375**	**11250**	**13125**	**15000**	**16875**	**18750**	**20625**
CCGT load factor	%	85	85	85	85	85	85	85	85	85	85	85	85
CCGT full load hours	h	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Thermal capacity equivalent	GW	0,252	0,252	0,504	0,755	1,007	1,259	1,511	1,763	2,015	2,266	2,518	2,770
Capacity Credit Wind	%	0,0	35,2	35,2	30,6	30,6	30,6	26,5	26,5	22,9	22,9	22,9	19,8
Wind capacity contribution	GW	0,000	0,264	0,528	0,689	0,918	1,148	1,194	1,393	1,376	1,548	1,720	1,637
Required thermal capacity	GW	0,252	-0,012	-0,024	0,067	0,089	0,111	0,317	0,370	0,638	0,718	0,798	1,133
Specific cost of thermal equivalent	€/kW/yr	55	55	55	55	55	55	55	55	55	55	55	55
Capacity cost	Mio.€	13,85	-0,66	-1,33	3,67	4,89	6,11	17,44	20,35	35,10	39,49	43,88	62,32
Capacity cost per MWh Wind	**€/MWh**	**7,39**	**0,00**	**0,00**	**0,65**	**0,65**	**0,65**	**1,55**	**1,55**	**2,34**	**2,34**	**2,34**	**3,02**
Balancing cost per MWh Wind	**€/MWh**	**3,69**	**0,00**	**0,00**	**0,33**	**0,33**	**0,33**	**0,78**	**0,78**	**1,17**	**1,17**	**1,17**	**1,51**
Capacity & Balancing cost per MWh Wind	**€/MWh**	**11,08**	**0,00**	**0,00**	**0,98**	**0,98**	**0,98**	**2,33**	**2,33**	**3,51**	**3,51**	**3,51**	**4,53**

6.3.8 UK

UNITED KINGDOM	Input Area	
Peak load 2002 (GW); Load increase factor for 2020	53,0	1,3
Ratio Onshore : Offshore	40	60
Full load hours Onshore; Offshore	2000	3000
Full load hours Weighted		2600
CCGT load factor (%); Annualised cost (€/kW/yr)	85	55

Installed Wind Capacity	PWind,inst / PL,max	Capacity Credit		
GW	%	Winter	Summer	Average
3	4,4	53,7	20,4	37,1
6	8,7	53,7	20,4	37,1
9	13,1	46,8	17,7	32,2
12	17,4	46,8	17,7	32,2
15	21,8	40,5	15,4	27,9
18	26,1	40,5	15,4	27,9
21	30,5	35,0	13,3	24,2
24	34,8	35,0	13,3	24,2
27	39,2	35,0	13,3	24,2
30	43,5	30,2	11,6	20,9
33	47,9	30,2	11,6	20,9

Average													
Wind capacity	**GW**	**3**	**3**	**6**	**9**	**12**	**15**	**18**	**21**	**24**	**27**	**30**	**33**
Full load hours	**h**	2600	2600	2600	2600	2600	2600	2600	2600	2600	2600	2600	2600
Wind generation	**GWh**	**7800**	**7800**	**15600**	**23400**	**31200**	**39000**	**46800**	**54600**	**62400**	**70200**	**78000**	**85800**
CCGT load factor	%	85	85	85	85	85	85	85	85	85	85	85	85
CCGT full load hours	h	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Thermal capacity equivalent	GW	1,048	1,048	2,095	3,143	4,190	5,238	6,285	7,333	8,380	9,428	10,475	11,523
Capacity Credit Wind	%	0,0	37,1	37,1	32,2	32,2	27,9	27,9	24,2	24,2	24,2	20,9	20,9
Wind capacity contribution	GW	0,000	1,112	2,224	2,902	3,869	4,191	5,029	5,073	5,798	6,522	6,266	6,893
Required thermal capacity	GW	1,048	-0,064	-0,128	0,241	0,321	1,047	1,256	2,260	2,583	2,906	4,209	4,630
Specific cost of thermal equivalent	€/kW/yr	55	55	55	55	55	55	55	55	55	55	55	55
Capacity cost	Mio.€	57,61	-3,53	-7,06	13,25	17,66	57,56	69,07	124,30	142,05	159,81	231,50	254,65
Capacity cost per MWh Wind	**€/MWh**	**7,39**	**0,00**	**0,00**	**0,57**	**0,57**	**1,48**	**1,48**	**2,28**	**2,28**	**2,28**	**2,97**	**2,97**
Balancing cost per MWh Wind	**€/MWh**	**3,69**	**0,00**	**0,00**	**0,28**	**0,28**	**0,74**	**0,74**	**1,14**	**1,14**	**1,14**	**1,48**	**1,48**
Capacity & Balancing cost per MWh Wind	**€/MWh**	**11,08**	**0,00**	**0,00**	**0,85**	**0,85**	**2,21**	**2,21**	**3,41**	**3,41**	**3,41**	**4,45**	**4,45**

7 CONCLUSIONS

This report considers the intermittent nature of RES-E generation, for which wind power generation is the dominant example. A "top-down" method[16] is demonstrated for the capacity implications of integrating intermittent RES-E generation into a grid. This estimates the magnitude and cost of both the additional system balancing and system capacity requirements. For wind power, such additional *controllable capacity* depends significantly on the proportional capacity of wind penetration, for which the quantification of the capacity credit is important.

Moreover, also the grid infrastructure related measures and cost – for grid connection and grid reinforcement/extension caused by large-scale RES-E grid integration – are subject to comprehensive evaluation in this report.

The major results of the estimation of the additional requirements and cost due to increasing the proportional capacity of intermittent RES-E generation (wind in particular) in a system are:

- Less experience and empirical data are available on grid related aspects in the context of large-scale RES-E grid integration, not least due to the fact that the definition of the interfaces between the RES-E power plant itself (incl. the "internal grid" and the corresponding electrical equipment) and the "external" grid infrastructure (i.e. new grid connection and reinforcement/extension of the existing grid) isn't clear yet. In this context a fundamental unbundling discussion is recommended.

- System balancing requirements and cost are increased by random fluctuations and by forecast errors of both intermittent RES-E generation and load (since these are generally not correlated). In practice, the additional cost for increased controllable capacity allocated to wind generation are in the range of 0-3 €/MWh (depending on wind power penetration). This cost should be allocated to the corresponding balancing markets. In practice, the balancing market prices should send out the correct price signals to the market competitors so the network remains stable.

- The allocation of system capacity cost (for system security) to a single generation technology (e.g. wind) is deceptive, since this ignores the requirements of the other generation. In practice, spare controllable capacity is already established for the secure operation of conventional generation plant meeting varying demand. Therefore, the system capacity requirements due to intermittent RES-E (wind) generation cannot be considered on a "MW to MW" basis, neither now or in the future. In practice, additional system capacity caused by increasing intermittent RES-E (wind) generation does not necessarily come from these new power plants entering the market. For instance, existing conventional and controllable thermal generation units, including peaking generation, and/or existing pumped hydro storage power plants are sufficient for the new

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[16] I.e., no particular country-specific power system is analysed in detail by applying typical engineering tools (taking into account system specific features in the context of large scale wind generation).

intermittent generation also. Therefore, in practice, the socialisation of the cost associated with additional system capacity requirements due to increasing intermittent RES-E generation will be established by the balancing and wholesale electricity markets; these give satisfactory prices signals for the provision of adequate generation capacities.

In view of the conclusions above, many European electricity markets still have structural deficiencies and inefficiencies in their balancing and settlement procedures that discriminate against intermittent RES-E generation. Therefore, a re-design of corresponding market structures and procedures is seen as a precondition for integrating significant total capacity of intermittent RES-E into the national and international networks. This especially applies to wind power now, for which there are very large capacity expectations.

Addressing technological development in the short- to medium-term, the implementation of improved forecasting tools will mitigate the intrinsic intermittency of wind generation and, subsequently, reduce corresponding costs for balancing the system. The future role of *new*, advanced storage technologies, such as battery and fuel cell systems, in providing corresponding balancing services is not yet clear. Therefore their market entry cannot yet be predicted or quantified.

In conclusion, it is noted that long-term and fundamental market re-design should focus on having manageable loads on the demand-side. Such loads should change sympathetically with changes in generation, especially of intermittent generation. Such management will reduce both system balancing and system capacity requirements substantially and hence their costs. The preconditions for the significant implementation of demand response applications are (i) the implementation of known and future technologies for communication between generation and demand, (ii) tariffs that encourage rapid and sufficient demand-side load changes in response to the needs of supply, i.e. have minimal transaction cost for consumers.

Nevertheless, the active integration of the demand-side response in overall system operation is indispensable. This will subsequently minimise the additional requirements on the system related to future substantial intermittent RES-E generation.

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