Economics of large-scale intermittent RES-E integration into the European grids: analyses based on the simulation software Green*Net*

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Abstract: Market integration of Renewable Energy Technologies for Electricity (RES-E) generation is one of the core topics in the energy policy agenda of the European Commission (EC). However, legislation in this context still faces a variety of lacks (e.g. ignoring unbundling principles) in almost all countries of the European Union (EU). The recently finished EC-Project Green*Net* addresses these existing inadequacies and models dynamic time paths up to the year 2020 for a variety of least-cost RES-E grid integration cases in the EU for different degrees of unbundling and different cost allocation schemes. The major results derived from Green*Net* clearly demonstrate that the degree of unbundling and the implemented allocation principles of different disaggregated cost elements significantly influence RES-E deployment both on national as well as on EU level up to the year 2020. The major conclusion is that serious unbundling and correct allocation of RES-E related grid integration costs only guarantee the fulfilment of the ambitious EC goals with minimal costs for society.

Keywords: RES-E generation; RES-E policies; modelling; unbundling; system operation; grid infrastructure; cost allocation; socialisation of cost; grid tariffs.

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1 Introduction

The EC-Directive on the liberalisation of electricity markets (EC, 2004) requires the electricity supply industry to be competitive, yet realises that many aspects of the electricity supply are natural monopolies. Consequently, it is considered best for different segments of the electricity system to be separated into clearly defined and separately accounted entities, as there are electricity generation, high-voltage transmission, low-voltage distribution and customer supply. This is called as unbundling, which is one of the cornerstones of the liberalised electricity market. Separation of the competitive segments of electricity generation and customer supply from the grid infrastructure is seen as a precondition for non-discriminatory grid access for third parties (e.g. RES-E generators) as well as for transparent grid regulation procedures and grid tariff determination.

For RES-E generators, particular difficulties arise when connecting dispersed generation to the existing grids. Who should pay for the connection and extra transmission and distribution lines that may be necessary? In practice, for relatively large-scale RES-E grid integration (e.g. wind), the corresponding measures and costs are frequently charged directly to the RES-E power plant. Thus, the new RES-E generator has to pay for the extra capital costs of grid infrastructure elements; yet the grid is supposed to be unbundled. This is a relatively a new phenomenon, because in the past, for example, for centralised power plants, the costs of the grid infrastructure were not allocated to the long-run marginal generation costs (see e.g. Soeder, 2004).

The intermittent nature of some RES-E generation technologies such as wind, furthermore, expects additional measures for overall system operation. Moreover, in general, the consideration of different time scales is important for managing generation and load and with large amounts of intermittent RES-E generation in the system in particular. These time scales vary from seconds to minutes, minutes to days and longer (see e.g. Ackermann, 2005):

- In the short-term (time scales below seconds to several hours), a variety of balancing (ancillary) services are necessary for maintaining a stable system operation. The driver for a short-term system balancing requirements is the magnitude of random power fluctuations, caused by unpredictable changes in both load and generation. Currently, in different European countries, a variety of different schemes exist for the allocation of corresponding balancing costs.
- In the long-term, in competitive electricity markets, the market itself will be responsible for providing enough generation capacities that would be able to meet peak demand in the system. This is also true for the 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 to maintain adequate security of supply standards in the system. In particular, the capacity contribution of generation technologies such as wind has to be estimated based on robust approaches (capacity credit). Moreover, the corresponding additional costs for the overall system have to be determined and allocated correctly.

The discussion above indicates that a variety of different unbundling aspects are still unsolved in the context of large-scale intermittent RES-E grid integration. Therefore, the analysis of unbundled RES-E grid integration costs in subsequent sections requires the consideration of the following separated segments of the electricity supply chain:

- grid infrastructure (grid connection, grid extension/reinforcement)
- electricity generation based on (intermittent) RES-E technologies
- system operation services (including storage options and flexible loads).

The literature on critical reviews of unbundling in the context of RES-E grid integration is scarce. Strategic approaches on grid infrastructure planning (and operation) meeting the future requirements of large-scale RES-E grid integration are presented, for example, by Soeder (2004), Auer et al. (2005) or Dowling and Hurley (2005). On country-specific level corresponding publications exist, for example, for The Netherlands (Hooft, 2003; Groenhuijse, 2005), Denmark (Bach, 2004), Spain (Tembleque, 2004), Ireland (Smith, 2004) or the UK (ILEX, 2002, Ford, 2005). Remaining literature mainly addresses selected aspects of RES-E grid integration (e.g. in the recently published German DEWI (2005) study separation of grid connection of offshore wind is not addressed explicitly).

The major objective of this paper is to model different least-cost RES-E grid integration scenarios (wind onshore and offshore in particular) in the EU15 countries and selected new Member States for different unbundled cases based on the simulation software Green*Net*. The database of this software tool contains a comprehensive and consistent empirical data on several disaggregated cost elements of RES-E technology grid integration on EU country level.

This paper is organised as follows. Section 2 provides background information and a brief discussion on the major unbundled segments in the electricity supply chain. Section 3 presents and discusses the major results derived from the simulation software Green*Net.* In Section 4, different cost allocation scenarios for the grid connection are analysed based on a particular offshore wind project. And finally, Section 5 derives the conclusions on the correct cost allocation of different disaggregated cost elements in the context of large-scale intermittent RES-E grid integration.

2 Unbundled segments in the electricity supply chain

2.1 Grid infrastructure (grid connection and grid extension/reinforcement)

Grid connection often is a significant economic barrier for RES-E generation technologies in dispersed locations. If the new RES-E developer has to pay all the costs of grid connection upfront, then a compromise between the best generation sites and acceptable grid conditions has to be made, as is often the case for wind and small hydropower (see e.g. Resch et al., 2003).[1] To pay for the connection, the RES-E developer includes the costs into the long-run marginal generation costs. However, if the grid connection costs are covered by the grid operator (i.e. the costs are ‘socialised’ via grid tariffs of ‘per unit’ charges), then the initial burden does not fall on the first RES-E developer. Obviously, RES-E developers should not have a ‘right’ to be connected anywhere irrespective of connection costs, so the regulatory authority has to give guidance and adjudicate about disagreements (see, e.g. Hooft, 2003).

The need for extensions and reinforcements of the existing grid infrastructure has a variety of reasons. Changes in generation and load at one point in the network, in principle cause changes throughout the system, which may cause power congestion (bottlenecks). Usually, it is not possible to identify one (new) point of generation as the single cause of such difficulties. Therefore, the allocation of changes of load flows in a system to a single new generator connected to the system (e.g. a new wind farm) is ambiguous, as established conventional generators or changes in demand may cause an equal burden on the grid infrastructure (see, e.g. ILEX, 2002). Therefore, one of the major unbundling issues is to discuss different cost allocation strategies for intermittent RES-E grid integration. According to the textbooks in economic theory, it is expected to allocate both the grid connection costs and the grid extension/reinforcement costs to the grid infrastructure and to spread (socialise) these costs through the transmission and distribution tariffs.[2] In practice, however, grid connection costs are still allocated to the RES-E power plant in almost all European countries (except e.g. in Denmark). According to ongoing discussions on this issue in a few countries (e.g. UK, The Netherlands and Germany) this pattern may change in the future. Nevertheless, in the existing version of the Green*Net* model, the grid connection costs are not unbundled in the default settings.

2.2 Electricity generation based on (intermittent) RES-E technologies

Currently, large electricity systems mainly operate without advanced energy storage technologies (except those systems with large amounts of pumped hydro-storage plants). Therefore, at any instant, the output from all the electricity generators has to be controlled to equal the total consumer demand. In addition, the electricity system must be reliable and robust, able to continue operation in the event of concurrent failures. For these reasons, system operators have to forecast load and generation on timescales from seconds to years and have methods to control the balance continuously.

In this context, when having large amounts of RES-E technologies in a system, two characteristics of intermittent electricity generation (in particular wind) have to be addressed briefly: *variability* and *predictability*.

Variability of wind generation is often spoken as a major problem (see, e.g. Gül and Stenzel, 2005). However, the variability has distinctive characteristics, for example:

- For *individual wind turbines*, the variations of the power output on second scale can be quite large, depending on the type of wind turbine control and conversion system. Furthermore, there can be substantial short-term variations during transients (e.g. start-up at high wind speed and shutdown).
- For an *individual wind farm*, the variation in the total output power is small for timescales of tens of seconds, due to the averaging of the output of individual turbines across the wind farm.
- For a *number of wind farms* spread across a large area, such as a national electricity system, the variation in the total output power of all the wind farms is small for timescales of minutes or less, perhaps tens of minutes. This is termed as 'geographic diversity'.

Grid operators only need to deal with the net output of groups of wind farms, thus, the important question is what variability needs to be planned for on timescales of minutes or tens of minutes and upward?

Methods and models for the power output forecasting from the wind farms have been substantially improved in recent years. Forecasting the wind power aims to increase the predictability of the wind resource and so ease the balance of generation and load. In general, the wind forecasting has a greater value where the financial balancing markets are part of a competitive trading system for the electricity than if forecasting is purely a tool for the system operators with their technical balancing. This is because the balancing market provides a financial incentive to both retailers and generators to fulfil their output projections accurately. The more precise they are, the less the financial penalties and the greater the system technical efficiency (see e.g. van Werven et al., 2005).

2.3 System operation requirements due to large-scale RES-E integration

Owing to large-scale intermittent RES-E generation, the system operator has to take care of additional arrangements for both the short-term balancing of generation and load as well as long-term generation capacity provision maintaining system security (see e.g. Milborrow, 2004; Hirst and Hild, 2004; Swider and Weber, 2005b). Previous paragraphs already indicate that there are still many open questions, for example,

- where to allocate the corresponding costs
- whether or not the corresponding markets (balancing/wholesale markets) send out the right price signals or
- which mechanisms and procedures prevent competition in system operation?

In the short-term system, frequency is the parameter used to indicate the balance between the generation and the load. The system frequency must be maintained continuously within narrow statutory limits around 50 Hz. With no change in generation, the system frequency decreases when the load is greater than the generation and increases when the generation is greater than the load. To manage the frequency effectively, the system operators utilise a range of balancing (ancillary) services that operate according to different time horizons and predominantly involve changes in the generation rather than in the load (see e.g. van Werven et al., 2005).

Long-term analyses estimate the capacity contribution of intermittent RES-E generation (in particular wind) on system level. Although the wind power throughout a national network makes some contribution to assured capacity, this contribution is significantly less than for an equivalent conventional generation or non-intermittent RES-E generation. The relevant parameter in estimating the system capacity requirement caused by intermittent RES-E generation is the capacity credit (see e.g. Giebel, 2001). This capacity credit is equal to the average capacity factor at low wind penetrations, but decreases with increasing wind penetration in a system.[3] Therefore, in the Green*Net* modelling approach, the amount of conventional capacity has to be determined that can be *displaced* by the intermittent RES-E generation, while maintaining the same degree of system security.

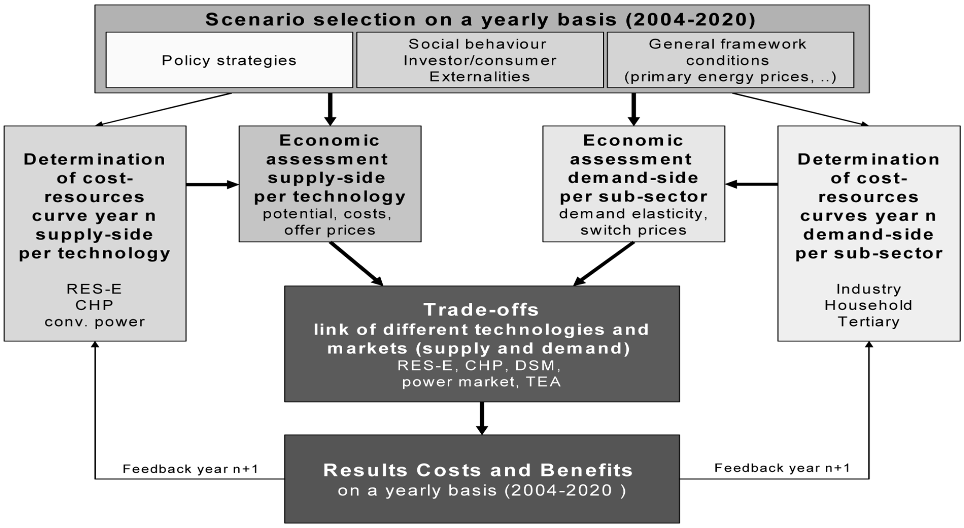
3 Results derived from the least-cost simulation software Green*Net*

The evaluation of strategies for an enhanced least-cost grid integration of RES-E generation technologies (with and without consideration of additional costs for grid extension/reinforcement and/or system operation) for different unbundled cases is conducted based on the simulation model Green*Net*. Section 3.1 briefly describes this software tool.

3.1 The GreenNet computer model

The Green*Net* model enables a comparative and quantitative analysis of least-cost RES-E grid integration strategies in the liberalised European electricity market (i.e. several ‘old’ EU15 countries and the new Member States Czech Republic, Hungary, Poland and Slovakia). The analysis can be conducted on aggregated (EU Member States’) level or for the individual Member States on an annual basis for the period 2005 to 2020 (2004 is the initial year). The major purpose of this software tool is to investigate the costs of RES-E deployment under different constraints and different strategies on allocating the corresponding grid related and system related costs, see Figure 1.

Figure 1 Overview of the least-cost modelling approach in the Green*Net*



The general modelling approach in Green*Net* is to describe both the electricity generation technologies (supply curve) and the energy efficiency options (demand curve) by deriving corresponding *dynamic cost–resource curves*. The costs as well as the potentials of these dynamic cost–resource curves can change year by year. These changes are given endogenously in the model depending on the outcome of the previous year (n–1) and the policy framework conditions set for the simulation year (n).

On the basis of the derivation of the dynamic cost–resource curves, an *economic assessment* takes place considering scenario specific settings like RES-E policy selection, socio-economic parameters (consumer and investor behaviour) as well as wholesale electricity price and demand forecasts. Wholesale electricity price projections on the conventional power market are implemented exogenously in Green*Net*. Different wholesale price scenarios (e.g. for different fuel prices, CO_2 certificate prices, etc.) are calculated based on the optimisation tool E2M2^s. A comprehensive model description of E2M2^s can be found in Swider and Weber (2005a).[4]

Then in the *economic assessment*, additional costs for system operation (with versus without storage options) and grid reinforcement/extension are modelled and – in the case of selection – allocated to the marginal generation costs of the corresponding RES-E technology. The overall economic assessment includes a transition from generation and saving *costs* to *bids*, *offers* and switch *prices*.

Promotion instruments for RES-E technologies include the most important price-driven strategies (feed-in tariffs, tax incentives, investment subsidies, subsidies on fuel input) and demand-driven strategies (quota obligations based on tradable green certificates (including international trade), tendering schemes). In addition, electricity taxes and other direct promotion instruments supporting energy efficiency measures on the demand side that can also be chosen and investigated (see e.g. Huber et al., 2004a). As Green*Net* is a dynamic simulation tool, the user can change RES-E policies and parameter settings within a simulation run on a yearly basis. Furthermore, several instruments can be set for each country individually.

The results are derived on a yearly basis by determining the equilibrium level of supply and demand within each market segment considered. For a detailed description of the Green*Net* modelling approach, it is referred to Huber et al. (2004c). Moreover, a detailed description of the deviation of dynamic cost-resource curves as well as the comprehensive Green*Net* database is conducted by Resch et al. (2003).

3.2 Scenarios selection in GreenNet

Several simulation runs in the Green*Net* are based on the assumption that currently implemented RES-E policy instruments remain without any adaptation up to 2020 (*Business as Usual (BAU)* RES-E policy). Sensitivity analyses consider the spread of options to allocate grid- and system-related costs. This means that either the RES-E developer or society as a whole pay the additional costs of RES-E grid integration. Wind power, onshore and offshore, is considered especially because of its dominant position for the new RES-E technologies, now and in the future. Wind power also relates to:

- grid connection with both the transmission and distribution; the latter including weak grid conditions (i.e. causing additional grid extension/reinforcement costs) and
- the possibility of requiring additional system capacity for periods of weak wind.

The scenario whereby 'society as a whole' pays costs that requires further explanation for the liberalised electricity market, as the concepts are derived from the previously vertically integrated power systems. Previous to liberalisation, society can be said to have owned the grid infrastructure, as it was initially funded by governments through taxation. In the liberalised electricity market now it is unclear, however, where to allocate the costs of new equipment for grid connection and/or grid extension/reinforcement. Either these costs have to be paid for by the owner of the new RES-E power plant, which may be a company with investors or by the grid company, which is always a licensed monopoly. In the former case, expenditures initially come from investors and then have to be recovered from the future generation income. In the latter case, expenditures come from internal reserves of the established grid company and are later recovered from the 'use of system' per unit tariff levied on the eventual electricity suppliers, who pass on the expenses to their consumers, that is, to 'society'.

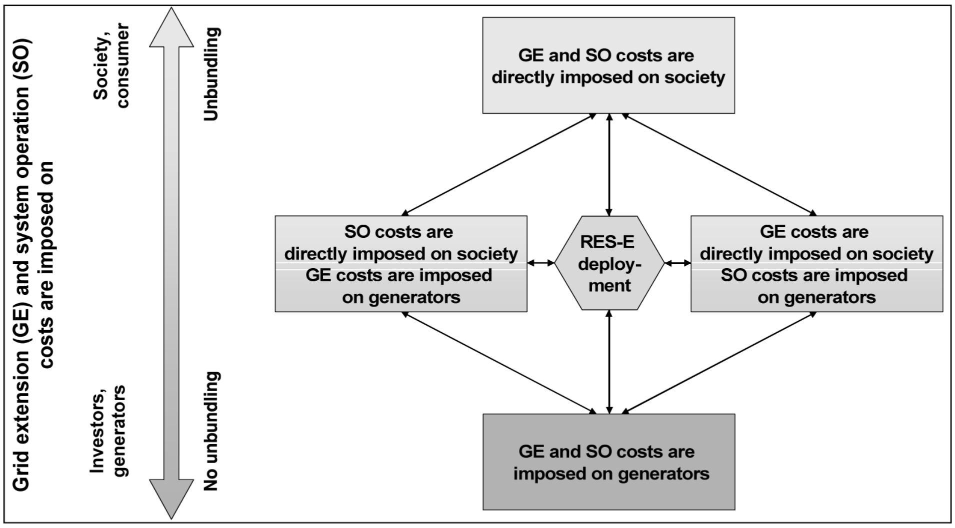
In detail, the following cost allocation scenarios can be selected in the Green*Net* model:

- *Full unbundling between electricity generation and the grid/system*: society pays for both grid extension/reinforcement and system operation costs caused by the RES-E technologies. The RES-E developer can neglect several additional grid- and system-related costs in its investment decision. This scenario is used as reference case as this approach is implemented in many EU Member States (grid connection costs, however, are not unbundled in the reference case; see Section 2.1).

- *Grid extension/reinforcement costs only are allocated to RES-E plant developer*: in this case, it is assumed that the system operation costs are still fully covered by the society, but the grid extension/reinforcement costs are imposed on the RES-E developer. Different sensitivity analyses on the effects of grid extension/reinforcement costs (low, medium and high per unit costs) can be conducted both for the new and existing RES-E plants as well as only for the new RES-E plants.
- *System operation costs only are allocated to RES-E developer*: starting from the fully unbundled case, now the opposite sensitivity analyses are conducted. In detail, the consideration of additional system operation costs – being imposed on the intermittent RES-E generators – on overall RES-E deployment can be studied. Important parameter variations refer to the settings of:
  - the capacity credit of wind and
  - the range of the corresponding system operation costs (assuming low, medium and high cost scenarios).
- *Both grid extension/reinforcement and system operation costs are allocated to RES-E developer*: again, sensitivity analyses are carried out to investigate the cumulative effects of the grid extension/reinforcement and the system operation on RES-E deployment over time.

Figure 2 shows an overview of different cost allocation scenarios being implemented in the Green*Net* model. Further assumptions are described in the Appendix.

Figure 2 Overview of different cost allocation scenarios in the Green*Net* model



3.3 Full unbundling (reference case): extra grid and system costs are allocated to 'society'

Figure 3a indicates RES-E deployment in the reference scenario up to the year 2020. Already existing RES-E generation in Europe is dominated by large-scale hydropower, followed by wind onshore and biomass. However, the amount of the large-scale hydropower will not increase significantly in the future due to adverse environmental impact (addressed e.g. in the Water Framework Directive (EC, 2000))[5] as well as limited additional potential. The most significant increase can be expected for the wind energy: for onshore plants in the entire period of 2005–2020 and for offshore plants especially beyond 2013. Moreover, it can be expected that around 45% of RES-E generation from new RES-E plants comes from the wind onshore and 28% from the wind offshore. This leads to a share of 29% wind onshore and 14% wind offshore on total RES-E generation in 2020.

Furthermore in Table 1, the share of the total RES-E generation compared to the total electricity generation on EU15 (EU15+4) country level for the years 2010 and 2020 is given. From the RES-E policies' point-of-view, the year 2010 is important as each EU Member State has to fulfil indicative targets with respect to RES-E generation according to the EC-Directive 2001/77/EC (see e.g. EC, 2001). The results in Table 1 on aggregated EU15 (EU15+4) country level show that the indicative targets are not entirely met.[6]

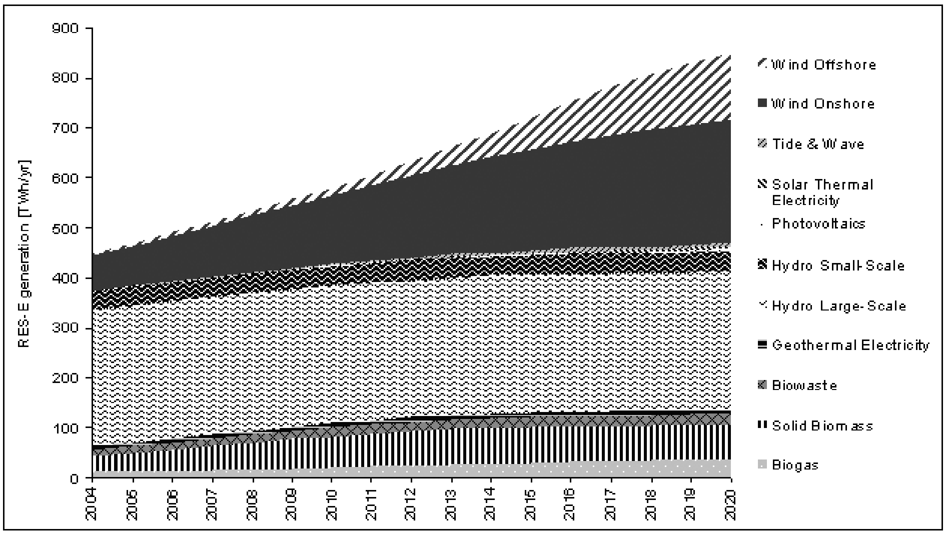
Table 1 Comparison of RES-E deployment based on Green*Net* and indicative targets due to the EC-Directive 2001/77/EC

Comparison	*RES-E deployment based on GreenNet*		*Indicative targets due to EC-Directive*	
	EU15	*EU15+4*	*EU15*	*EU15+4*
2010	18.5%	17.5%	22.1%	20.7%
2020	24.7%	23.0%		

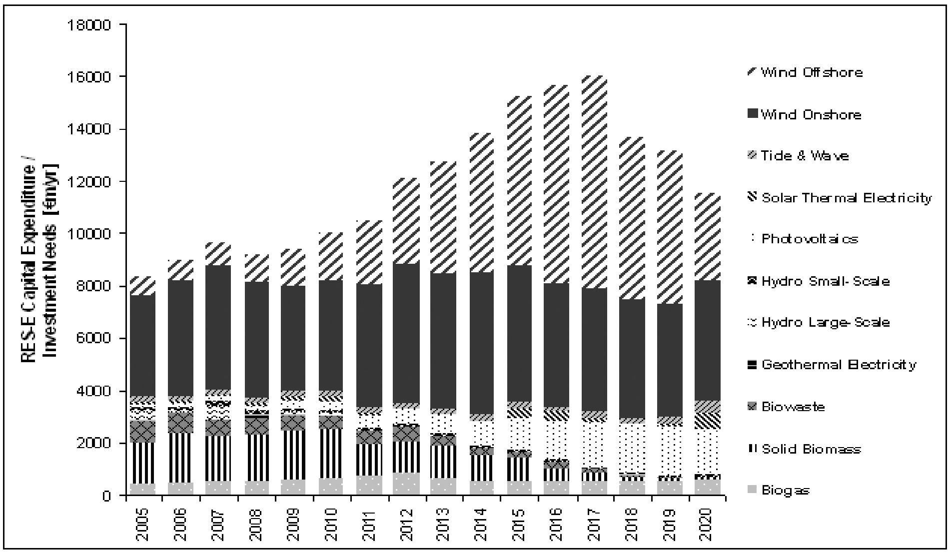
Derived from Figure 3a the corresponding annual RES-E capital expenditures over time – assuming BAU RES-E policies up to 2020 – are indicated in Figure 3b. Significant investments are necessary to realise these new RES-E capacities in the reference scenario. Around €9000 million per year are estimated up to the year 2010, around €14,000 million per year in the decade thereafter. On RES-E technology level, the capital expenditures significantly vary over time. While annual investments in wind onshore and biogas are constant in the investigated period, investments in solid biomass and (bio)waste plants are mainly expected from the year 2005 to 2015. Beyond 2015, only limited biomass and (bio)waste potentials are implemented, as their competitiveness compared to remaining RES-E technologies is worse. Finally, high investments in wind offshore are expected beyond 2010.

According to wind deployment (both onshore and offshore) presented in Figure 3a, the corresponding annual grid extension/reinforcement costs are depicted in Figure 4 up to the year 2020. Assuming average specific grid extension/reinforcement costs of the existing grids based on a literature survey (details of model implementation are shown in the Appendix), it can be expected that in 2020 annual grid infrastructure costs of around €450 million are required to integrate the new wind onshore and offshore capacities.[7] Considering already implemented wind specific grid extension/reinforcement measures, annual costs rise from about €50 million to €500 million, see Figure 4.

Figure 3 (a) RES-E deployment of new RES-E technologies in the period 2005–2020 within the EU15+4(PL, CZ, SK, HU) in the BAU scenario and (b) annual RES-E capital expenditures in the period 2005–2020 within the EU15+4(PL, CZ, SK, HU) in the BAU scenario



(a)



(b)

The additional system operation costs caused by system balancing and provision of system capacity margins due to the intermittent wind generation are depicted in Figure 5. Again, two cases are considered:

- wind energy can contribute to system capacity (i.e. a capacity credit is taken into account) and
- wind energy cannot contribute to system capacity.

It is important to note, however, that the wind in fact has a capacity credit (see e.g. Giebel, 2001) and the example is merely to illustrate the overall bandwidth in the cost calculations. The sensitivity analyses estimate the system operation costs in the different scenarios.

Figure 4 Development of annual additional grid extension/reinforcement costs due to RES-E deployment upto the year 2020 in the BAU scenario

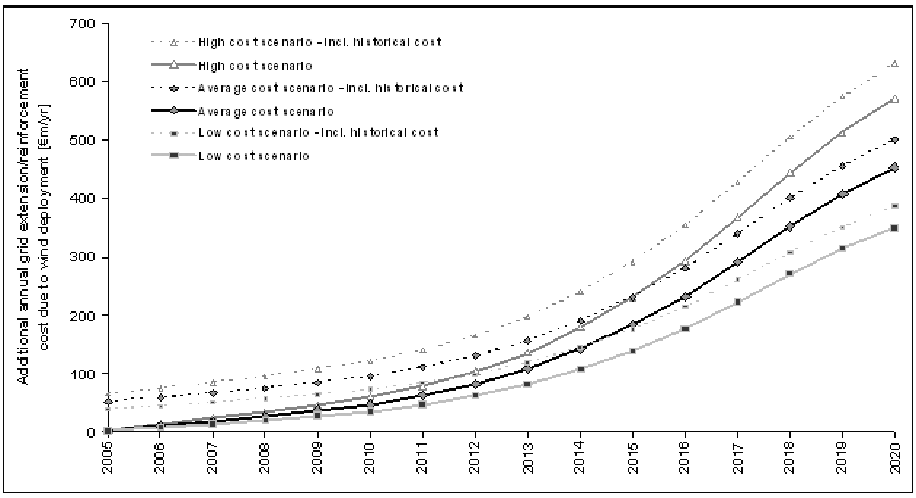
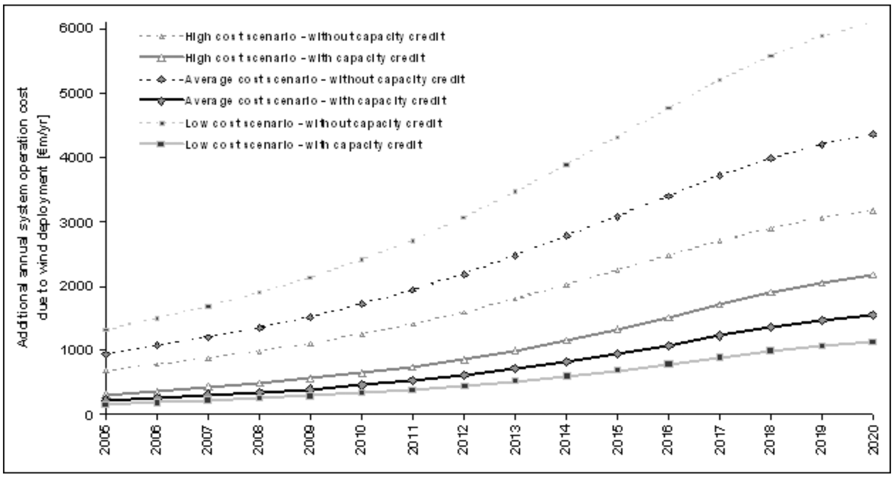


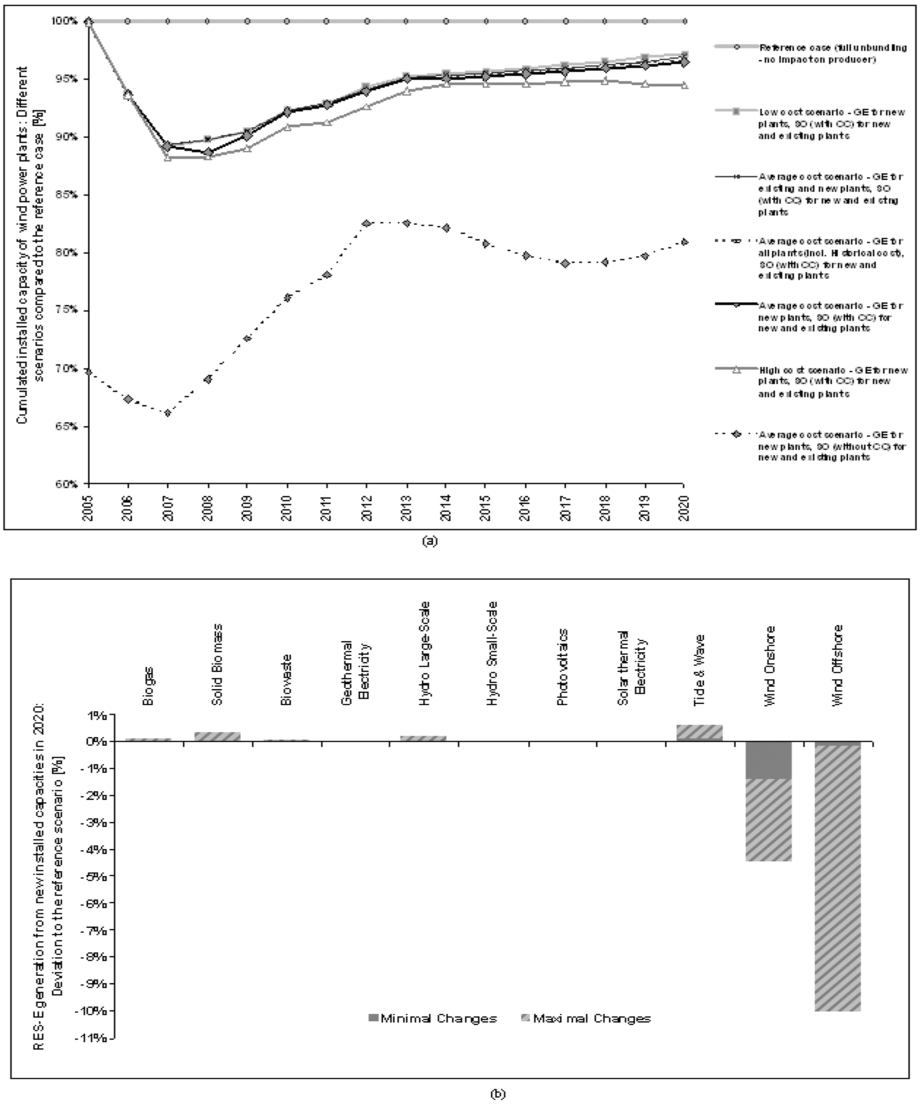
Figure 5 Development of annual additional system operation costs due to RES-E deployment up to 2020 in the BAU scenario



3.4 No unbundling: extra grid and system costs are allocated to RES-E developer

The results on allocating both the grid extension/reinforcement costs and the system operation costs to the RES-E developer are summarised in Figure 6a. The changes in the total RES-E portfolio in the 'EU15+4' countries caused by these extra costs compared to the reference case are depicted in Figure 6b. It can be seen that the share of both the wind onshore and offshore will be reduced. Again, the deviation depends on the assumed framework conditions. If no capacity credit is awarded to the wind power, significantly less wind deployment occurs. The reduction is partly compensated by larger deployment of remaining RES-E technologies as their competitiveness increases in relation to the wind power. Moreover, an increased growth can be expected for biogas, biomass, hydropower as well as tide and wave energy.

Figure 6 (a) No unbundling: impact of grid extension/reinforcement costs and system operation costs on cumulated installed wind capacity compared to the reference case (full unbundling) on the EU15+4 country level. Legend: GE = Grid Extension/reinforcement, SO = System Operation, CC = Capacity Credit and (b) no unbundling: deviation of RES-E generation from new installed RES-E capacities compared to the reference case (full unbundling) on EU15+4 country level

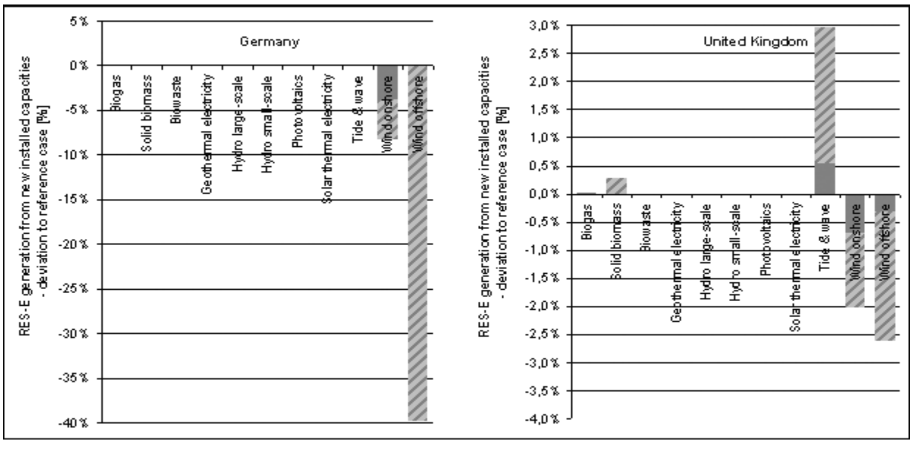


The impact of additional grid extension/reinforcement costs and system operation costs significantly varies between the EU Member States. The effects mainly depend on the particular RES-E policy scheme. Figure 7 compares the two extreme cases of Germany (feed-in tariff scheme) and the UK (obligated quota system):

- The influence on total new RES-E generation is significant for price-driven instruments (i.e. feed-in tariff, investment incentive and tax relief), as no compensation mechanism is available to reduce the negative impact of the additional costs allocated to the RES-E developer. Moreover, if grid related and system related costs are not unbundled and, simultaneously, wind deployment shall remain, then an adaptation of the price-driven instruments is necessary (i.e. an increased feed-in tariff).
- On contrary, for capacity-driven instruments (i.e. quota systems with and without tradable green certificates, tender procedure), the additional costs are partly compensated by an increase in the green certificate price and the (marginal) bid price. The reason is that a certain quantity of new RES-E capacity has to be reached. The consideration of grid- and system-related costs reduces the competitiveness of the wind energy compared to remaining non-intermittent RES-E technologies. Therefore, the deployment portfolio of different RES-E technologies changes only, but not the total new RES-E capacity.

The major conclusion based on the results shown in Figure 7 is that the degree of unbundling and the allocation principles of different disaggregated cost elements significantly influences RES-E deployment in Europe up to the year 2020 in general (and the wind in particular).

Figure 7 No unbundling: deviation of RES-E generation from newly installed RES-E capacities from the BAU reference case (full unbundling) in Germany (feed-in tariff scheme (left)) and the UK (obligated quota system (right))



The effects of imposing either grid extension/reinforcement costs or system operation costs on the RES-E developer are not separately presented. Imposing grid extension/reinforcement costs to the RES-E developer results in RES-E deployments similar to the fully unbundled case (see Section 3.3) and vice versa for system operation costs according to RES-E deployment in Section 3.4.

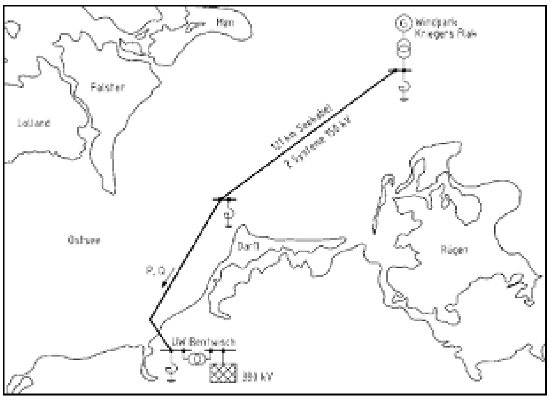
Continuing the discussion on different cost allocation policies for RES-E grid integration, finally in Section 4 the effects of separate treatment/depreciation of grid connection costs are discussed for a specific offshore wind project in Germany.

4 Different depreciation scenarios of offshore grid connection costs: a case study of Kriegers Flak (Germany)

According to current legislation in Germany (Renewable Energy Sources Act (EEG-Gesetz, 2004)), several grid connection costs of wind farms are allocated to the RES-E developer, whereas grid extension/reinforcement costs (caused by RES-E integration) of the existing grid are allocated to the grid operator. In practice, this means that parts of the feed-in tariff are used to finance the grid connection infrastructure. The unbundling principles expect separation of grid infrastructures from competitive businesses (generation, customer supply) and to control them in the grid regulation process.

Implementing the unbundling principles in a consistent manner, therefore, means that several grid-related costs, both grid connection and grid extension/reinforcement, shall be allocated to the grid operator and socialised via grid tariffs. In the following, the consequences of a consistent cost allocation are discussed by analysing a planned offshore wind project in the Eastern Sea of Germany: *Kriegers Flak*. The location is in the Northeast of *Wittow* peninsula as shown in Figure 8. The planned total capacity is 350 MW (75 wind turbines having a rated power between 3 and 5 MW each). Expected investment costs are around €750 million. Annual generation is assumed to be around 1400 GWh. The nearest fitting point for grid connection is *Bentwich*, being 121 km far from the offshore site. Grid connection is realised with two 150 kV undersea cables, see Table 2.

Figure 8 Offshore wind project *Kriegers Flak*



Source: www.ofw-online.de.

The following grid connection costs for the *Kriegers Flak* wind farm are assumed: specific cable costs: €350 per metre and laying costs: €150 per metre. The installation costs of the offshore platform are €25 million. The resulting total costs for the grid connection are calculated with €146 million. This is around 20% of the total investment costs of the offshore wind project.

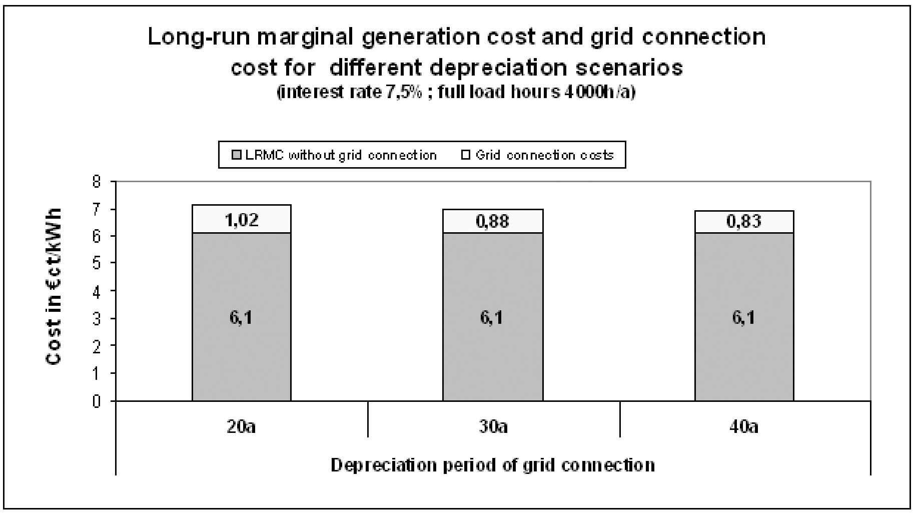
Table 2 Corresponding parameters and assumptions for grid connection

Project data – Kriegers Flak	
Investment	750 Mio.€
Installed capacity	350 MW
Expected generation	1386 GWh/a
Specific investment cost	2143 €/kW
Expected full load hours	3960 h/a
Connection length	121 km
Voltage level	150 kV
Assumptions	
Specific cable cost	350 €/m
Specific laying cost	150 €/m
Total costs for 2 × 150kV AC	121 Mio. €
Cost of offshore platform	25 Mio. €
Total grid connection cost	146 Mio. €
Specific grid connection cost	417 €/kW

4.1 *Different grid connection depreciation scenarios*

A separate depreciation of grid connection costs is possible when allocating RES-E grid connection to the grid infrastructure. This is important when using the grid assets beyond the lifetime of the wind turbines (e.g. in the case of re-powering). Figure 9 shows the results of different depreciation scenarios on grid connection costs for the planned *Kriegers Flak* offshore wind farm. Longer depreciation of grid connection results in lower overall project costs. This also slightly lowers the overall burden for the end-user, too.

Figure 9 *Kriegers Flak* offshore wind farm – Different depreciation scenarios for grid connection costs

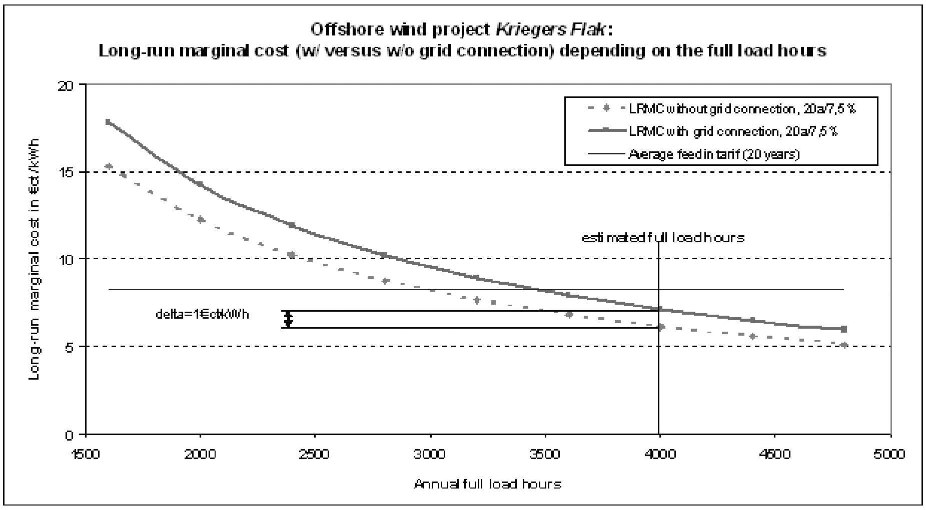


4.2 Adjustment of RES-E policy instruments

In Germany, offshore wind farms are supported by a feed-in tariff scheme according to the EEG-Gesetz (2004). The basic feed-in tariff of 6.19 €ct/kWh is guaranteed for 20 years. For wind farms installed before the end of the year 2010, an additional amount of 2.91 €ct/kWh will be available for 12 years at least. This period can be extended depending on the water depth onsite and the corresponding distance to shore. Taking into account several of these factors, for *Kriegers Flak* an average feed-in tariff of 8.2 €ct/kWh is calculated over 20 years.

When allocating grid connection costs to the grid infrastructure, feed-in tariffs have to be adjusted (i.e. decreased) to achieve the same offshore wind deployment (compared to the status quo). To quantify this effect, the Long-Run Marginal Costs (LRMC) of the *Krieger Flak* offshore wind farm are determined in either case depending on the annual full load hours, see Figure 10. In this scenario – where an interest rate of 7.5% over 20 years is assumed – the trade-off between the LRMC and the corresponding feed-in tariff is reached at 3500 full load hours. Estimated annual full load hours for the *Kriegers Flak* offshore wind project are slightly higher (around 4000 h/yr). When considering the LRMC without grid connection costs, a decrease of 12% of the feed-in tariff result in the same economic conditions for the wind developer.

Figure 10 *Kriegers Flak* offshore wind farm – LRMC with versus without grid connection costs depending on annual full load hours (average feed-in tariff according to the German EEG-Gesetz (2004))



Totally, if grid connection is considered as a part of the grid infrastructure and the corresponding costs are consequently allocated to the grid operator (and socialised via grid tariffs) then:

- the most productive wind resource sites are implemented and
- the learning curve for a wind offshore grid connection is accelerated.

A separate depreciation of grid connection costs enables longer depreciation periods (when taking into account that the grid assets still remain in the case of repowering), resulting in lower overall project costs. For offshore wind farms located far from shore, this may become even more beneficial from the wind developers' point-of-view.

5 Conclusions

In general, grid infrastructure issues address the entire natural monopoly in the electricity supply chain. For a large-scale intermittent RES-E integration, therefore, it is necessary to investigate both:

- grid connection to the existing grids (regardless of the distance and/or voltage level of connection) and
- grid extension/reinforcement measures elsewhere in the existing network due to changed load flows.

Moreover, considering the currently ongoing benchmarking and grid tariff regulation procedures in many European countries,[8] the implementation of correct cost allocation principles is vital. Not least due to these ongoing grid regulation procedures, it is essential to start a fundamental discussion on the allocation of both RES-E-related grid connection costs and grid extension/reinforcement costs. In the past, for small-scale RES-E integration, the share of grid-related costs has been small compared to the long-run marginal costs of RES-E generation. Therefore, grid-related costs have not been clarified, but often treated as part of the long-run marginal costs of the RES-E power plant and subsequently, were socialised via the corresponding RES-E promotion instrument.

But this practice clearly violates the unbundling principles of the EC-Directive (as well as the economic theory of network industries in general):

- Moreover, in countries such as Germany, it is still foreseen to allocate grid connection costs of (offshore) wind farms to the wind project and subsequently, to socialise corresponding costs via feed-in tariffs. This practice (mixing up costs of kWh's generated and grid infrastructure assets) is at least questionable.[9]
- On contrary, in countries such as Denmark, grid connection costs of (offshore) wind farms are already allocated to the grid infrastructure and socialised correctly.

Moreover, the results of the modelling examples based on the Green*Net* software show that – using currently implemented RES-E promotion instruments in different European countries and assuming in the BAU scenario that these instruments remain up to the year 2020 – the pattern of RES-E deployment significantly varies depending on the degree of unbundling and the allocation strategy of the different disaggregated cost elements of RES-E grid integration.

Again, in this context, the German renewable legislation is cited to refer to further inadequacies:

- On the one hand, still no market mechanisms are implemented for the provision of system balancing services (being clearly subject to competition). The Transmission System Operators (TSOs) are responsible for balancing the system apart from competitive elements.

- On the other hand, the corresponding costs for balancing the system are socialised via grid tariffs by the TSO. This practice, again, is at least questionable and supposed to be not arguable in the long run.

As a consequence of the inadequacies mentioned throughout this paper, it is recommended to establish a strategic EU-wide policy for a long-term, large-scale RES-E grid integration. In this context, a fundamental unbundling discussion is indispensable. This means in particular, that a re-definition of the interface between the RES-E power plant (incl. the 'internal grid' and the corresponding electrical equipment) and the 'external' grid infrastructure (i.e. new grid connection lines and extension/reinforcement of the existing grid) has to be discussed. This does not necessarily mean that the additional grid tariff component due to RES-E grid integration has to be paid by the local/regional end-users only. The costs can be socialised also within a 'grid infrastructure component' on national or even EU-level. Of course, corresponding accounting rules have to be established for the grid operators.

Finally, for acceptance of large-scale intermittent RES-E generation in a system, several existing barriers in the wholesale and balancing markets (including settlement procedures) have to be overcome. A critical review in this context is necessary in several EU Member States. In the short-term, improved wind forecasting tools are needed to reduce the impact of intermittency and, subsequently, balancing costs. In the long-term, however, it is also important to address demand response options to minimise additional system balancing requirements and costs.

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Notes

[1]On contrary, grid connection for biomass – in general – is not a crucial barrier, as the particular location of the plant is even more independent from resource conditions.

[2]In principle, there exist both options: (i) socialisation within a supply area of a grid operator or (ii) socialisation across the whole country (i.e. covering also several other grid operators).

[3]For a comprehensive discussion on the capacity credit, see the Appendix.

[4]The format of result presentation in $E2M2^s$ is compatible with the Green*Net* model. An iterative approach is used in modelling the interactions between the conventional power market ($E2M2^s$) and RES-E generation (Green*Net*). In a first step, RES-E deployment up to 2020 is modelled based on Green*Net* assuming a wholesale electricity price forecast derived from a $E2M2^s$ model run (using estimates on RES-E deployment from the literature). In a second step, RES-E projections and the residual request for the conventional power generation determined in Green*Net* are used as the input parameter for a new $E2M2^s$ model run. In a third step, an updated wholesale electricity price forecast again is used as an input for a new Green*Net* model run. This procedure is repeated iteratively until predefined deviations are acceptable (for details see e.g. Huber et al. 2004c).

[5]Taking into account the negative effects of the Water Framework Directive (EC, 2000) on electricity generation, the total electricity generation from large-scale hydropower can even be lower in 2020 compared to the status quo.

[6]Please note that comprehensive RES-E policy assessments as well as several dynamic interactions between RES-E generation, conventional electricity and CHP generation, energy efficiency measures on the demand side and GHG-reductions in the electricity sector in several EU27 countries can be modelled with the simulation software *Green-X*. *Green-X* has also been developed in recent years at Energy Economics Group (EEG) at the Vienna University of Technology, Austria (see Huber et al., 2004b and www.green-x.at). The common interface between Green*Net* ("RES-E infrastructure tool") and *Green-X* ("RES-E policy tool") is the database on potentials and costs of RES-E technologies in various countries and the RES-E

BAU policy settings. Finally, Green-*X* is also the software tool used in the recently finished EC-Project "FORRES 2020 – Analyses of the EU renewable energy sources' evolution up to 2020". For further details on FORRES 2020, please see Ragwitz et al. (2005).

[7]Note that in this context, just the grid extension/reinforcement costs on the existing grid infrastructure are addressed. Grid connection costs of wind farms to the existing grids are included in the long-term marginal generation costs. Therefore, a clear distinction in the '*wording*' is necessary in Section 3. In Section 4, the grid connection costs are analysed separately.

[8]That is, the determination of eligible costs for construction and operation of grids and, subsequently, the socialisation of corresponding costs via grid tariffs.

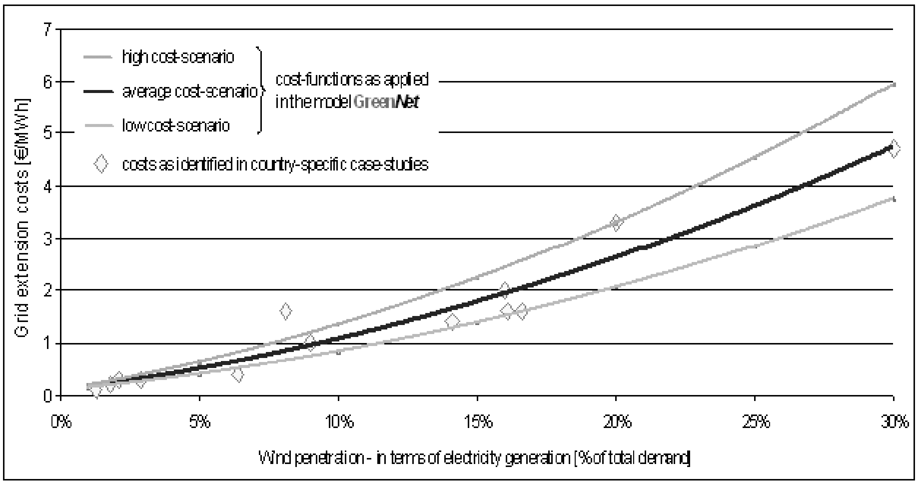
[9]In general, grid infrastructure assets (natural monopolies) are depreciated differently compared to the assets being subject to competition or feeding into competitive markets (like RES-E electricity generation).

Appendix: assumptions in the Green*Net* model

A.1 Assumptions on extra grid extension/reinforcement costs

Derived from the results of country-specific studies on the large-scale wind integration (based on detailed load flow analyses), the long-run marginal costs for grid extension/reinforcement allocated to wind penetration are identified. This set of data (determining grid extension/reinforcement costs as a premium per MWh wind generation and depending on wind penetration) is described in the Green*Net* model by a continuous mathematical function, see Figure A.1. Uncertainties are taken into account by implementing two alternative scenarios for high and low costs.

Figure A.1 Model implementation of additional grid extension/reinforcement costs caused by wind integration (expressed as a premium in €/MWh wind generation)



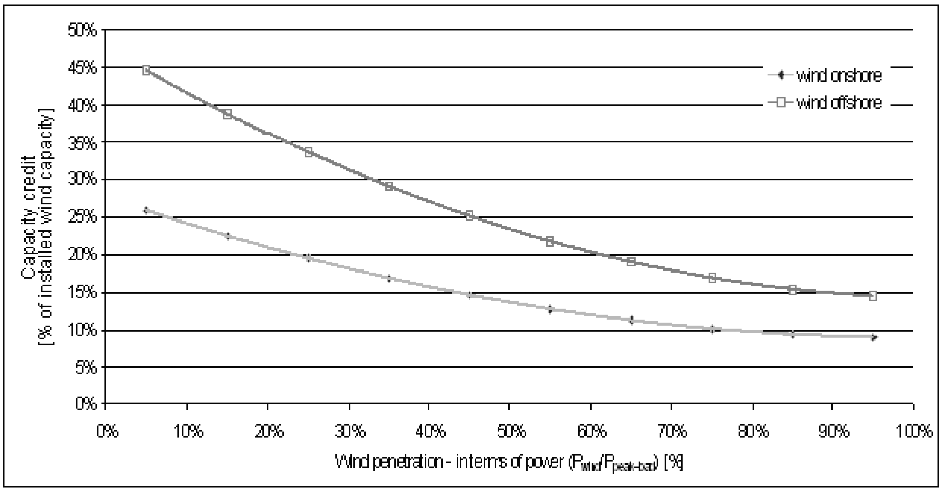
A.2 Assumptions on extra system operation costs

In the Green*Net* model, the costs for short-term system balancing allocated to the wind generation are derived from different country-specific case studies and literature. Depending on the wind penetration, they are in a range of 0–3€/MWh (for details see e.g. Auer et al. (2004)).

Long-term system capacity requirements and corresponding costs relate to the limited contribution that intermittent wind generation can make to system security. For small levels of the wind penetration in the system (i.e. more precisely, installed wind capacity compared to system peak load), the capacity credit for the wind generation is equivalent to the load factor. As the capacity of the wind penetration increases, wind becomes increasingly less reliable in a system for displacing the capacity of conventional plants – even in case of geographical spread of wind sites – as the system reliability is increasingly dominated by the wind. Therefore, the capacity credit begins to tail off (see e.g. also DEWI (2005), Auer et al. (2004), Pantaleo et al. (2003), ILEX (2002), Giebel (2001), Dany and Haubrich (2000)).

Figure A.2 quantifies the average capacity credit of wind onshore and offshore depending on installed wind capacity in a system. The results in Figure A.2 (indicating an average of several case studies analysed and being also implemented in the Green*Net* model) are derived from a comprehensive literature survey (publications cited above as well as others).

Figure A.2 Model implementation for the calculation of the capacity credit of wind (onshore and offshore)



The calculation of the additional system capacity costs in the Green*Net* model finally is based on the 'thermal equivalent' approach according to ILEX (2002):

> "The annual wind generation is calculated from the installed capacity in MW and the annual full load hours. Then the equivalent amount of conventional capacity is determined required to produce the same annual electricity, assuming a Combined Cycle Gas Turbine (CCGT) at an average load factor. However, conventional capacity can be viewed as delivering two services, energy and capacity. If it is considered that the wind provides no contribution to capacity margin, then to be equivalent to conventional generation, wind would require back-up from equivalent conventional capacity. This capacity could come from a number of sources, including old conventional and pumped-hydro generation, new CCGTs or new Open Cycle Gas Turbines (OCGTs). For the cost calculation the capacity requirements are allocated to new, but not leading-edge OCGT, suitable for peaking operation, considering that at the margin only OCGTs will be used, as any economically feasible existing generation would already be utilised on the system. The annualized capital costs are finally determined depending on annual wind generation. If it is considered that wind does contribute to system security, albeit at a smaller rate than conventional capacity, then the above capacity requirement is reduced by the level of that contribution. Then also the annualized capacity costs are derived depending on annual wind generation."