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Synthesis of Results on Least-Cost RES-E Grid Integration

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1 INTRODUCTION

The EC-Directive 2003/54/EC (repealing EC-Directive 96/92/EC) on liberalization of electricity markets requires the electricity supply industry to be competitive, yet realizes that many elements of the electricity supply chain are still natural monopolies (EC (2004)). 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 unbundling, which is one of the cornerstones of the liberalized electricity market. Separation of the competitive segments electricity generation and customer supply from the grid infrastructure is seen as a precondition for non-discriminatory grid access of third parties (e.g. RES-E generators) as well as for transparent grid regulation procedures and grid tariff determination.

But legislation and definition of RES-E policy goals on national as well as EU level still face a variety of lacks and inconsistencies (see e.g. Auer et al (2006)):

- mixing up demarcation lines between the RES-E power plants and the grid infrastructure (new grid connection lines, reinforcement/upgrading of the existing grid) as well as overall system operation,
- neglecting disaggregated cost allocation of RES-E grid integration and, subsequently
- mixing up different instruments for remuneration of the different disaggregated cost elements (RES-E promotion instruments versus wholesale/balancing markets versus grid tariffs).

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

- In the short-term (times scales below seconds to several hours) a variety of balancing (ancillary) services are necessary for maintaining stable system operation. The driver for short-term system balancing requirements is the magnitude of random power fluctuations, caused by unpredictable changes in both generation and load.
- In the long-term, in competitive electricity markets the market itself shall be responsible for providing generation adequacy. This is also true for systems with large amounts of intermittent wind generation.

Large-scale RES-E grid integration, furthermore, also has to be analysed from the grid operator's point-of-view. At present, in many EU Member States¹ new grid regulation models are implemented. These new models shall, on the one hand, provide incentives for grid operators for efficient grid operation and grid asset management and, on the other hand, define transparent procedures for grid tariff determination. Since the grid regulation process is accompanied by benchmarking of eligible costs for grid operation and grid infrastructure

¹ On the one hand, sophisticated grid regulation models are already implemented in countries like UK, The Netherlands, or Austria. On the other hand, in countries like Germany the public discussion on the implementation of new grid regulation models and grid tariff determination procedures just begun (mainly due to the fact that the installation of a sector-specific energy regulator has been delayed for years).

planning, the grid operator naturally has to be confident that several additional costs of large-scale RES-E grid integration are eligible in this context. This is, at present, not necessarily the case. Therefore, the willingness of grid operators to absorb – exogenously saddled – RES-E generation technologies is limited.

The discussion above indicates that large-scale RES-E grid integration has a variety of dimensions. Neither in practise nor in literature many open questions in this context have been addressed and/or solved. Moreover, the necessity of a convergence of different policies (e.g. RES-E promotion policy and grid regulation policy) seems to be not obvious at present. On the contrary, literature on critical reviews of unbundling in the context of large-scale RES-E grid integration is scarce. The most comprehensive empirical overview study on RES-E grid connection charging in the “old” EU15 Member States is conducted in Knight et al (2005). A few conceptual papers on strategic approaches on grid infrastructure planning (and operation) in the context of large-scale RES-E grid integration exist (e.g. Auer et al (2006), Soeder/Holttinen (2006), Dowling/Hurley (2005)). On country level corresponding publications exist e.g. for The Netherlands (Hooft (2003)), Denmark (Bach (2004)), UK (ILEX (2002)), Ireland (Smith (2004)) and Germany (Dena (2005)). But only a few of them explicitly address separation of RES-E (wind) grid connection and alternative approaches on cost allocation. At present, DTI (2006) and Jamasb et al (2005) finally are one of the few publications addressing the interdependences of RES-E grid integration policies and the grid regulation process, notably as far as the UK electricity market is affected.

The major objective of this report is to comprehensively discuss several dimensions of correct unbundling, on the one hand, and strategies for least-cost RES-E grid integration, on the other hand. Moreover, currently existing demarcation lines between the RES-E power plant, the grid infrastructure and overall system operation are questioned. Furthermore, recommendations are derived on how to achieve a convergence on different RES-E related and grid related policies with special emphasis on the grid operator’s point-of-view. In this context it is shown that there exist partly conflicting interests in cost remuneration for different market actors (RES-E developer, grid operator, system operator). Finally, recommendations are derived on how to integrate a maximum on RES-E generation with lowest cost for society.

The report is organised as follows:

- Section 2 addresses the relevance of unbundling for large-scale RES-E grid integration. In this context the grid infrastructure plays a core role. Besides the challenges faced by the RES-E developer and the grid operator also the cost allocation schemes of RES-E grid integration in Europe are discussed comprehensively.
- In section 3 the key results of selected RES-E grid integration case studies are analysed and discussed. Moreover, best practise criteria are derived under a variety of different constraints and energy policy settings.
- Section 4 discusses the results on least-cost RES-E grid integration derived from the simulation model *GreenNet*. Moreover, *GreenNet* also models different cost allocation schemes of disaggregated RES-E grid integration, taking into account also the intermittent nature of RES-E generation.
- Finally, section 5 derives policy recommendations and conclusions for decision makers on large-scale least-cost RES-E grid integration.

2. THE RELEVANCE OF UNBUNDLING FOR LARGE-SCALE RES-E GRID INTEGRATION

2.1 The role of the grid infrastructure

2.1.1 Challenges for RES-E developers

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 up-front, 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-hydro power (Resch et al (2003)). On contrary, grid connection for biomass or biogas – in general – is no crucial barrier as the particular location of the plant is even more independent from resource conditions. 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 and the costs are socialized in the grid tariffs, then the initial burden does not fall on the RES-E developer.

Besides new grid connection lines (regardless of the distance and/or voltage level of connection) also grid reinforcement/upgrading measures may be necessary elsewhere in the existing network due to large-scale RES-E (wind) integration. But the allocation of the corresponding grid reinforcement/upgrading costs to the RES-E developer is ambiguous. The core problem is that any changes in an intermeshed grid infrastructure will change the load flows in the system. The status quo as well as changes of load flows, however, have a variety of dimensions, as there are e.g. changes in generation and load centres, bottlenecks, or power trading activities. Therefore, the allocation of load flow changes to one single event (e.g. grid reinforcement/upgrading caused by new RES-E (wind) integration) is not necessarily correct.

Moreover, considering the currently ongoing benchmarking and grid tariff regulation procedures on the transmission and distribution grids in many European countries correct cost allocation of grid infrastructure elements in the context of RES-E grid integration is crucial. Then only, correct grid tariff determination is practicable in the new models being implemented at present.

2.1.2 Challenges for grid operators

In literature, large-scale RES-E grid integration has not been analysed from the grid operator's point-of-view so far. Moreover, the challenges faced by grid operators in bearing their additional RES-E grid integration costs have to be addressed not least due to the following two currently ongoing developments (being not linked together at present):

- rapidly increasing shares of RES-E grid integration in the European transmission and distribution networks, and
- implementation of new grid regulation and grid tariff determination models by national regulators accompanied by benchmarking of eligible costs for grid infrastructure planning and grid operation.

Moreover, electricity grids are capital intensive infrastructures characterized as natural monopolies over a defined geographic and/or voltage region. The grid assets' life-times can

be up to 40 years and once investments are made they are effectively sunk. Therefore, grid assets are vulnerable to changes in regulatory conditions which could prevent or hinder cost recovery. In particular, RES-E promotion policies not directly taking into account effects on grid operations can impose costs on transmission and distribution grids and give rise to the question of cost recovery. At present, from the grid operator's point-of-view these uncertainties are significant economic disincentives to absorb large-scale RES-E generation technologies into their grids.

In order to overcome these existing inadequacies – and also to satisfy the grid operator's future expectations on investment cost recovery in the context of RES-E grid integration – a convergence in the design of both RES-E promotion policy and grid regulation policy² is supposed to be indispensable. A precondition for a harmonised policy is serious unbundling, i.e. to rethink the definition of the demarcation lines between the RES-E power plant (often characterised by local availability in remote areas) and the grid infrastructure.

More precisely, an explicit ex-ante mechanism has to be created in the grid regulation process for identifying and remunerating any asset stranding or new investment requirements in the grids (grid connection, grid reinforcement/updates) caused by policies promoting RES-E generation technologies. This is the so-called “shallow” RES-E grid integration cost approach (see also Figure 1). In this case, neither the RES-E developer (causing increased investment requirements) nor the grid operators (facing these challenges) bear the costs directly. The knock on effects are directly allocated to the grid tariffs and finally borne by the end-users. In this scenario it can be argued, furthermore, that the additional investments into the grids also improve security of supply and finally – from a system-wide perspective – this may be the overall least-cost approach taking into account also several aspects beyond RES-E grid integration only.³

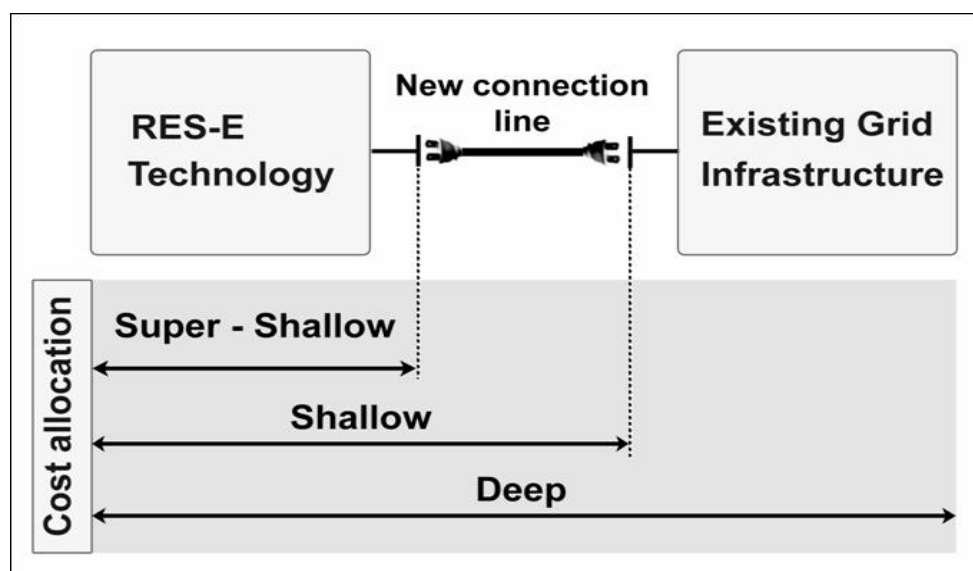


Figure 1: Grid connection of new RES-E generation technologies: “deep” versus “shallow” grid integration cost allocation approach.

² Different grid regulation models describe the different approaches to identify the eligible costs for grid infrastructure planning and grid operation and to translate these costs into grid tariffs. For details on different grid regulation models see e.g. Auer (2002).

³ Note, that only a few EU Member States currently have implemented a “light” version of the “shallow” RES-E grid integration cost approach (details see Table 1). This means in particular, that the RES-E grid connection costs are still allocated to the RES-E power plant and, therefore, endogenously covered by the corresponding RES-E promotion instrument.

On contrary, in the so-called “deep” RES-E grid integration cost approach, the RES-E developer bears at least the grid-infrastructure related RES-E integration costs (see also Figure 1). The RES-E developer is encouraged to make the locational decision on the RES-E power plant site having the least negative knock on effects on grid operators. This approach does not cause significant disincentives for the grid operator. The “deep” RES-E grid integration cost approach (currently favoured in many EU Member States; details see Table 1) will, however, discourage investments into RES-E generation technologies relative to the scenario where RES-E developers do not have to take into account corresponding knock on effects (i.e. “shallow” RES-E grid integration).

Previous paragraphs obviously show the dilemma for policy making:

- If the RES-E policy aim is to maximise the amount of RES-E generation technologies in the system by a target date, then taking into account also the extra costs imposed on electricity grids by making the RES-E developers pay for them may, hence, not favour the first best resource availabilities (“deep” cost approach).
- If the grid regulation policy aim is to overcome the grid operator’s economic disincentives of asset stranding caused by large-scale RES-E grid integration and, subsequently, to maximise the amount of RES-E generation technologies in the system by a target date, then the extra RES-E related grid integration costs have to be socialised in the corresponding grid tariffs (i.e. correct and strict unbundling) being finally paid by the end-users (“shallow” cost approach).

2.1.3 Basic principles of cost allocation for RES-E grid connection and grid reinforcement/upgrades

Integration of RES-E generation technologies into the existing distribution and transmission grids expects new grid connection lines as well as reinforcements/upgrades of the existing grid infrastructure (see Figure 2).

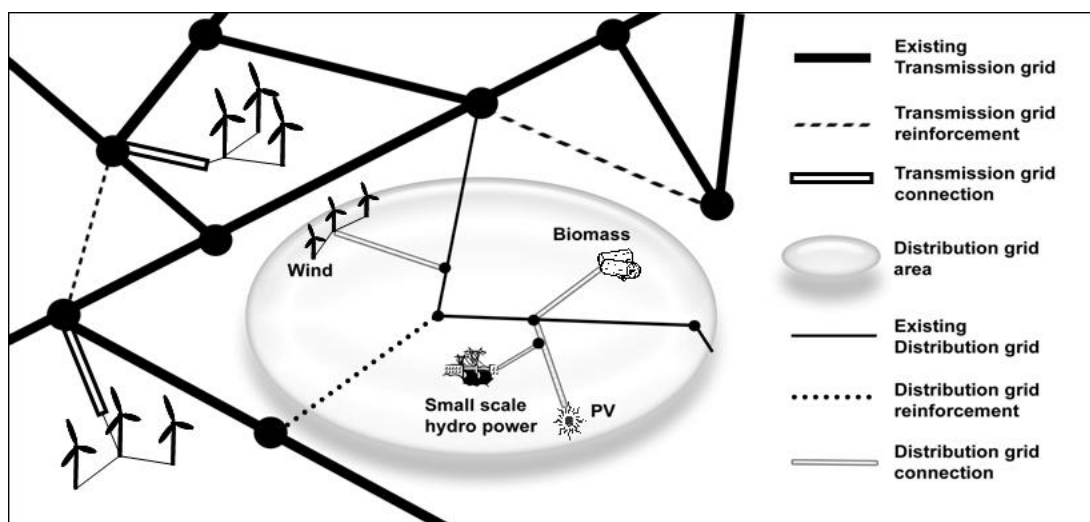


Figure 2: Grid connection and grid reinforcement/upgrading measures on distribution and transmission level caused by large-scale RES-E grid integration.

Whereas the identification of new grid connection lines and the allocation of the corresponding costs are no problem in an intermeshed grid infrastructure, the allocation of grid reinforcement/upgrading measures and costs to a single new RES-E generation

technology is ambiguous. In detail, the situation on distribution and transmission level is as follows:

- **Distribution grid:** If many RES-E generation technologies are connected, bottlenecks may arise in the existing distribution grid due to changes in load flows. Distribution grid reinforcements/upgrades can, subsequently, eliminate these bottlenecks.
- **Transmission grid:** A similar situation occurs on the transmission grid. The core problem here is that any changes in an intermeshed grid infrastructure will change the load flows in the system in general. The status quo as well as changes of load flows, however, has a variety of dimensions, as there are e.g. changes in geographic distribution of generation and load centres, bottlenecks in peaking periods, or power trading activities. Therefore, the allocation of load flow changes and, subsequently, grid reinforcement/upgrading measures to the integration of a single new RES-E generation technology is questionable.

In recent years a variety of empirical country-specific studies have been carried out addressing grid reinforcement/upgrading requirements and costs caused by large-scale RES-E grid integration. In order to be able to derive comparable grid reinforcement/upgrading costs from different studies in literature a common methodology is used:⁴

- **Distribution grid:** Several grid reinforcement/upgrade measures and costs are allocated to the corresponding RES-E generation technologies directly.
- **Transmission grid:** Only parts of the grid reinforcement/upgrading measures and costs are allocated to the corresponding RES-E generation technologies directly. The reason is that also other market players (incumbent utilities, power traders, grid operators, system operators, end-users) significantly benefit from these additional transmission capacities. Availability of additional transmission capacities beyond RES-E generation occupancy mainly depends on the geographic distribution of generation and load centres and the share of RES-E generation (compared to total electricity generation) in a particular region. Figure 3 below presents the results on the comparison of country-specific transmission grid reinforcement/upgrading costs for different shares of wind penetration in different European countries.

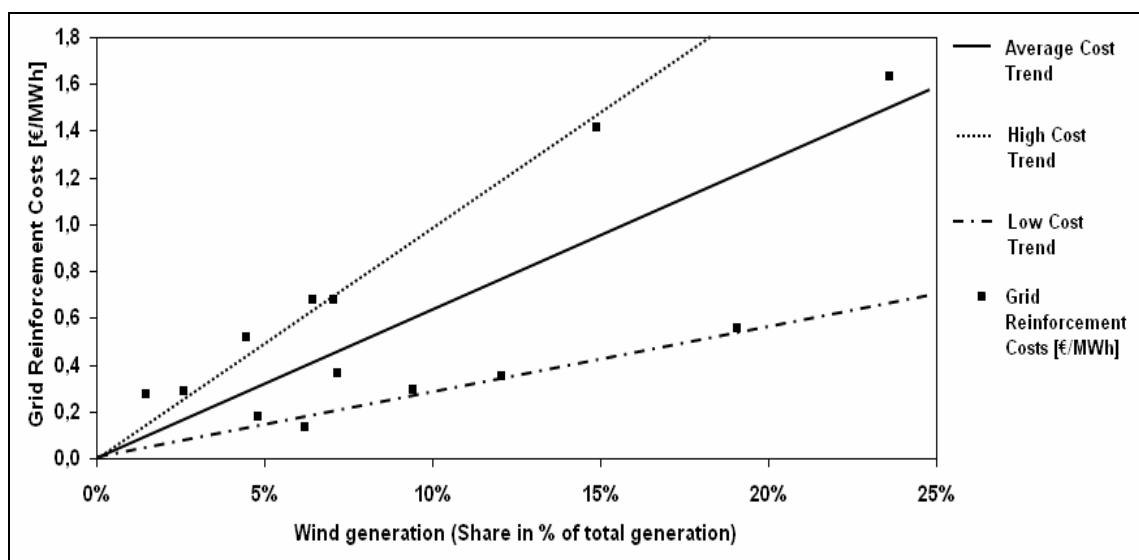


Figure 3: Country specific transmission grid reinforcement/upgrading costs for different shares of wind penetration (in €/MWh_{Wind}).

⁴ A standardized calculation method expects the following assumptions: Interest rate: 7.5%. Depreciation of grid infrastructure assets: 40 years. Average full-load hours of wind generation (if not given in the study) 2,000 h/yr and 4,000 h/yr for wind-onshore and wind-offshore respectively. Currency conversion rates: average exchange rates in the year of publication of the study.

2.1.4 Status quo of RES-E grid integration cost allocation schemes in Europe

The textbooks in economic theory expect to allocate both RES-E grid connection costs and grid reinforcement/upgrading costs to the grid infrastructure and to spread (socialize) these costs through the transmission and distribution tariffs (and not to include either of these two cost components to the RES-E project costs and recover them in the corresponding RES-E promotion instruments).

In practice, however, several grid-related cost components (or at least the grid connection costs) are still allocated to the long-run marginal generation costs of the RES-E power plant in almost all European countries (see Table 1). An entire separation of the grid infrastructure and the RES-E power plant (“super-shallow” cost allocation approach) is not implemented in the EU Member States at present (exception is Denmark on transmission grid level).

Table 1: Status quo of different RES-E grid integration cost allocation schemes in the ‘old’ EU15 Member States (“deep” vs “shallow” vs “hybrid”). Source: Knight et al (2005).

	RES-E grid integration cost allocation scheme	Max. grid connection cost	Cost transparency
Austria	Deep	10% of investment	Low
Belgium	Shallow	5-10% of investment	High
Denmark	Shallow	5-10% of investment	High
Finland	No Standard	-	Medium
France	Hybrid	10-20% of investment	Medium
Germany	Shallow	-	Low
Greece	Deep	-	Low
Ireland	Deep	3-8% of investment	High
Italy	Deep	-	Low
Luxembourg	Deep	-	Low
Netherlands	Shallow	-	High
Portugal	Deep	15% of investment	Medium
Spain	Deep	-	Low
Sweden	Deep	10% of investment	Low
UK	Hybrid	8-12% of investment	High

In some of the remaining European countries the existing pattern may also change in the next years, not least due to the currently ongoing benchmarking and grid regulation procedures being conducted by national regulators. Although these procedures are driven to fulfill the unbundling principles of the EC-Directives 2003/54/EC and 96/92/EC (and to implement cost transparency into grid infrastructure charging in general) rather than by RES-E grid integration, finally, the existing demarcation lines between the RES-E power plant and the grid infrastructure may be shifted increasingly towards the RES-E power plant (i.e. strict “shallow” or “super-shallow” integration cost approach). On contrary to the “deep” integration cost approach this guarantees perfect cost transparency and, furthermore, fulfils the basic unbundling principles.

2.1.5 Challenges for future wind-offshore grid connections

In the next few years there exist plans to connect a variety of ambitious offshore wind projects to the European transmission grids. At present, however, large-scale offshore wind generation cannot be integrated into the existing European transmission grids mainly due to weak connection points near shore. Moreover, without a common trans-national strategy for an offshore extension of the European transmission grid suboptimal integration of offshore wind projects into the existing electricity systems is possible only in the long-term.

Figure 4 presents an approach on a common strategy for an offshore extension of the transmission grid in Northern Europe. A common trans-national European offshore transmission grid has to be equipped with offshore platforms, collecting the individual connection lines of the different offshore wind farms,⁵ on the one hand, and conducting voltage transformation before feeding wind generation into the high voltage transmission grid, on the other hand. In order to reduce transmission losses, high voltage levels (400 kV) are favoured for increasing distance to shore. Therefore, beyond 50 km offshore the technology set shown in Figure 4 is obligatory (i.e. robust single, dual or multiple AC grid connection lines and offshore platforms including transformer stations).

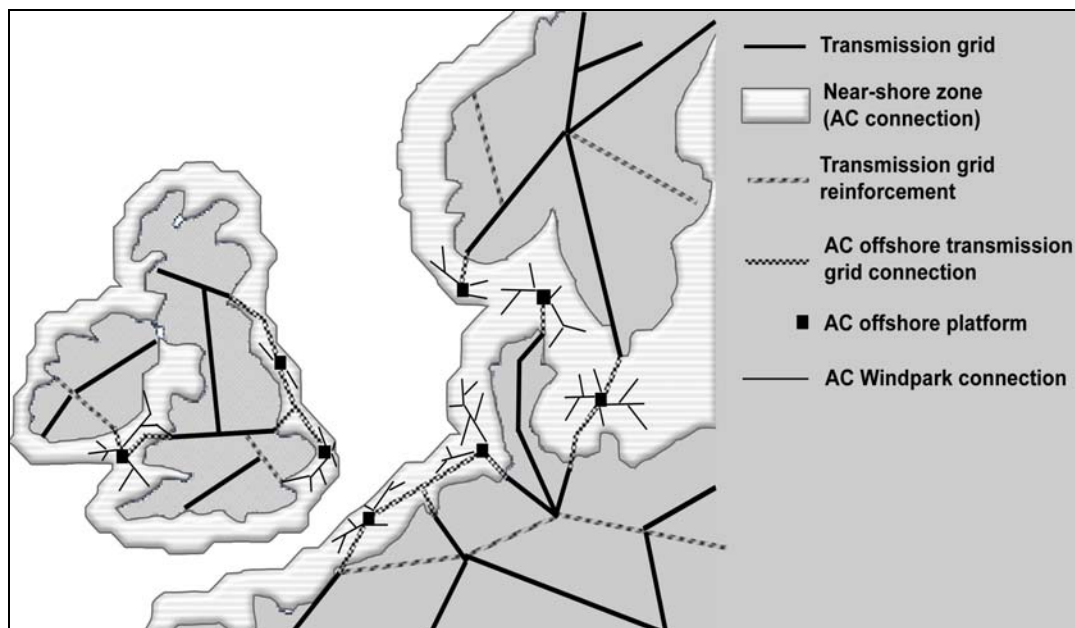


Figure 4: Common trans-national strategy for an offshore extension of the transmission grid in Northern Europe. Source: Prügler et al (2006).

Empirical data on grid connection costs for offshore wind projects are scarce. Besides the distance to shore – determining the grid connection technology (w/ versus w/o offshore platform and transformer station) – also the size of the offshore wind farm significantly determines the grid connection costs.

Finally, for completeness it is also mentioned, that there also exists the vision – when addressing time scales beyond the year 2030 – of a European Offshore Supergrid™ (see e.g. O'Connor (2006)). The major purpose of such an Offshore Supergrid™ is to connect several offshore wind farms across geographically separated European sea regions and, doing so, smoothing aggregated offshore wind generation. Covering large sea regions (North Sea, Baltic Sea, Mediterranean Sea) it is most likely that wind speeds are significant at any instant somewhere. A European Offshore Supergrid™, furthermore, links several existing synchronous European transmission systems (UCTE-system, Nordel-system, UK-system) and, therefore, contributes significantly to stable system operation and enables also any commercial activities like power trading. For further details in this context it is referred to O'Connor (2006).

⁵ Except offshore wind farms located near shore (< 25 km). They are usually connected directly to the existing transmission grid onshore, using low-cost AC connection lines.

2.2 System operation and large-scale intermittent RES-E generation

Large-scale intermittent RES-E integration into the existing electricity systems expects – besides reinforcements/upgrades of the grid infrastructure – also a variety of additional measures on overall system operation. The management of the intermittent nature of RES-E (wind) generation is one of the major challenges in this context. At present, large electricity systems operate mainly without advanced energy storage technologies (except those systems with large capacities of pumped hydro-storage plants). Therefore, at any instant, output from several electricity generators has to be controlled to equal total load. For these reasons, system operators have to forecast generation and load on timescales from seconds to years and have methods to control the balance continuously.

Therefore, robust approaches are necessary to estimate the additional system-related requirements and costs for stable system operation. Moreover, there are still many open questions, as there are e.g.

- where to allocate the corresponding system operation 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 (times scales below seconds to several hours) a variety of balancing (ancillary) services are necessary for maintaining stable system operation. The driver for short-term system balancing requirements is the magnitude of random power fluctuations, caused by unpredictable changes in both generation and load. System frequency is the parameter used to indicate the balance between generation and load and must be maintained continuously within narrow statutory limits around 50 Hz. With no change in generation, system frequency decreases when load is higher than generation and increases when generation is higher than load. In order to manage frequency effectively, system operators utilise a range of balancing (ancillary) services operating according to different time horizons and predominantly involve changes in generation rather than load (see e.g. van Werven et al (2005)).⁶

In the long-term, in competitive electricity markets the market itself shall be responsible for providing enough generation capacities being able to meet peak demand in the system. This is also true for systems with large amounts of intermittent RES-E generation. Nevertheless, long-term analyses estimate the capacity contribution of intermittent RES-E generation (wind in particular) on system level. Although wind generation throughout a national network makes some contribution to assured capacity, this contribution is significantly less than for equivalent conventional generation or non-intermittent RES-E generation. The relevant parameter in estimating the system capacity requirement caused by intermittent wind generation is the capacity credit (see e.g. Giebel (2001) and Giebel (2006)). More precisely, the capacity credit is the amount of capacity of conventional or non-intermittent RES-E generation that can be displaced by intermittent wind capacity whilst maintaining the same degree of system security. Roughly the capacity credit is equal to the average capacity factor of wind generation at low wind penetrations, but decreases with increasing wind penetration in a system.

⁶ At present, in different EU Member States a variety of different schemes exist for the allocation of corresponding balancing costs.

In the last decades a number of studies have been carried out aiming to quantify the capacity credit of wind generation in different electricity system configurations. When analyzing the results from different studies it is important to note that – due to the different modeling approaches and assumptions – it is not permitted to directly compare the published numbers. In Ensslin et al (2006) a structured description of the different approaches is presented and the impact of parameter variations on the capacity credit of wind generation is analyzed. The results clearly indicate that variations of the major input parameters like LOLP, spatial distribution of wind sites and the wind year considerably influence the resulting capacity credit in the different electricity systems.

Further lessons learnt from different sources in literature are (see also Figure 5)):

- the capacity credit of wind generation is in the range of the average capacity factor of wind generation at low wind penetrations in a system but decreases with increasing wind penetration, and
- for robust estimates of the capacity credit of wind generation data quality is essential. Therefore, mainly studies from recent years have been used since wind data quality has been improved considerably.

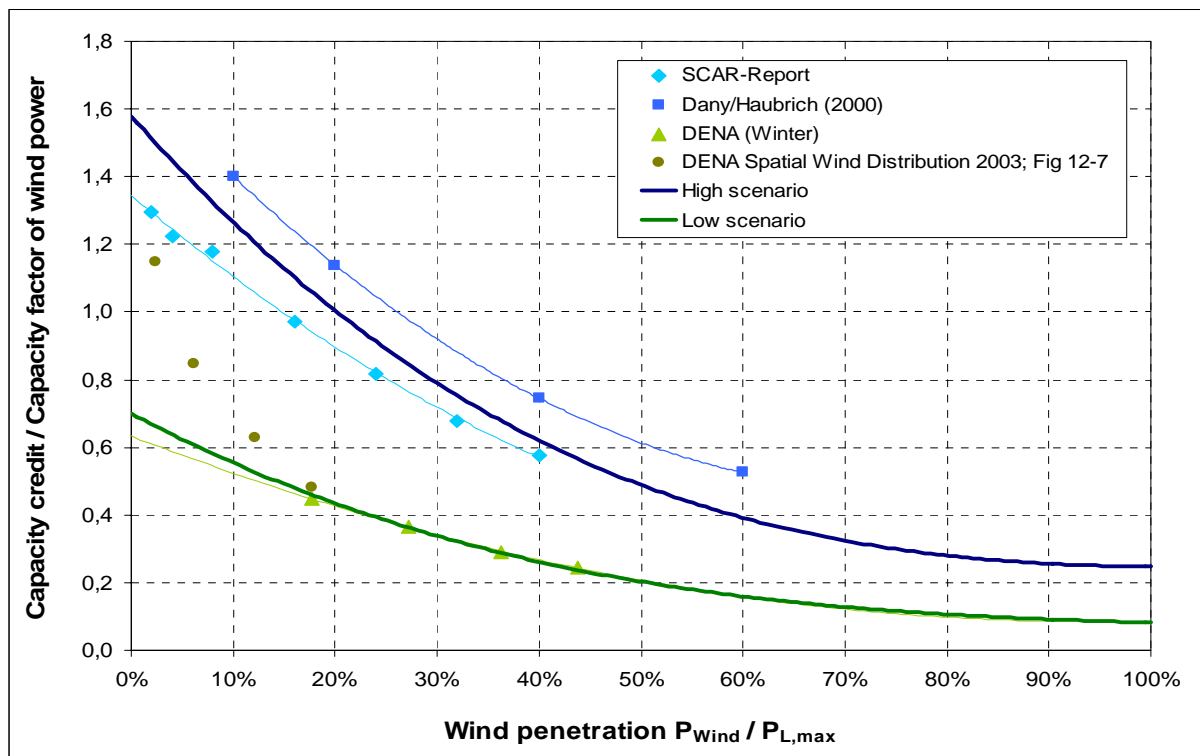


Figure 5: Estimated capacity credit of wind generation depending on wind penetration in the system based on different studies (incl. upper and lower bound scenario). Sources: ILEX (2002), Dany/Haubrich (2000), Dena (2005).

3 KEY RESULTS OF RES-E GRID INTEGRATION CASE STUDY ANALYSES

3.1 Overview on bandwidth of RES-E grid integration costs

The conditions and costs for integrating RES-E generation technologies into an existing grid can form significant barriers for the deployment of future RES-E generation. In order to analyze these barriers this chapter summarizes the outcomes of a comparison of conditions and costs for RES-E grid integration in selected European countries (for details see in the WP5-report “Case Studies on conditions and costs for RES-E grid integration” of the project GreenNet-EU27). The selected countries are: Germany, The Netherlands, United Kingdom, Sweden, Austria, Lithuania and Slovenia. Hence, a wide range from established liberalized electricity markets is considered. Based on literature reviews and stakeholder interviews country specific case study results for wind-onshore and wind-offshore, biomass and photovoltaic are presented. It is shown that especially in case of wind-offshore the allocation of grid integration costs can form a significant barrier for the installation of new installations as long as the RES-E developer has to bear all those costs (especially the so called “deep” costs).

It is a well known fact that the costs for RES-E grid integration are highly dependent on the point of connection, the characteristics of the grid at the connection point and, more generally, on the definitions used and the system boundaries considered. The cost figures presented in the following Table 2 are based on country specific case studies with harmonised definitions. Thereby three cost categories are distinguished for describing the costs of the RES-E technologies:

- shallow grid integration costs;
- deep grid integration costs;
- other fixed and variable costs.

It may be noted that all three categories can have both investment costs (expenses that occur only once in a project, mostly at the beginning) and annual costs occurring due to operation and maintenance. The three cost categories are described below, taking the case of wind as an example:

- Starting with the investment costs excluding grid integration costs, for most components it is clear that they are not part of the grid integration costs: foundation, tower, nacelle and rotor clearly belong to the investment costs. Not so trivial is the attribution of electric equipment that is used for realising the grid integration. Usually electric power control and quality are dealt with by components in the turbine. Nevertheless, here all equipment that is purchased with the wind turbine is considered to be part of the other costs. This also includes the cable from the turbine to a central connection plug in the wind park.
- The connection plug however is treated as a component of grid integration costs. All costs related to this central connection point are considered as “shallow” grid integration costs, including the power line from the connection plug to the connection point in the existing grid (thus including any transformers, road or river crossings). These “shallow” grid integration costs are influenced strongly by the distance to the nearest grid connection point that may eventually lead to a wide cost range of specific case studies.
- Finally, all expenses in the existing grid related to the connection of the new wind power plant are considered to be “deep” grid integration costs. Especially in case of wind power, being intermittent, grid reinforcements and upgrades can have an important financial

impact. These “deep” grid integration costs are however seldom subject to reporting. For this reason, the case studies summarised below focus on the “shallow” grid integration costs only and neglect any “deep” grid integration costs.

First requirement for compiling case studies reporting on costs of RES-E grid integration projects is the access to relevant data. Basically, two approaches have been applied: (i) literature research and (ii) interviews with relevant stakeholders. The general problems with these approaches are that grid integration costs are often not specified separately or if they are it is not always clear what costs are actually considered as grid integration costs. It is, furthermore, important to note that the analysis of specific RES-E case studies obviously leads to the problem that the grid integration costs are site-specific: they depend on the distance to the existing grid, on the trajectory and on the voltage level, to name a few influencing factors. Another problem is the difference between projected and realized costs. This is of special importance in case of wind-offshore as nearly no such project has yet been realized in the considered countries. To overcome some of the problems mentioned above several case studies have been analyzed for each RES-E technology and country resulting in a bandwidth of RES-E grid integration costs, see Table 2.

Table 2: Bandwidth of RES-E grid integration costs in the year 2004 (in EUR/kW)

Country	Wind power				Biomass		Photovoltaic	
	Onshore		Offshore		Min	Max	Min	Max
	Min	Max	Min	Max				
Germany	47	167	185	602	-	-	-	-
The Netherlands	40	150	180	203	99	-	0	100
The United Kingdom	94	130	-	-	-	-	54*	-
Sweden	85*	-	-	-	-	-	-	-
Austria	210*	-	-	-	28*	-	-	-
Lithuania	34*	-	-	-	-	-	-	-
Slovenia	-	-	-	-	14*	-	124	987

* One case study only.

Table 2 shows that there is in fact a wide range of grid integration costs. However, there are only slight deviations between the considered countries.

- Regarding wind-onshore the case studies for Austria and Lithuania constitute notable deviations. In case of Austria the deviations are due to a specific case study in the Alpine region with an unusual cable length of about 21 kilometres connecting the considered wind park to the closest connection point of the existing network. In case of Lithuania the deviations are due to a specific case study with a very suitable location regarding the grid integration costs.
- Regarding wind-offshore more deviations can be seen. Those are mainly due to the considered case studies for the Netherlands being nearer to the shore than the cases considered for Germany (there are no such sites near shore) and that all the considered case studies are based on projected costs only.
- Regarding biomass the deviations are due to the case studies being highly site specific and as for each country (except NL) only one study has been analyzed. Note that the German case study also includes the investigation of biogas power plants. However, as the electricity generation and grid connection costs are not comparable with solid biomass cases they are not presented in this comparison.
- Finally, regarding photovoltaic the deviations are due to the fact that the Slovenian cases include the inverter costs in the grid integration costs while in the case studies of the

United Kingdom and the Netherlands such costs are included in the other costs (closely following the definitions of the different cost components above).

3.2 Discussion of a selected offshore-wind case study (Kriegers Flak, Germany)

According to current legislation in Germany (Renewable Energy Sources Act (EEG (2004)) several grid connection costs of wind farms are allocated to the RES-E developer, whereas grid reinforcement/upgrading 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. Implementing the unbundling principles in a consistent manner, however, means that several grid related costs, both grid connection and grid extension/reinforcement, shall be allocated to the grid operator and socialized as a use-of-system charge via grid tariffs.

In the following, the consequences of consistent cost allocation are discussed by analysing a planned offshore wind project in the Eastern Sea of Germany: *Kriegers Flak*. The location is the Northeast of *Wittow* peninsula (see Figure 6). 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 €750m. Annual generation is assumed to be around 1400 GWh. The nearest fitting point for grid connection is *Bentwisch*, being 121 km far from the offshore site. Grid connection is realised with two 150 kV undersea cables, see Table 3.

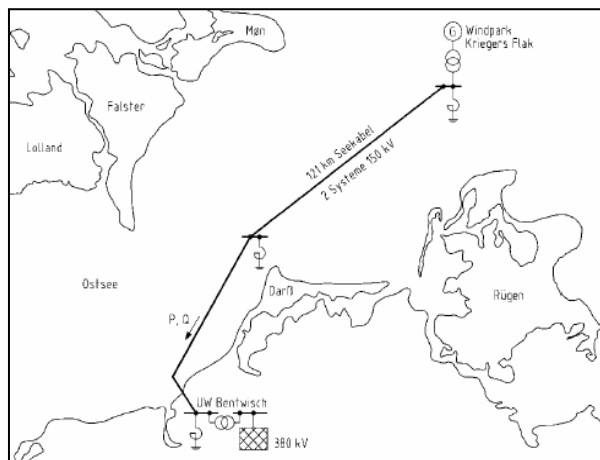


Figure 6: Offshore wind project *Kriegers Flak*.

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 2x150kV AC	121	Mio. €
Cost of offshore platform	25	Mio. €
Total grid connection cost	146	Mio. €
Specific grid connection cost	417	€/kW

Table 3: Corresponding parameters and source: Offshore Forum Windenergie www.ofw-online.de

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

3.2.1 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 7 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.

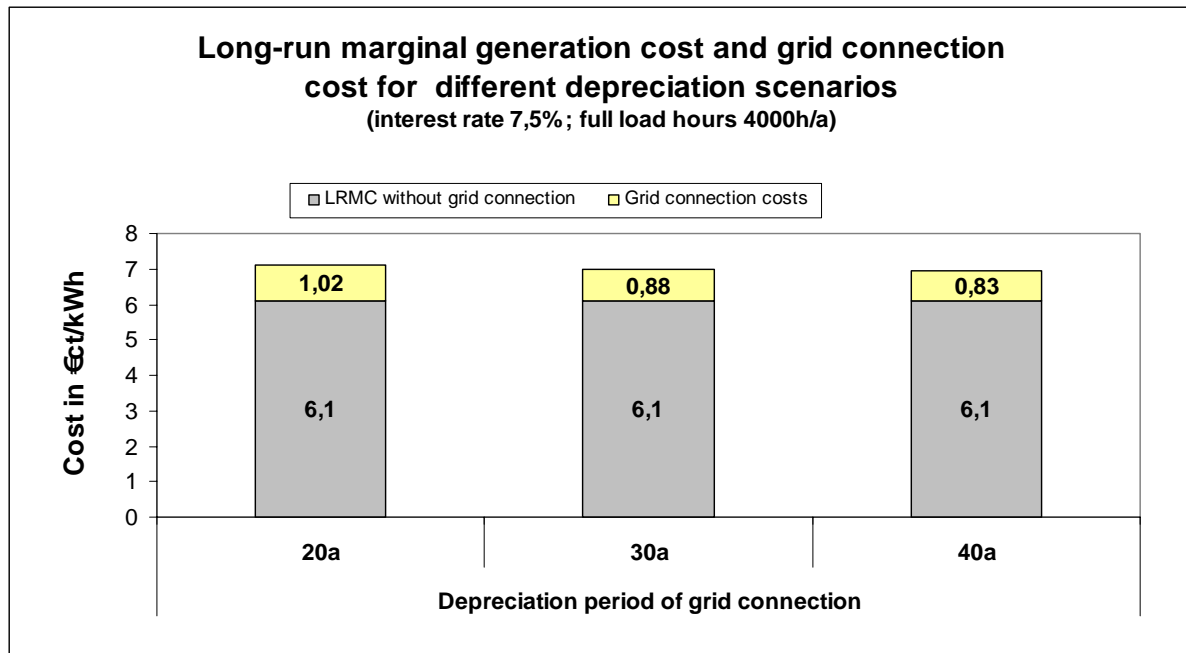


Figure 7: *Kriegers Flak* offshore wind farm - Different depreciation scenarios for grid connection costs.

3.2.2 Adjustment of RES-E policy instrument

In Germany, offshore wind farms are supported by a feed-in tariff scheme according to the EEG (2004). The basic feed-in tariff of 6.19 €/kWh is guaranteed for 20 years. For wind farms installed before the end of 2010 an additional amount of 2.91 €/kWh is 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 €/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 8. 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.

Summing up, if grid connection is considered as part of the grid infrastructure and the corresponding costs are consequently allocated to the grid operator (and socialised as a use-of-system charge via grid tariffs) then:

- the most productive wind resource sites are implemented, and
- the learning curve for 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 case of re-powering), resulting in lower overall project costs. For offshore wind farms located far from shore this may become even more beneficial not only from the wind developer's point-of-view.

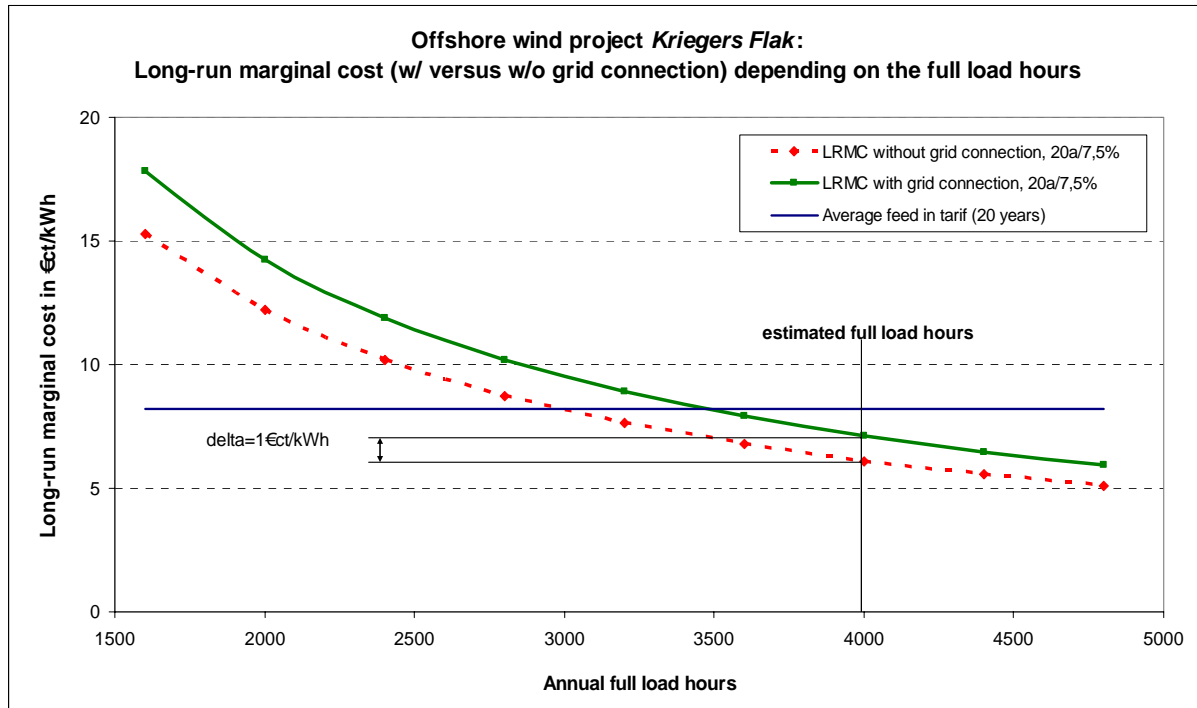


Figure 8: *Kriegers Flak* offshore wind farm – LRMC w/ versus w/o grid connection costs depending on annual full load hours (average feed-in tariff according to the German EEG (2004)).

3.3 Synthesis of RES-E case study results

The choice of the cost allocation principle for RES-E grid integration is a typical energy policy question and highly depends on the implemented RES-E promotion instrument. Following the discussion above it can be concluded that no simple solution exists. Moreover, simple solutions tend to be inefficient. On the other hand, efficient solutions tend to be difficult to implement in practise. This commonplace is also true for the conditions and costs of RES-E grid integration in different EU Member States. Nevertheless, an adequate forward-looking solution should at least take into account the following aspects:

- If the RES-E developer has to cover “shallow” grid connection costs those are a core problem for the wind generation technology.⁷ In case of wind these costs have a high share on the total project investments and may, hence, constitute a significant barrier to invest, see Figure 9. For remaining RES-E generation technologies the costs are in a similar range than for conventional generation technologies. It may thus be a reasonable solution to define a maximal length of the grid connection line that has to be paid by the corresponding generator. This length should be in the typical range of experiences with RES-E grid connection in the past. This would still give probable incentives for RES-E deployment by retaining locational signals leading the interested investor to preferably choose a site near the next grid connection point. With such an approach all other occurring grid-infrastructure related integration costs would be covered by the grid

⁷ Note, that in case of “super-shallow” wind integration (see Figure 1) the wind developer has no problems in this context at all.

operator and would then be socialized via regulated grid tariffs. This, however, is only possible if the different elements of grid integration costs are transparently calculated and an effective regulatory authority is in place.

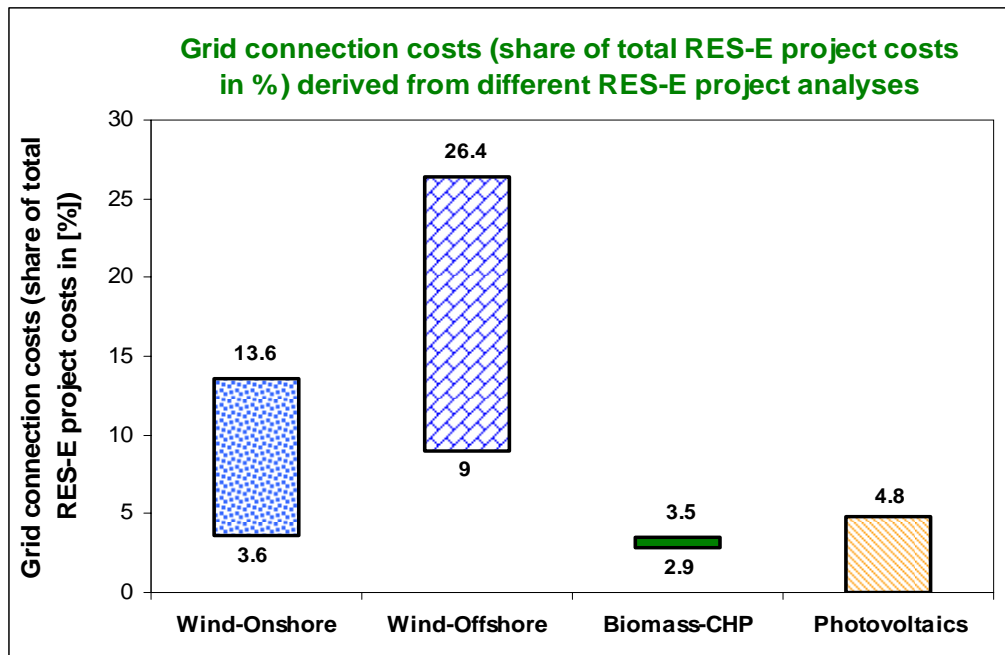


Figure 9: Share of grid connection costs (% of total RES-E investment costs) for different RES-E generation technologies.

- If the RES-E generator has to cover “deep” grid integration costs those can be a problem regardless of any specific RES-E generation technology. Moreover, they can also occur if a conventional generation technology is integrated. As grid reinforcements and upgrades may also serve the needs of other commercial actors in the electricity system (like power trading) they can hardly be individualized. If the electricity market provides locational signals (of the considered countries here in the case study analyses this is the case in the United Kingdom only) then there seems to be no need at all to additionally charge “deep” grid integration costs. However, even if the electricity market provides locational signals the problems regarding the individualization of the occurring costs lead to the solution that it may be more efficient to allocate those costs to the grid operator. The occurring costs would then again be socialized via regulated grid tariffs. Again, this is only possible if the different elements of grid integration costs are transparently calculated and an effective regulatory authority is in place.

4 SYNTHESIS OF SIMULATION RESULTS ON LEAST-COST RES-E GRID INTEGRATION BASED ON THE SOFTWARE TOOL GREENNET

4.1 Scenario settings in GreenNet

In the EU Member States still no common and transparent cost allocation policy for disaggregated RES-E grid integration costs exists. In order to derive recommendations for a harmonized RES-E grid integration approach the major objective of the GreenNet model runs is to investigate the impact of different cost allocation policies on RES-E deployment on EU-25 Member States' level.

The reference scenario in GreenNet refers to the currently implemented cost allocation practice of RES-E grid integration in the EU-25 Member States. The different cost elements are allocated as follows:

- Grid connection costs are treated as part of the total RES-E power plant investments and, therefore, allocated to the RES-E developer.
- For the allocation of grid reinforcement/upgrading costs currently there is no unique practice in the EU-25 Member States. In most of the countries deep RES-E grid integration charging is applied. This means that several costs of RES-E grid integration (incl. grid reinforcement/ upgrading) are allocated to the RES-E developer. Shallow RES-E grid integration charging is applied in Belgium, Denmark, Germany and The Netherlands only (see Table 1 in detail).
- Balancing costs caused by wind generation are treated different in the EU-Member States. In countries using quota obligations for RES-E support (e.g. Belgium, Sweden, UK) balancing costs are usually allocated to the RES-E developer, while in countries with feed-in tariffs RES-E developers usually are not charged for imbalances. Exemptions exist in Spain and The Netherlands (both countries support RES-E technologies based on feed-in tariffs and also charge RES-E developers for imbalances).
- System capacity costs: Given the excess capacities in the conventional European power systems in recent years there has been no shortage on "back-up" capacity caused by increasing intermittent wind integration.⁸ However future projections of conventional power capacities give evidence, that the limited contribution of wind power to system capacity will have to be compensated with "extra" system capacity in the future. These system capacity costs are not likely to be allocated to the RES-E developer. They are rather subject to wholesale power markets and, therefore, will be allocated to end-users.

In the reference scenario of GreenNet several simulation runs are based on the assumption that currently implemented RES-E policy instruments remain unchanged in several EU-Member States up to 2020 (Business as Usual (BAU) RES-E policy). Besides the reference scenario also both extreme scenarios can be modeled, i.e. either the RES-E developer ("deep" charging) or the end-user ("super-shallow" charging) pays several additional costs of RES-E grid integration, see Figure 10.⁹

⁸ However, the model implementation in GreenNet assumes a continuous development of system capacity costs independently of future trends on excess capacity.

⁹ Among the different RES-E technologies a special focus is given to wind generation, both wind-onshore and wind-offshore. Not least due to the fact that wind is mainly located in areas with weak grid conditions (causing additional grid reinforcement/upgrading/extension costs).

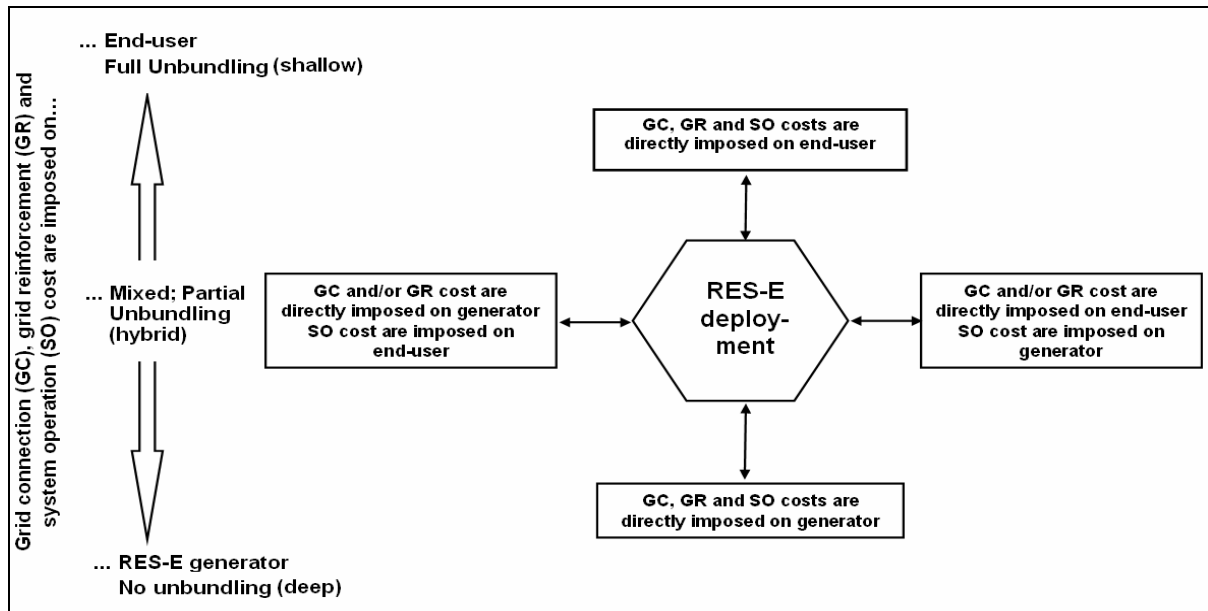


Figure 10: Overview on the bandwidth of possible scenario settings in the model GreenNet

4.2 Discussion of simulation results on RES-E deployment

4.2.1 Reference scenario

According to the reference scenario total RES-E generation within the EU-25 Member States increases from 492 TWh/yr in 2005 to 1028 GWh/yr in 2020. While generation from original RES-E technologies like hydro power and biowaste remains almost stable, especially for wind generation (onshore and offshore), biomass and biogas a considerable increase up to 2020 can be observed (see Figure 11).

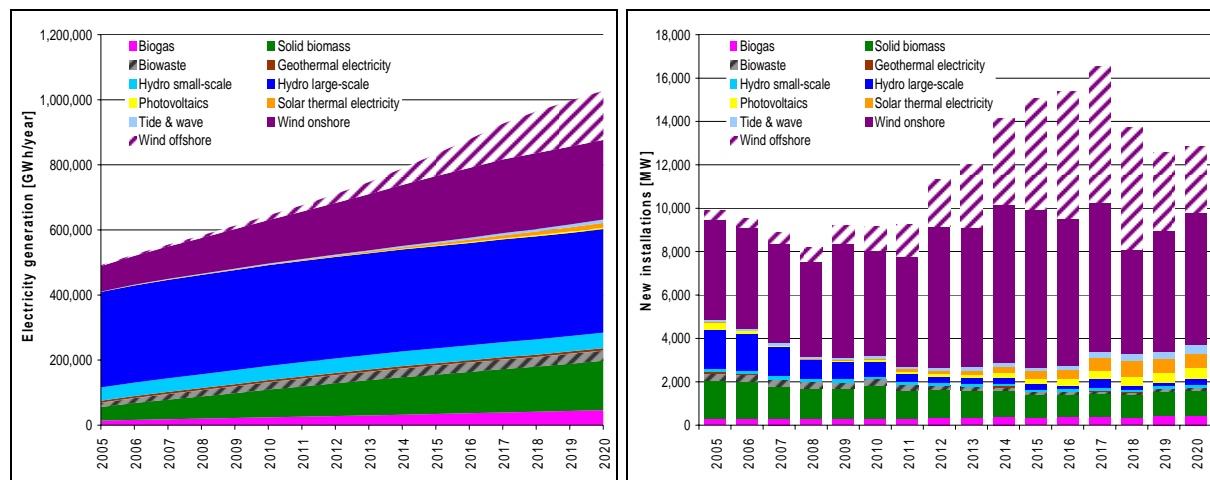


Figure 11: GreenNet reference scenario – RES-E deployment in the EU-25 Member States up to 2020.

4.2.2 “Deep” versus “super-shallow” scenario

While for the “deep” charging scenario several disaggregated cost elements are allocated to the RES-E developer, the “super-shallow” charging scenario indicates a practice where several disaggregated cost elements (including cost for RES-E grid connection) are allocated to the end user.

The cost allocation philosophy of disaggregated cost elements finally affects RES-E deployment. This effect is shown in Figure 12, depicting the development of total RES-E generation for the two extreme scenarios as well as the reference scenario. In relative terms total RES-E generation in 2020 is 4 % higher for the “super-shallow” scenario compared to the reference scenario. On contrary, deep charging leads to a decrease of around 4% of total RES-E generation in 2020.

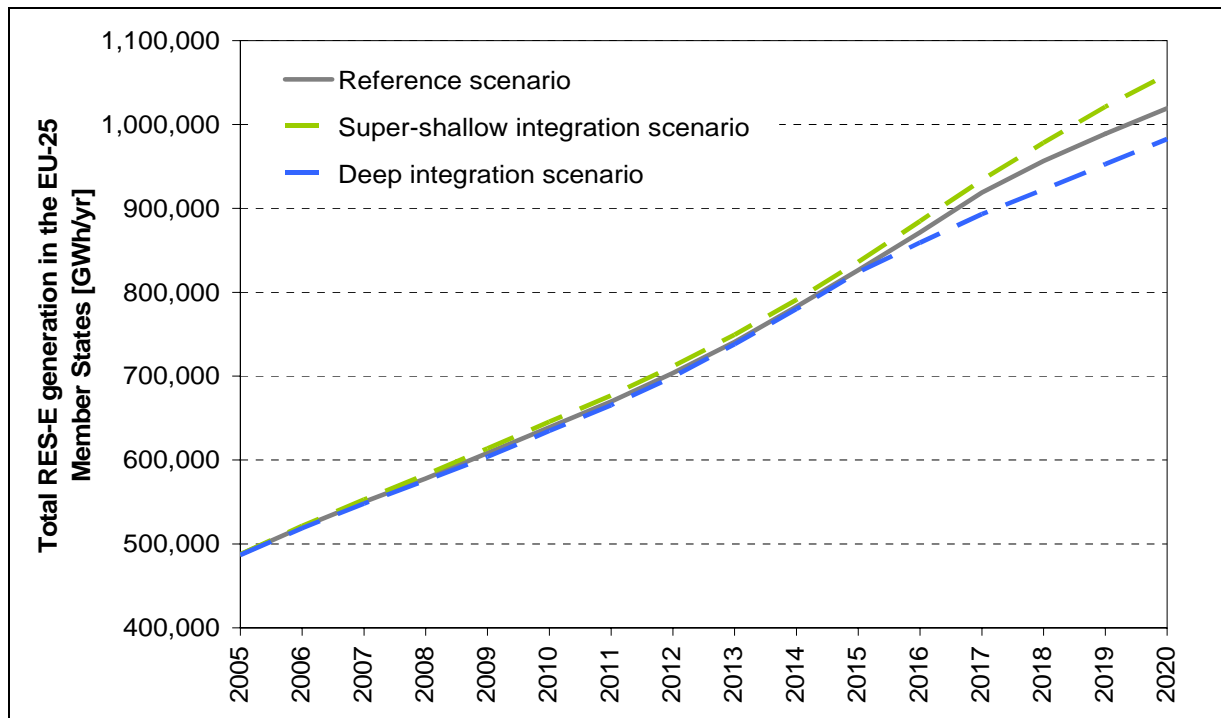


Figure 12: Development of total RES-E generation in the EU-25 Member States for different cost allocation policies of disaggregated cost elements up to 2020. Source: GreenNet

Figure 13 presents the changes of the RES-E generation portfolio in the “super-shallow” and “deep” charging approach compared to the reference scenario up to 2020. Wind-offshore and wind-onshore are the technologies being affected most.

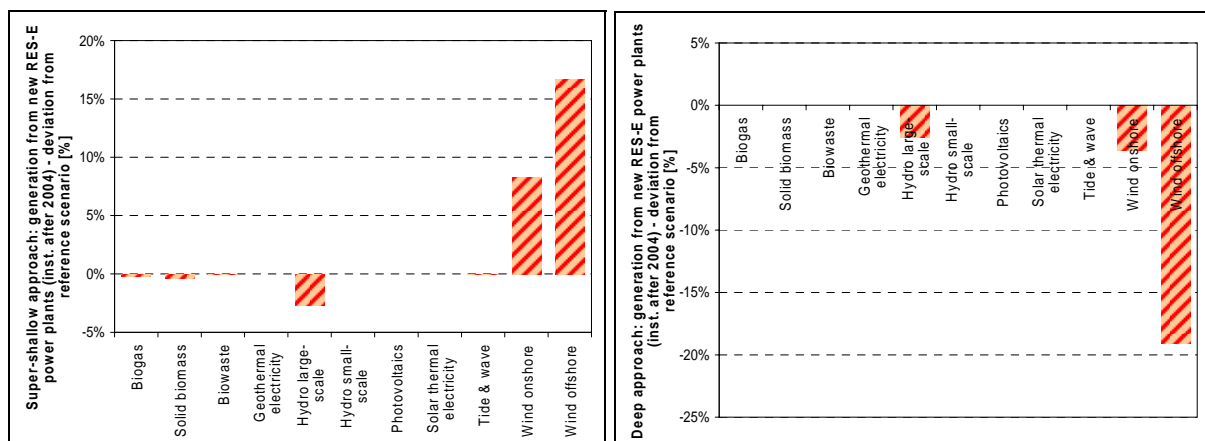


Figure 13: Changes of the RES-E generation portfolio in the “super-shallow” (left) and “deep” (right) charging approach compared to the reference scenario up to 2020. Source: GreenNet

Due to the fact that changes of RES-E deployment in the different cost allocation scenarios are influenced mainly by changes of wind power installations this technology is analyzed in detail. In the reference scenario total wind generation in the EU-25 Member States from plants installed after 2004 is 353 TWh in 2020. In the “super-shallow” scenario the corresponding number is 395 TWh (i.e. plus 12 %) whereas in the “deep” scenario annual generation is 317 TWh (minus 10 % compared to the reference scenario), see Figure 14.

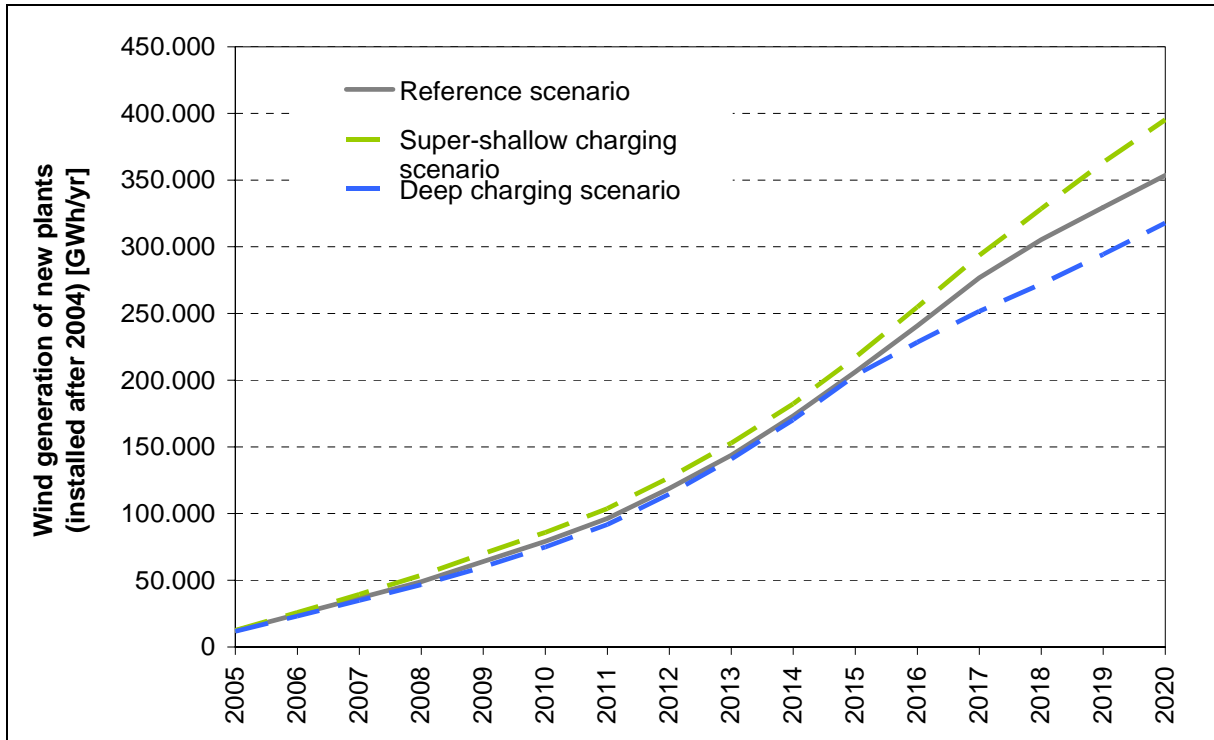


Figure 14: Development of total wind generation in the EU-25 Member States for different cost allocation policies of disaggregated cost elements up to 2020. Source: GreenNet

Figure 15 finally presents the development of the new installations of both wind-onshore and wind-offshore for the different cost allocation scenarios of RES-E grid integration. It can be clearly seen that the highest installations can be expected in the “super-shallow” approach.

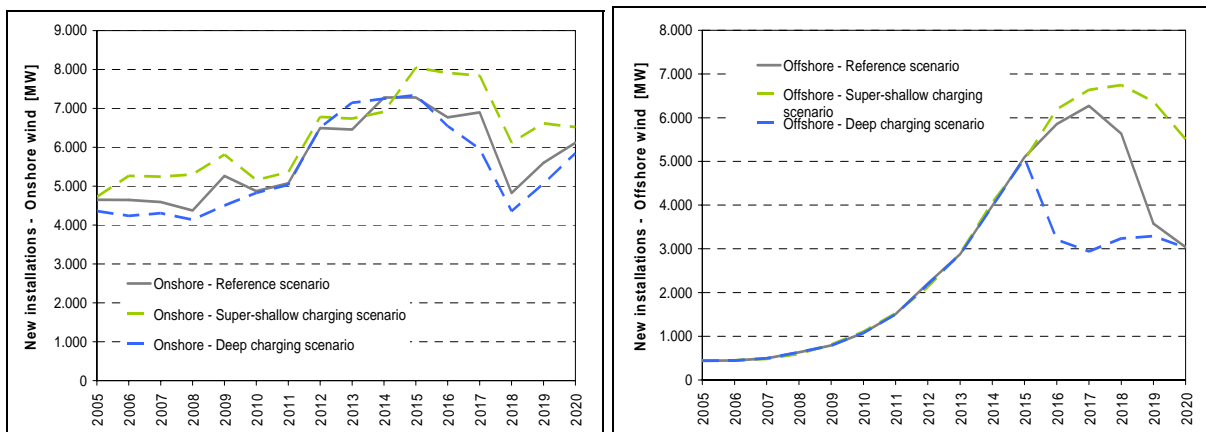


Figure 15: Development of new installed wind-onshore and wind-offshore in the EU-25 Member States for different cost allocation policies of disaggregated cost elements up to 2020. Source: GreenNet

4.3 Synthesis of RES-E simulation results

The effects of the cost allocation practice on RES-E deployment shown in the different simulation runs above have to be interpreted against the background of the currently underlying RES-E support policies in the different EU Member States. A change of the RES-E cost allocation policy is likely to go in line with an adoption of RES-E promotion instrument. Furthermore, it is important to note, that the effects shown above reflect the pure economic (financial) aspects of disaggregated cost allocation in the context of RES-E grid integration only.

According to the results shown in the previous figures wind-onshore and wind-offshore is likely to represent the most dominant RES-E generation technology in the EU-25 Member States up to the year 2020. This trend supports the special emphasis given to grid-related and system-related issues and costs of market integration of wind into the different European electricity systems in the simulation software *GreenNet*. Moreover, the sensitivity analyses carried out with the simulation software *GreenNet* indicate a broad range of system operation costs and grid integration costs of RES-E generation technologies depending on the selected cost allocation scenario settings.

Therefore, for in depth analyses on country level, the individual settings in the simulation software *GreenNet* have to be selected carefully against the country specific conditions implemented in practice.

5 POLICY RECOMMENDATIONS AND CONCLUSIONS

For large-scale RES-E grid integration a clear definition of the boundaries between the RES-E power plant, the grid infrastructure and overall system operation is indispensable. In the past, not least due to small amounts of RES-E penetration the share of extra grid-related and system-related costs has been small compared to the long-run marginal generation costs of the different RES-E power plants. Therefore, these extra costs have not been clarified in detail, but often treated as part of the long-run marginal RES-E generation costs and, subsequently, were allocated to the corresponding RES-E promotion instruments.

But this practise increasingly causes problems with increasing shares of (intermittent) RES-E generation in the different European electricity systems (i.e. mainly UCTE-, Nordel- and UK-system):

- On the one hand, it is obvious that in almost all EU Member States the legal status quo still violates the basic unbundling principles of the corresponding EC Directives as well as economic theory of capital-intensive network industries in general.
- On the other hand, best-practise cases on RES-E grid connection (e.g. offshore wind connection) in countries like Denmark increasingly define the future benchmarks on least-cost RES-E grid integration.

Large-scale RES-E grid integration, furthermore, cannot take place on the expense of other market actors like grid operators. Grid operators increasingly have to compensate negative effects on transmission and distribution networks caused by RES-E power plant location and technology choice. Therefore, it is suggested that explicit mechanisms are created also in grid regulation policies being able to identify and remunerate the increase in investment requirements and possible asset stranding caused by large-scale RES-E grid integration. Then only, the existing economic disincentives for grid operators for absorbing large-scale RES-E generation will disappear. Doing so, it can be argued, furthermore, that the additional investments into the grids also improve security of supply in general and finally – from a system-wide perspective – this may be the overall least-cost approach taking into account also several aspects beyond RES-E grid integration only.

In this context, another central question is whether the same connection boundary should be implemented on the generation-side and on the demand-side. More precisely, on the demand-side the customers have traditionally paid (and still pay) “shallow” grid charges whereas RES-E generators are mainly charged based on a “deep” cost allocation philosophy in the majority of EU Member States. Moreover, an increase in decentralised RES-E generation especially at connections which may export and import electricity at different times, is expected to blur the established distinction between generation and demand connections thus changing the cost drivers for the grid operators. This means that the “deep” charging philosophy may no longer be appropriate.

Recognising this, the implementation of a “shallow” cost allocation and charging approach is supposed to provide even better incentives for grid operators considering network investments facilitating large-scale decentralised RES-E generation. Moreover, if grid connection costs for RES-E generators are included in the grid regulation and grid tariff determination process – and identified to be eligible in the grid operator’s cost benchmarking exercise – the grid operator’s expectation on allowed revenues can be met, see Figure 16.

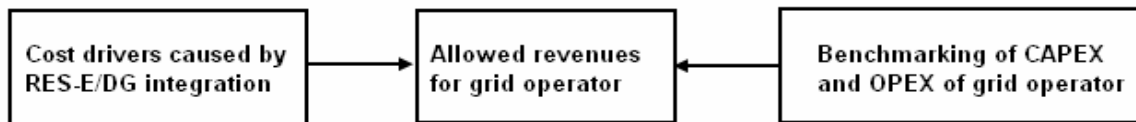


Figure 16: Additional cost drivers for grid operation caused by large-scale RES-E/DG integration

Decentralised RES-E grid integration, furthermore, shall be exposed to locational signals to ensure the efficient choice of location, regardless of the cost allocation and charging policy. The calculation of charges should include both costs and benefits attributed to new locations. In principle, the present value of correct and fully cost reflective “deep” or “shallow” connection charges, that recover the capital expenditures, over the project lifetime, shall be equivalent. Shallow charges might be preferred because they reduce risks and the financing costs of the RES-E generator to be connected.

Last but not least, for acceptance of large amounts of intermittent RES-E (wind) generation in a system, several existing barriers in the wholesale and balancing markets (incl. settlement procedures) have to be overcome. A critical review in this context is also necessary in several EU Member States:

- In the short-term, improved wind forecasting tools are required to reduce the impact of intermittency on system level and, subsequently, system balancing costs.
- In the long-term, however, it is also important to increasingly address demand response options in order to bring extra system balancing requirements and costs towards zero.

Finally, as a consequence of several existing lacks on allocation and reimbursement of grid-related and system-related extra costs in the context of large-scale RES-E grid integration in the EU Member States (RES-E promotion instruments versus grid tariffs versus balancing/wholesale electricity markets) it is recommended to establish a strategic EU-wide policy discussion on unbundling. Moreover, the critical analyses throughout the report shall contribute to the cognition of policy makers that a convergence of different policies –RES-E promotion policy and grid regulation policy – is indispensable. Then only, the ambitious goals of the European Commission on large-scale RES-E grid integration can be met with minimal costs for society.

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