THE RELEVANCE OF UNBUNDLING FOR LARGE-SCALE RES-E GRID INTEGRATION IN EUROPE

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ABSTRACT
Market integration of RES-E generation technologies 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 shortcomings (e.g. ignoring basic unbundling principles) in almost all Member States of the European Union (EU). Therefore, the major objective of this paper is to comprehensively discuss several dimensions of correct unbundling in the context of large-scale RES-E grid integration. Moreover, currently existing demarcation lines between the RES-E power plant, the grid infrastructure and overall system operation are questioned. It is also shown that there exist partly conflicting interests in cost remuneration of different disaggregated cost elements (grid connection costs, grid reinforcement/upgrading costs, extra system operation costs) for different market actors (RES-E developer, grid operator, system operator). It is concluded that only a convergence of different ongoing policies (RES-E promotion policy and grid regulation policy) guarantees the fulfilment of the ambitious goals of the EC on large-scale RES-E grid integration with minimal costs for society.

Keywords: RES-E grid integration; Unbundling; Cost allocation; Grid regulation policy; Europe

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 [11]. 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 (see e.g. [1]):

- 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 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. [25]):

- 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 has to be analysed from the grid operators' point-of-view. At present, in many EU Member States[1] 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 infrastructure planning 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 planning, the grid operator 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.

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 expert discussions on the implementation of new grid regulation models and grid tariff determination procedures just have begun (mainly due to the fact that the installation of a sector-specific energy regulator has been delayed for years).

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 [17]. 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. [1, 23, 8]). On country level corresponding publications exist e.g. for The Netherlands [14], Denmark [4], UK [15], Ireland [22] and Germany [6]. But only a few of them explicitly address separation of RES-E (wind) grid connection and alternative approaches on cost allocation. At present, [9] is 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 paper is to comprehensively discuss several dimensions of correct unbundling in the context of large-scale RES-E grid integration. 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 operators' 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, and system operator).

The paper is organised as follows: section 2 addresses the upcoming challenges of large-scale RES-E grid integration from different points-of-view: the RES-E developer, the grid operator and the system operator. In section 3 the different approaches in grid infrastructure planning and grid regulation are addressed in the context of large-scale RES-E grid integration. Section 4 addresses the value and the additional costs of intermittent RES-E generation. Finally, section 5 derives conclusions on correct unbundling in the context of large-scale RES-E grid integration and, subsequently, correct cost remuneration of different disaggregated cost elements.

2 UNBUNDLING AND 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 [21]. On the 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 operators' 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 operators' 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 grid operators' 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

2. Different grid regulation models (e.g. cost-of-service regulation, revenue-cap regulation, price-cap regulation, yardstick regulation, hybrid 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. [3].

policy[2] 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/updating) caused by policies promoting RES-E generation technologies. This is the so-called "shallow" RES-E grid integration cost approach. In this case, neither the RES-E developer (causing increased investment requirements) nor the grid operator (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]

On the 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. 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 section 3, 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" approach).
- If the grid regulation policy aim is to overcome the grid operators' 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).

2.2 System operation and intermittent RES-E generation

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 section 3, Figures 1a/1b and 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.

Due to intermittency of RES-E generation technologies like wind the system operator has to take care of additional arrangements in system operation for both short-term balancing of generation and load as well as long-term generation adequacy for maintaining system security.

In the introduction of this paper it is already indicated that 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. [25]).[4]

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. [12] and [13]). 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.[5]

3 THE GRID INFRASTRUCTURE

3.1 Natural monopoly character of electricity grids

4. At present, in different EU Member States a variety of different schemes exist for the allocation of corresponding balancing costs.
5. For a comprehensive discussion on the capacity credit of wind generation see section 4 (Figure 6 in particular).

From the economic point-of-view a necessary and sufficient condition for a natural monopoly – like capital intensive electricity grids are – is the so-called *subadditivity* of costs (see e.g. [27]). In the following, the special features of a natural monopoly are illustrated based on the example of offshore wind connection to the existing grid infrastructure. Usually, the following economic situation occurs (see also equation (1)):

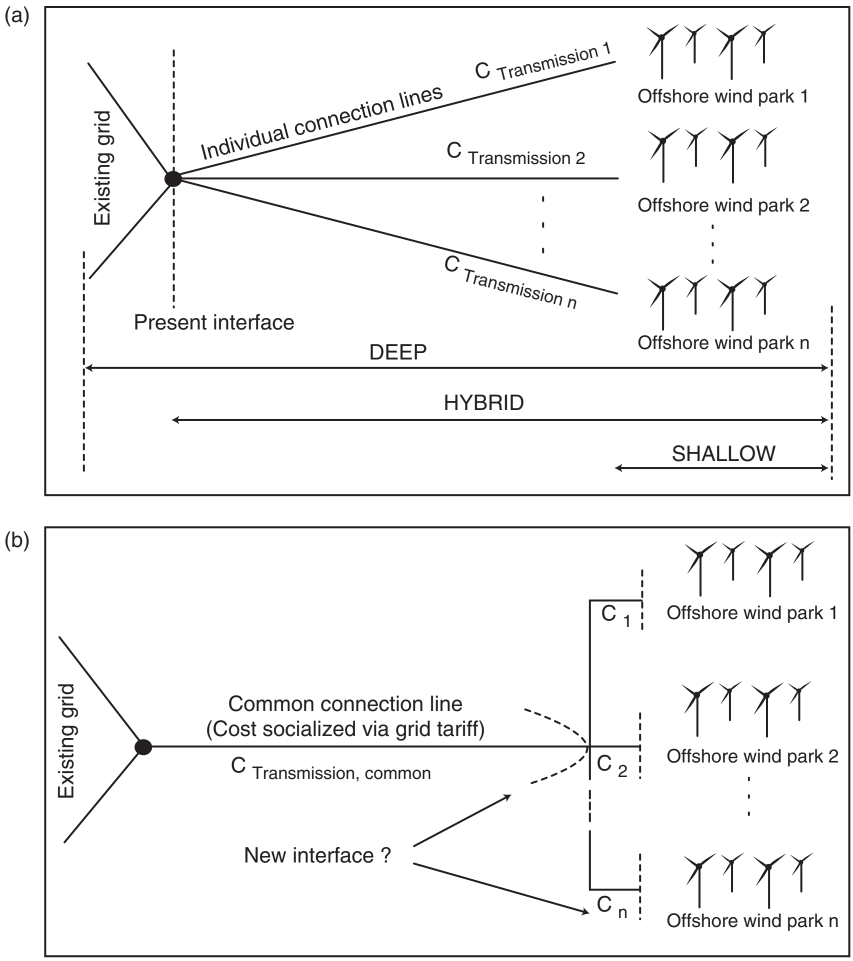

Figure 1: (a) Separate offshore grid connection of each individual wind farm and indication of different demarcation lines ("deep" versus "shallow" versus "hybrid") of integration cost allocation schemes. (b) Common offshore grid connection of several wind farms and definition of possible new interfaces to demarcate wind generation from the grid infrastructure

If $C_{Transmission,i}$ are the offshore transmission grid connection costs of an individual wind farm i in case of separate grid connection (Figure 1a) and $C_{Transmission,common}$ the common offshore transmission grid connection costs of all wind farms (c_i is the individual short distribution grid component of wind farm i) (Figure 1b) the following cost relationship exists:

$$C_{Transmission,common} + \sum_{i=1}^{n} c_i < \sum_{i=1}^{n} C_{Transmission,i} \tag{1}$$

i.e., the cumulated transmission grid connection costs of the individual offshore wind farms (Figure 1a) are higher than the common transmission grid connection costs (plus individual short distribution grid components) of a collective of several wind farms (Figure 1b).

3.2 Status quo of RES-E grid integration policies in Europe

Section 3.1 demonstrates that 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

Table 1: Status quo of different RES-E grid integration cost allocation schemes in the 'old' EU15 Member States ("deep" versus "shallow" versus "hybrid"). Source: [17]

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

6. 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).

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).[6]

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). In countries like Denmark a separation of the grid infrastructure and the RES-E power plant is already implemented (i.e. "shallow" integration cost approach; most transparent case).

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 policies, 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" integration cost approach). On the contrary to the "deep" integration cost approach this guarantees perfect cost transparency and, furthermore, fulfills the basic unbundling principles.

3.3 Allocation of grid-related costs in the context of large-scale RES-E integration

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

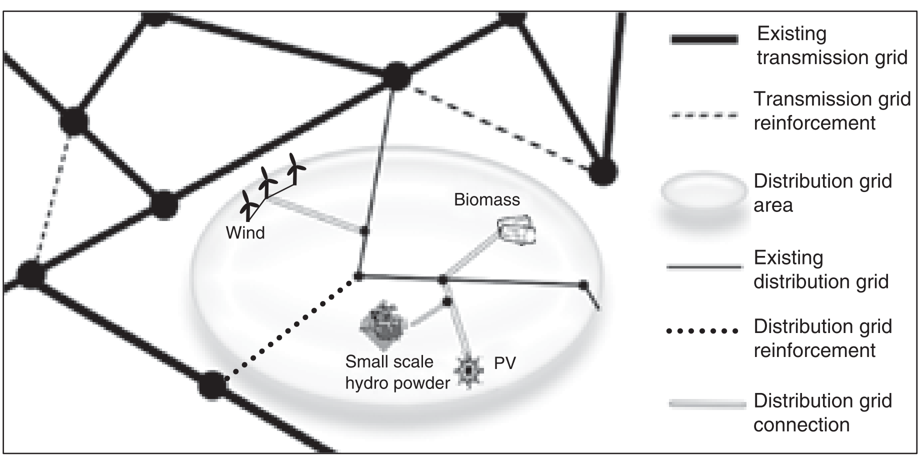

Figure 2: Grid connection and grid reinforcement/upgrading measures on distribution and transmission level caused by large-scale RES-E grid integration

- *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, have a variety of dimensions, as there are e.g. changes in the 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:[7]

- *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. Table 2 and Figure 3 below present the results on the comparison of country-specific transmission grid reinforcement/upgrading costs for different shares of wind penetration in different European countries.

3.4 Challenges for offshore wind grid connection in the future

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 only

7. A standardized calculation method expects the following assumptions: 1. Interest rate: 7.5%. 2. Depreciation of grid infrastructure assets: 40 years. 3. 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. 4. Currency conversion rates: average exchange rates in the year of publication of the study.

Table 2: Country-specific transmission grid reinforcement/upgrading costs for different shares of wind penetration (€/MWh$_{\text{Wind}}$). Source: studies shown in the right column

Empirical data based on country studies														
Transmission grid	Wind generation (share in % of total generation)													
reinforcement cost in /MWh	1.5%	2.6%	4.5%	6.2%	9.4%	12.1%	4.8%	7.2%	19.1%	14.9%	23.6%	6.4%	7.0%	Reference
Belgium I	0.27													van Roy et al [24]
Belgium II		0.29												van Roy et al [24]
France			0.52											Verseille [26]
Germany I				0.14										DENA [6]
Germany II					0.29									DENA [6]
Germany III						0.35								DENA [6]
Poland I							0.18							Janiczek et al [16]
Poland II								0.36						Janiczek et al [16]
Netherlands I									0.56					Hooft [14]
UK I										1.42				ILEX [15]
UK II											1.63			ILEX [15]
Ireland I												0.68		Doherty et al [7]
Ireland II													0.68	Doherty et al [7]

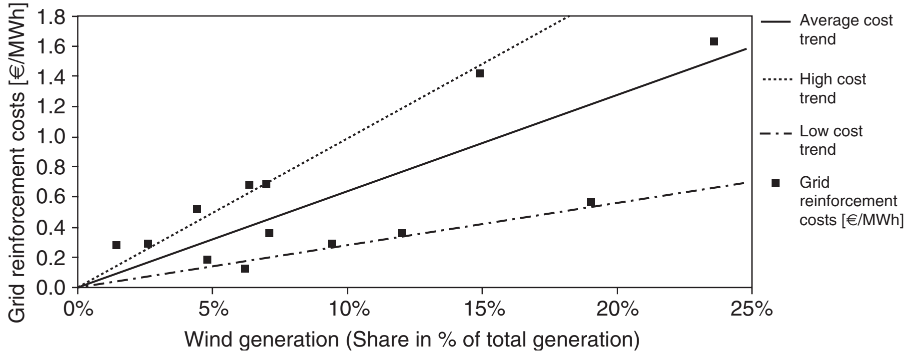

Figure 3: Country specific transmission grid reinforcement/upgrading costs for different shares of wind penetration (in €/MWh$_{Wind}$); different trend lines depending on the strength of the grid and overall wind penetration. Source: see Table 2

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 Nothern Europe, taking into account the economic principles of natural monopolies already discussed in Figure 1b. A common trans-national European offshore transmission grid has to be equipped, furthermore, with offshore

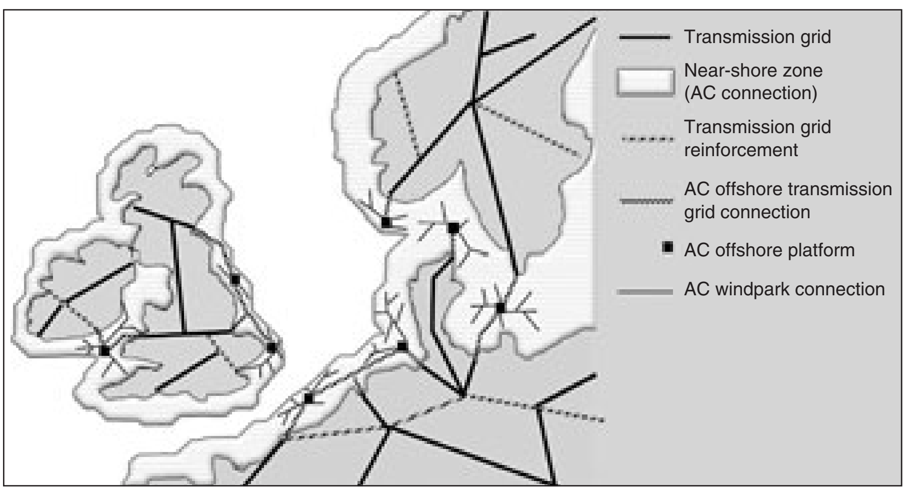

Figure 4: Common trans-national strategy for an offshore extension of the transmission grid in Nothern Europe. Source: [19]

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

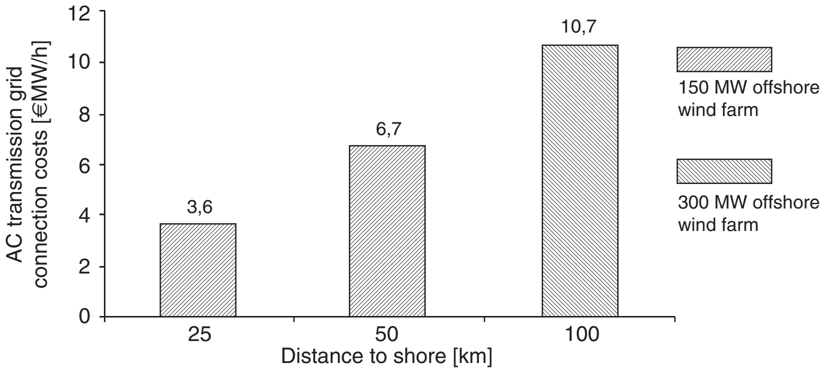

Figure 5: Grid connection costs for different offshore wind farms, depending on wind farm size, distance to shore and corresponding connection technology. Source: [20]

platforms, collecting the individual connection lines of the different offshore wind farms,[8] 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).

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. Empirical data used for calculations in Figure 5 are mainly based on published specific costs of the existing offshore wind farm "Horns Rev" (Denmark) and the planned offshore wind project "Kriegers Flak" (Germany). The indicative grid connection costs for a 150 MW (25 km versus 50 km offshore) and 300 MW (100 km offshore) wind farm are presented in €/MWh_{Wind}, depending on the distance to shore and annual wind generation.[9]

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. [18]). The major purpose of such an Offshore Supergrid™ is to connect several offshore wind farms across geographically separated European sea regions and, doing so, smoothening 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

9. Assumptions: Annual full load hours = 4,000 h/yr. Interest rate = 7.5%. Depreciation period = 40 years.

commercial activities like power trading. For further details in this context it is refered to [18].

4 ECONOMICS OF LARGE-SCALE INTERMITTENT RES-E (WIND) 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. In the short-term, on timescales from less than a second to several hours, a variety of balancing services are necessary in order to maintain stable system operation. In the long-term, intermittent RES-E (wind) generation can provide only limited contributions to guaranteed system capacities (e.g. in the event of peak demand). Therefore, robust approaches are necessary to estimate the additional system-related requirements and costs for stable system operation.

4.1 System operation requirements caused by intermittent wind generation

In general, the driver for short-term system balancing requirements is the magnitude of random power fluctuations, caused by unpredictable changes in both generation and load. Although intermittent wind generation contributes significantly to random power fluctuations, it is not the only source. Currently, in different European countries a variety of different schemes exist for the allocation of corresponding balancing costs (see e.g. [25]).

Long-term analyses estimate the capacity contribution of intermittent wind generation on system level. Although wind power throughout a national network makes some contribution to assured capacity, this contribution is significantly less than that for equivalent conventional generation or non-intermittent RES-E generation. The challenge, therefore, is to determine the contribution of intermittent wind generation to system security. In other words, to determine the amount of conventional capacity that can be displaced by intermittent wind capacity, whilst maintaining the same degree of system security (i.e. without affecting the so-called *"Loss Of Load Probability (LOLP)"*; see e.g. [12])[10].

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10. The *"Loss Of Load Probability (LOLP)"* is the probability that a loss of load event occurs, i.e. that the portfolio of electricity generators in a system cannot meet customer load. As the LOLP-definition does not take into account the possibility of electricity imports from neighbouring systems it is important to note that the loss of load event does not necessarily indicate a black out situation of the power system. One of the core criteria for the LOLP is – besides others – the flexibility and response time of the existing power plant portfolio. E.g., power plant systems with pumped hydro storage plants can accommodate higher wind penetration than generation portfolios consisting solely on sluggish nuclear and/or coal fired plants (see e.g. [12]).

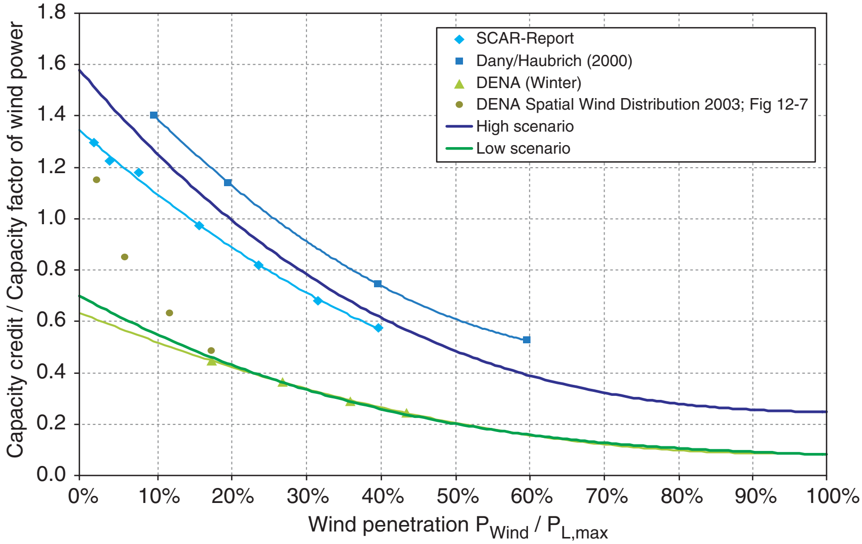

Figure 6: Estimated capacity credit of wind generation depending on wind penetration in the system based on different studies (incl. upper and lower bound scenario). Sources: [15, 5, 6].

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 [10] 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 Figure 6):

- 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.

4.2 Quantifying the extra system capacity costs caused by intermittent wind generation

4.1.1 The 'thermal equivalent approach'

The determination of the capacity credit is a precondition to be able to quantify the extra system capacity costs caused by large-scale wind generation. The calculation of these extra system capacity costs is based on the so-called 'thermal equivalent approach' according to [15]. The description below is partly following this literature text:

The annual wind generation is calculated from the installed capacity in megawatts and the annual full load hours. Then the equivalent amount of conventional capacity required to generate the same annual amount of electricity is determined, assuming a CCGT (Combined Cycle Gas Turbine) at an average load factor. However, conventional capacity can be viewed as delivering two services, energy and capacity.

Assuming, first, that wind generation 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 OCGTs (Open Cycle Gas Turbines). For the cost calculation the capacity requirements are

Table 3: Extra system capacity costs caused by 15 GW wind penetration in UK in 2020 (i.e. around 22% of UK's peak load in 2020). Assumptions: Ratio Onshore: Offshore = 40%: 60%. Source: [2].

Example – Calculation of extra system capacity costs		
Installed wind capacity	**15**	**GW**
Average annual full load hours	**2600**	**h/y**
Total annual wind generation	**39000**	**GWh**
Case I: Without capacity credit		
CCGT load factor	80	%
CCGT full load hours	7008	h/y
Thermal capacity equivalent	5.57	GW
Capacity credit wind	0	%
Capacity contribution wind	0	GW
Required thermal capacity	5.57	GW
Specific cost of thermal equivalent	55	€/kW/y
Capacity cost	306	million €
Extra system capacity cost per MWh Wind	**7.85**	**€/MWh$_{Wind}$**
Case II: With capacity credit		
CCGT load factor	80	%
CCGT full load hours	7008	h/y
Thermal capacity equivalent	5.57	GW
Capacity credit wind	27	%
Capacity contribution wind	4.05	GW
Required thermal capacity	1.52	GW
Specific cost of thermal equivalent	55	€/kW/y
Capacity cost	83	million
Extra system capacity cost per MWh Wind	**2.14**	**€/MWh$_{wind}$**

allocated to new but not leading-edge OCGTs, suitable for peaking operation, based on the consideration that at the margin only OCGTs will be used as any economically feasible existing generation would already be utilised on the system. The annualised capital costs are finally determined depending on annual wind generation.

In the second case, if it is considered that wind generation does contribute to system security, albeit at a smaller rate than conventional capacity, the above capacity requirement is reduced by the level of that contribution. Again, the annualised capacity costs are then derived depending on annual wind generation.

Both cases described above are illustrated with an example in Table 3 (referring to a realistic UK wind deployment scenario in 2020). The bandwidth on extra system capacity costs is between 2.14 €/MWh$_{Wind}$ (default capacity credit according to Figure 6) and 7.85 €/MWh$_{Wind}$ (no capacity credit).

4.1.2 Example: Simulation of extra system capacity costs for Germany up to 2020

The methodology described above is now used to estimate the extra system capacity costs caused by large-scale wind integration in Germany up to the year 2020. It is assumed that up to 2020 around 30 GW of wind capacity is installed in total (15 GW each wind-onshore and wind-offshore). The average annual full load hours are assumed to be around 2,500 hours per year (wind-onshore: <= 2,000 h/yr; wind-offshore: >= 3,000 h/yr).

Table 4 quantifies the extra system capacity costs (i) for the default settings of the capacity credit according to Figure 6, (ii) for pessimistic capacity credit settings (50% of default value) and, finally, (iii) without any capacity credit of wind to the system (column on the extreme right in Table 4). A direct comparison with the recently published results from the German Dena study [6] is not possible, since extra wind-related costs are not presented there on disaggregated level. The guaranteed capacity contribution of wind generation simulated within the Dena study, however, is in the range of the capacity credit in the pessimistic scenario settings in Table 4. The upper limit of the extra system capacity costs for high wind penetrations – assuming virtually no capacity credit – in this model is fixed at 7.85 €/MWh$_{wind}$. Note, that these costs occur in practise as overcapacities in the system are becoming increasingly short.

4.3 Quantifying the extra system balancing costs caused by intermittent wind generation

Up to now, there have been few published analyses on extra system balancing costs caused by large-scale intermittent wind integration. Recent publications mainly address the situation in the UK, Denmark and Germany and in parts of the U.S. Figure 7 summarises the corresponding extra system balancing costs allocated to intermittent wind generation in these countries (for details see e.g. [2]).

When determining the extra system balancing requirements – and corresponding costs – caused by intermittent wind generation in a system the additional deviation compared to a system without wind has to be identified only (but not the total wind forecast error). Finally, the most important aspect in this context is that the resulting forecast error is less than the sum of the individual errors considered.

Table 4: Extra system capacity costs in Germany depending on wind penetration and different settings of the capacity credit of wind generation. Source: [2]

Installed wind capacity	**GW**	**5**	**10**	**15**	**20**	**25**	**30**
Average annual factor	**h/y**	**2500**	**2500**	**2500**	**2500**	**2500**	**2500**
Total annual wind generation	**GWh**	**12500**	**25000**	**37500**	**50000**	**62500**	**75000**
CCGT load factor	%	80	80	80	80	80	80
CCGT full load hours	h/y	7008	7008	7008	7008	7008	7008
Thermal capacity equivalent	GW	1.78	3.57	5.35	7.13	8.92	10.70
Capacity credit wind (default setting)	**%**	**35.2**	**30.6**	**30.6**	**26.5**	**26.5**	**22.9**
Wind capacity contribution	GW	1.76	3.06	4.59	5.31	6.63	6.88
Required thermal capacity	GW	0.02	0.51	0.76	1.83	2.29	3.82
Specific cost of thermal equivalent	€/kW/y	55	55	55	55	55	55
Capacity cost	million €	1.3	27.8	41.8	100.6	125.7	210.1
Extra system capacity cost per MWh Wind	**€/MWh$_{Wind}$**	**0.11**	**1.11**	**1.11**	**2.01**	**2.01**	**2.80**
Capacity credit wind (pessimistic settings)	**%**	**17.6**	**15.3**	**15.3**	**13.3**	**13.3**	**11.5**
Wind capacity contribution	GW	0.88	1.53	2.30	2.65	3.32	3.44
Required thermal capacity	GW	0.90	2.04	3.06	4.48	5.60	7.26
Specific cost of thermal equivalent	€/kW/y	55	55	55	55	55	55
Capacity cost	million €	50	112	168	247	308	399
Extra system capacity cost per MWh Wind	**€/MWh$_{wind}$**	**3.98**	**4.48**	**4.48**	**4.48**	**4.93**	**5.32**

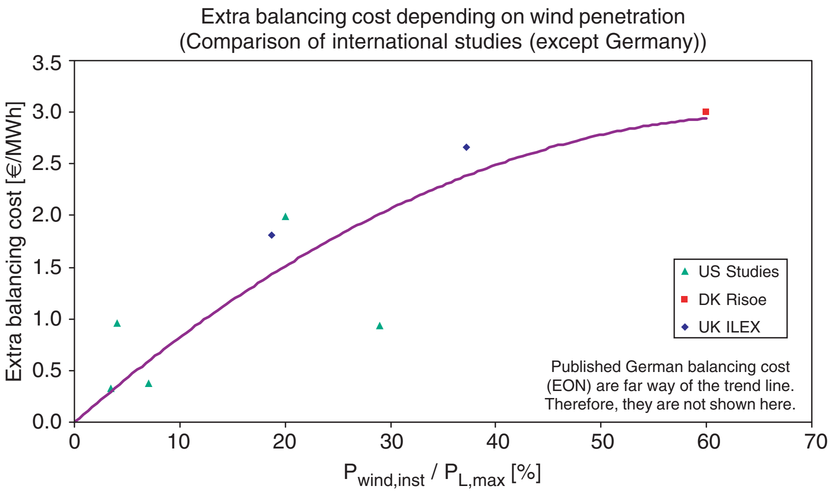

Figure 7: Extra system balancing costs depending on wind penetration in different countries. Source: [2].

5 CONCLUSIONS

For large-scale RES-E grid integration a clear definition of the demarcation lines 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:

- 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 ex-ante 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. In this scenario 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.

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 in this context. Moreover, the critical analyses throughout the paper 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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