Action Plan

Promoting grid-related incentives for large scale RES-E integration into the different European electricity systems

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Preface

In recent years the share of renewable electricity generation has been increasing significantly, especially in Europe. The major reason of this development in the member states of the EU has been the implementation of national promotion policies having been triggered by Directive 2001/77/EC. Looking ahead, this development is expected to be continued and even exceeded: Directive 2009/28/EC on the promotion of renewable energy sources shall provide the legal background for the achievement of binding national targets for the shares of energy from renewable sources in gross final consumption and the reaching of a 20% share of energy from renewable sources by 2020 on EU level.

The use of renewable energy sources for electricity generation will have to contribute significantly to the achievement of this goal: It is expected to need to double from approximately 15% in 2006 to over 30% in 2020 on EU level. This dramatic increase brings about considerable challenges for the secure operation of electricity grids and will necessitate heavy infrastructure investments.

While the promotion of renewable electricity generation is regarded a topic of highest priority and has led to the implementation of respective support mechanisms on national level, corresponding economic incentives for electricity grid reinforcements and extensions have not been equivalently established: While in some cases the financial support for generators is sufficiently high to additionally cover charges for grid related costs, in other cases reluctance of grid operators to connect increasing shares of renewable generation can be observed, when they are not given the opportunity to pass costs of grid and system integration over to their customers via regulated tariffs. For the reason that incremental costs for grid upgrades and extensions can hardly be determined on a transparent basis but may constitute a severe financial barrier in the development of renewable energy installations (e.g. offshore wind), it is seen as a necessary precondition for reaching ambitious deployment goals, that regulatory mechanisms for grid operators include favourable rules for the reimbursement of dedicated infrastructure investments.

Within the project Green*Net*-Incentives the topic of providing a favourable economic environment for grid operators to be able to fully commit to the European renewable energy policy has been extensively discussed with relevant stakeholders.

The Green*Net*-Europe simulation software, that allows the quantification of different cost components related to the integration of electricity from renewable energy sources into the European electricity grids, has been updated and extended. Also, most recent modelling results are explored in this report.

Based on the analysis of different grid regulation mechanisms and the interpretation of modelling results, policy recommendations are derived on how to motivate grid operators to actively support the development of renewable electricity generation in Europe at minimal costs for society.

Lukas Weißensteiner
Hans Auer

Table of Contents

1 Introduction

1.1 Motivation

Deployment of electricity production from renewable sources (RES-E) in recent years has mainly been driven by energy policy. In this context, economic support in the form of promotion schemes provided the basis for large scale installations of RES-E plants. Yet, it could be observed, that even though the level of financial support could be regarded sufficiently high for the exploitation of existing renewable potentials, actual deployment of generation capacities discontinued at a certain level or even did not take place from the start in the case of several European countries:

Non-technical barriers to a sustained development are to an important extent connected to the access to the electricity grid infrastructure. It is a crucial feature of this barrier that its removal is not linked to the timely constraint of removing technical bottlenecks but that it constitutes an immanent and inert characteristic depending on the economic environment designed by regulation. As a result, electricity grid operators, both on distribution as well as on transmission level, have been and still are being accused of delaying and obstructing permits for the connection of RES-E plants to the grid.

It has been the intention within the project Green*Net* -Incentives to adopt the perspective of grid operators in order to detect existing economic barriers for RES-E grid integration and to identify suitable regulatory principles, which incorporate incentives for grid operators to commit to investments dedicated to the integration and further deployment of RES-E.

In a broader context, the dilemma of grid operators being reluctant towards investments dedicated to the integration of RES-E has to be regarded as a dilemma of non-consistent energy policy: While renewable promotion schemes are targeted at providing sufficient financial incentives for installing and operating RES-E plants, additional costs other than in the generation sector, namely for grid and system integration, are in many cases not accordingly being reflected in policy instruments[1].

As a matter of fact, implemented mechanisms of regulating monopolistic grid operators make it necessary for these market actors to avoid any investments, which cannot be passed over to their clients. Incentive regulation schemes have been introduced in many European countries replacing rate-of-return (cost of service) regulation. These mechanisms[2] reward grid operators for cutting their costs below anticipated trajectories and at the same time penalize them for incurring additional costs – as for the integration of RES-E – if no according adjustments are undertaken.

In the course of the project Green*Net* -Incentives an analysis of currently implemented regulatory mechanisms in 10 European countries, a consultation of key stakeholders in RES-E integration (grid operators, (regulatory) authorities, project developers) and a variety of events on expert level resulted, among other outcomes, in one common conclusion: The economic framework for grid operators needs to be designed in a way, that investments and increased operational costs due to the integration of large scale electricity generation from renewable sources can be reimbursed at reasonable conditions.

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[1] Support levels received by generators, which are sufficiently high to compensate grid operators directly for all grid related costs, can for various reasons be regarded as inefficient, i. e. lead to higher transfer costs for society (higher producer surplus from public support, higher rate of return of entrepreneurs), see section 4.2 of this report. Due to uncertain future generation capacities to be connected in a certain region, DSOs are reluctant to take the risk of over-sizing capacity when expanding the grid and hence of being unable to recover respective – in specific terms excessive – costs. Doing so, on the other hand, sufficiently large increments of extensions may not be realised. Actual grid enhancements may therefore in a dynamic context be not cost efficient. Information asymmetry, asymmetric bargaining power and potential hold-up may add to this situation.

[2] A distinction between different types of incentive regulation mechanisms can be found in the "Report on economic incentives for grid operators in grid regulation" in the download section of www.greennet-europe.org

Above this, the authors recommend, that clear and detailed rules for the separation of responsibilities (including financial responsibilities) between grid operators and generators with respect to the connection of RES-E installations to the grid, the necessary reinforcement of the existing grid and system operation shall be defined on a European level in order to implement best practice mechanisms from the start in all Member States. Not only can efficiency criteria be met in such a case but also the framework for internal competition between developers improved.

1.2 Outline of the action plan

The action plan is organised as follows:

- Section 2 shortly outlines expert discussion platforms organised within the project. The key issues addressed in the discussions are summarised.
- In section 3 approach and major results of the stakeholder consultation are presented.
- Section 4 discusses the regulatory environment for the integration of increasing shares of electricity from renewable sources into the grid infrastructure and suggests the implementation of economic incentives for grid operators into the regulatory mechanisms with this respect.
- Section 5 is dedicated to the modelling work performed in the project. After a description of the Green*Net*-Europe model including approach, key assumptions and major features selected simulation results are presented for two RES-E deployment scenarios on EU Member States level.
- Finally, section 6 derives tailored recommendations for cost efficient grid integration of RES-E for all relevant stakeholder groups.

2 Expert discussion platforms

2.1 Experts' views on RES-E grid integration in different European regions

The objective of setting up 5 expert discussion platforms has been to bring together market actors and stakeholders in order to identify best practises and criteria of large scale RES-E integration against the background of observed barriers and gained experiences.

Each of the five expert discussion platforms has been organised as two-day events taking place in different European regions. These individual expert discussion platforms concentrated on several main topics with regard to the European region in question. Main topics included:

- RES-E grid integration in different European system configurations and individual countries
- System stability issues in the context of variable RES-E generation and intelligent grid management
- Regulatory issues
- Case studies on different successful RES-E projects

Primarily addressed stakeholders and participants comprised transmission system operators, distribution system operators, regulatory authorities, utilities and RES-E investors/plant operators. With the mentioned variety of presenting and participating stakeholder groups, a broad range of recommendations and experiences on practices and criteria for RES-E integration has been obtained. The actual assessment of the current situation of the development of RES-E projects, indentified necessary steps to improve this situation and further conclusions may reflect the diverging viewpoints of stakeholders. For this reason, the contributions to 5 expert platforms provide a welcome insight into ongoing discussions.

Above this, the "non-institutional" approach of organising these expert discussion platforms within a European project has been utilised by different stakeholder groups for informal discussions of proposals how to overcome identified potential shortcomings.

In order to summarize the individual conclusions derived, one wrap-up presentation has been compiled and published on the website www.greennet-europe.org for each expert discussion platform.

2.2 Expert discussion platforms in detail

Power system stability and wind power integration in the Nordel system

11 – 12 October 2007 in Oslo, Norway; organised and invited by Sintef

- Views of the Norwegian system operator on challenges due to large scale wind power
- System and market integration of wind power
- Power system stability and large scale wind power
- Voltage control and reactive power compensation
- Panel debate: Best practice – grid codes and standardization

Wind energy integration in Germany and Europe

18 – 19 October 2007 in Stuttgart, Germany; organised and invited by
EnBW Energie Baden-Württemberg and by the
Institute of Energy Economics and the Rational Use of Energy, Universität Stuttgart

- Wind power integration studies
- Forecasting, reserves and refinement
- Grid aspects
- Promotion of RES
- Wind energy management in practice
- Future integration options of wind energy

RES-E grid integration in Poland

8 – 9 April 2008 in Gdansk, Poland; organised and invited by
Poszanowanie Energii i Środowiska (SAPE Polska) and Baltic Energy Conservation Agency (BAPE)

- RES-E grid connection regulation in Poland, Czech Republic, United Kingdom and Austria
- Possibilities of large scale wind power grid connection in Poland
- Available sources of co-financing for RES-E projects in Poland

Technical and regulatory aspects of network integration of RES in Romania

21 – 22 April 2008 in Bucharest, Romania; organised and invited by
Autoritatea Natională de Reglementara în domeniul Energiei (ANRE) and by
Centrul pentru Promovarea Energiei Curate şi Eficiente în România (ENERO)

- Legal framework of network connection – the Romanian experience
- Romanian green certificates market
- Wind farm connection to distribution networks
- Implementation of the Romanian strategy in the field of RES – actual state of art and perspectives
- RES potentials in Romania

Integration of large-scale RES projects to the electricity system – Experience and perspectives for Greece

6 – 7 May 2008 in Athens, Greece; organised and invited by the
Regulatory Authority for Energy of the Hellenic Republic (RAE)

- Integration of large-scale RES projects into the electricity system
- RES projects and the electricity system – the Greek context
- Analyses of the operation of the Greek electricity system and stability and dynamic studies under high wind penetration conditions
- Special issues of island systems

All related material of these expert discussion platforms – like the agenda, presentations and wrap-up presentations – is available for download at the **Green*Net*-Incentives** project website: **www.greennet-europe.org**

3 Consulting the opinion of stakeholders on non-technical barriers of RES-E integration

3.1 Objective of the stakeholder consultation

There are several groups of stakeholders in the electricity market with different views and opinions on barriers and information deficits related to large-scale RES-E grid integration. These can be divided into three key groups: Energy regulatory authorities, distribution grid operators and RES-E developers. Their priorities related to grid connection and operation of distributed RES-E sources significantly differ (in fact, sometimes are exactly opposite) and could be summarized as below:

- **Energy regulatory authorities**: Protection of the final consumer, regulation of costs of grid operation and enhancements and support of RES development (in some countries).
- **Distribution grid operators**: Operate the grid safely, economically, without technical complications and additional costs for themselves.
- **RES-E developers**: Get the RES-E source connected to the grid – quickly, without administrative and technical barriers, without additional costs and fees for grid connection and benefit from available support systems for RES-E.

All three stakeholder groups were focused on and consulted in 10 European countries through 72 personal or telephone/e-mail interviews using specific questionnaires developed in order to reflect priorities and issues relevant to each stakeholder group involved. The aim of the stakeholder consultation has been to identify several existing non-technological barriers and information deficits on large-scale RES-E grid integration, issues related to grid connection of RES, priorities of the relevant stakeholder group, evaluation of current grid connection practices and system of support of RES.

3.2 Results of the stakeholder consultation

Two examples of results of the evaluation of stakeholder responses are presented below:

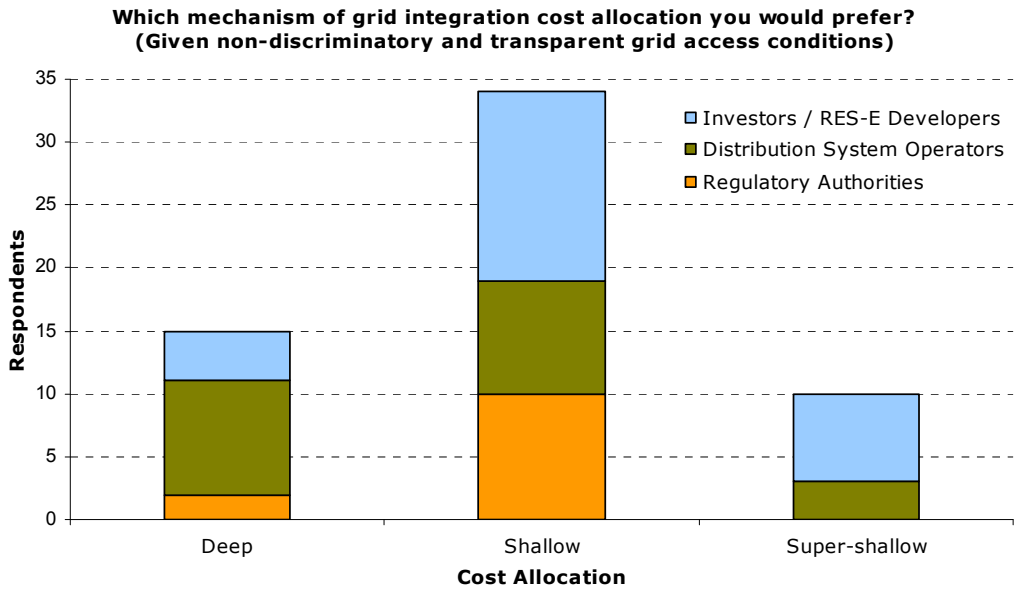


Figure 3.1: Preferred grid integration cost allocation mechanism by stakeholder group; all stakeholders, all countries; 59 respondents.

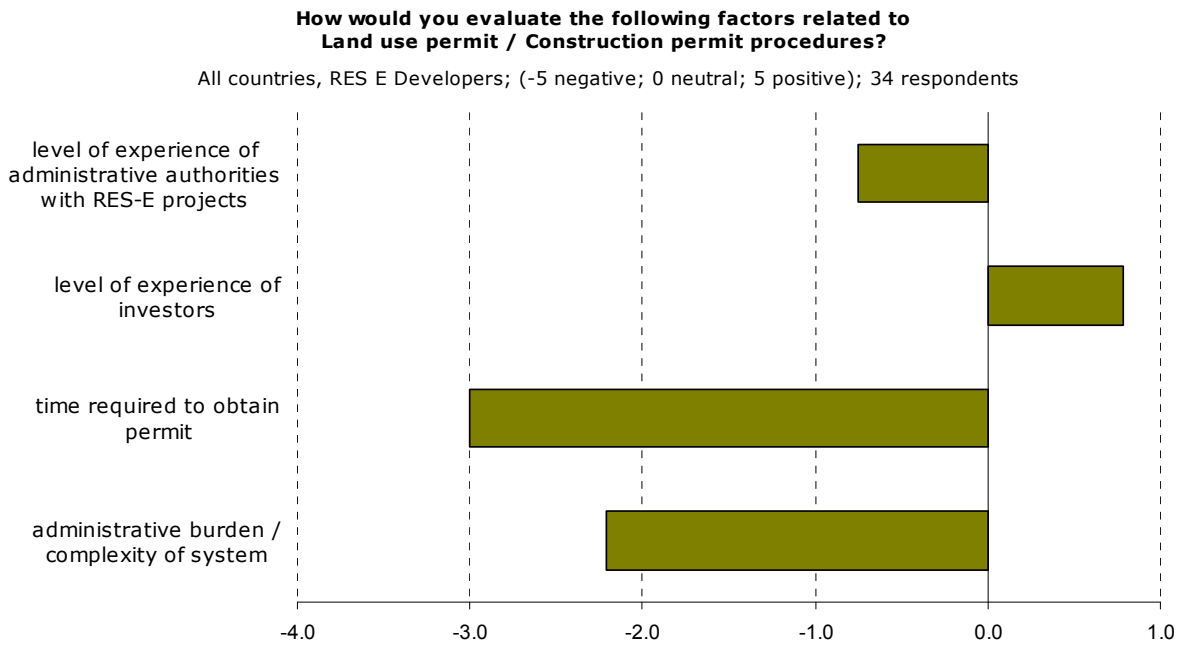


Figure 3.2: RES-E developers' evaluation of land use / construction permit procedures related to RES-E installations; all countries, 34 respondents

The key results of stakeholder consultation could be summarized as below:

3.2.1 Key non-technological barriers for grid connection of RES-E sources

The support schemes for RES-E in some countries are not sufficient and sometimes create additional barriers. Such barriers which could become important risk factors for RES-E developers and project financiers are:

- **Low level of support for some technologies in technology specific RES-E support systems**, and
- **Absence of long-term guarantees for the stability of support**.

The key non technological barriers related to RES-E project development are:

- **Administrative procedures related to the development of RES-E projects**, and
- **Lack of coordination between authorities** involved in administrative procedures related to RES-E projects.

Other important barriers that were identified are of socio-economic nature, namely:

- **Little public acceptance of RES-E installations** in some countries, and
- **Activities of various interest groups directed against RES-E development**. These groups could be environmentalists, local NGOs (NIMBYists), fossil/nuclear lobbyists etc..

Further conclusions by individual topic resulting from the stakeholder consultation are summarized in the following sections.

3.2.2 Potentials and current situation of RES-E generation

- In general, considering responses from all stakeholders and all countries, onshore wind energy is perceived and evaluated as RES-E source with highest and most important potentials, followed by a group of RES-E sources with very small difference - biomass, small hydro and solar PV. Tidal/Wave (where relevant), geothermal electricity and solar thermal electricity generation were evaluated as RES-E sources with the least significant potential by all stakeholder groups – this corresponds with the current share and status of technological development of these technologies in the sample countries.
- Regulators are significantly more conservative regarding their expectations. Regulators estimate small hydro as the source with the most beneficial potentials.
- DSOs ranked the potential of offshore wind highest.
- According to RES-E developers, onshore wind is considered as the most promising RES-E source.

3.2.3 Current dynamics of development of RES-E

- In general, considering responses from all stakeholders and all countries, solar PV and onshore wind are considered as the most dynamically developing RES-E sources. Biomass, biogas and small hydro are slightly behind with similar levels of development.

3.2.4 Motivation provided by RES-E support systems

- All countries that were covered in the stakeholder consultation apply in some form support systems for RES-E production. The most common system of support is a feed-in tariff; fewer countries have implemented a quota system with tradable green certificates. The exception is Norway, where investment subsidies and tax benefits for the support of RES are used.
- There were no significant issues related to RES-E support mentioned in the interviews and in the questionnaires that would create or contribute to the creation of non-technological barriers with respect to grid access for RES-E generators.
- Regulators see support systems as more motivating compared to other stakeholder groups. Support systems are regarded as most motivating for onshore wind, small hydro and biogas according to regulators. On the other hand, regulators regard the support for offshore wind energy a non sufficient motivation.
- The point of view of DSOs is more or less balanced, compared to regulators and RES-E developers; they do not have extreme opinions. From their point of view, the support systems are the most motivating for solar PV and slightly less motivating for biomass and onshore wind.
- From the point of view of RES-E developers, the support systems are the most motivating for solar PV and biomass and slightly less motivating for onshore wind, small hydro and biogas. RES-E developers evaluate the support/motivation for onshore wind energy as low, although still positive.
- In particular, long-term guarantee of support (for feed-in tariffs or premiums) is a very important motivating factor, sometimes with even higher importance than actual levels of feed-in tariffs / premiums.
- The level of long-term guarantee of support is significantly more positively evaluated by regulators, while DSOs and RES-E developers with experience from real life projects are less positive and optimistic.

- The long-term guarantee of support is very positively evaluated in Germany, Greece and the Czech Republic. All three countries apply transparent RES-E support systems with long-term guaranteed feed-in tariffs.
- According to several responses, Hungary, Austria and Slovenia would need improvement of the currently applied feed-in tariff systems as regards long-term guarantee of conditions of support. An improvement of the current quota-based system would be needed in the UK (a feed-in tariff system for small scale applications has been under preparation at the time of research) and a paradigm change in the Norwegian support system is demanded by respondents.

3.2.5 Priority grid access

- According to the results of the stakeholder consultation, the legally guaranteed access to the grid for RES-E sources and priority transmission and distribution is not considered as a key barrier in countries where this guarantee is currently not applied.
- Introduction of positive discrimination of RES-E as regards the guarantee of grid access or transmission and distribution of RES-E, however, may become an additional motivating factor for RES-E grid integration.

3.2.6 Administrative barriers

- **Lengthy, unclear and complicated procedures (spatial planning / construction / EIA) and lack of coordination between authorities involved in administrative procedures related to RES-E projects are mentioned as the key barriers for the development of new RES-E projects almost unanimously by all stakeholders.**
- Regulatory authorities as well as DSOs have very similar views on these administrative permit procedures. Regulators are slightly more critical than DSOs.
- The key problems according to regulators and DSOs are spatial planning, construction permits and EIA (environmental impact assessment) procedures as well as lacking coordination between authorities. On the other hand, licensing and grid connection procedures are not considered as a barrier.
- Regulators and DSOs tend to evaluate administrative obstacles in a less critical way than RES-E developers, who have the most critical point of view.
- The administrative procedures related to developing RES-E projects have been evaluated by regulators and DSOs as a strongly negative factor (or barrier) in all covered countries except the UK, Czech Republic, Norway and Romania, where the results of evaluation are neutral or slightly positive. Especially in Greece, Hungary and Italy, the complexity of the support system and the related administrative burden are evaluated as very serious barriers.
- Regarding planning / construction permit procedures evaluated by RES-E developers:
  - Particularly the time required to obtain permit(s) and the complexity of the system resulting in administrative burdens were considered as most serious barriers to RES-E project development. The level of experience of relevant administrative authorities with RES-E projects was evaluated negatively as well.
  - On the other hand, RES-E developers consider their level of experience with planning permit / construction permit procedures as sufficient, so this factor is not considered as a barrier.

- As regards EIA procedures evaluated by RES-E developers:
  - Lacking experience of administrative authorities or RES-E developers with EIA-procedures is not considered as a barrier.
  - On the other hand, time required passing through EIA procedures, the complexity of the system (resulting in administrative burden to RES-E developers) and strict requirements for nature / landscape protection are considered as serious barriers to RES-E project development.
- As regards grid connection procedures evaluated by RES-E developers:
  - Experience of DSOs as well as RES-E developers are not considered as a problem and do not constitute a barrier.
  - Similarly as in the case of other administrative procedures, time requirements to get connected to the grid and the complexity of the system (resulting in an administrative burden to RES-E developers) are considered as serious barriers.
  - Reluctance of DSOs in the process of grid connection and overall cooperation with project developers are considered as the second most serious barrier (after time requirements).
  - In addition, the way of cost coverage for connections and strict technical requirements for grid connection create an environment, which is not supportive to quick and simple connection of RES-E projects to the grid.
- Lack of coordination between authorities as viewed by the stakeholders clearly shows the need for improvement. This means simplification of administrative procedures related to development, grid connection and operation of RES-E plants.
- Centralised administration of all procedures necessary for development, grid connection and operation of RES-E projects is an option, which could improve the situation and would be accepted by a major part of RES-E developers.
- Most of the other factors influencing the development of RES-E projects, which have been evaluated, do have a positive influence on the development of projects. The key supporting factors are:
  - Activity of interest groups supporting RES-E (associations, NGOs, RES lobbyists)
  - Interest of equity investors and banks to invest into or finance RES-E projects
  - Public acceptance of RES-E installations
  - Setting of indicative targets for RES-E
- There are also factors that are considered to be neutral or slightly hampering the process of development of RES-E projects – namely competition in acquisition of suitable sites.
- One factor, which has been clearly identified as a barrier to the development of RES-E projects, is the activity of various interest groups directed against RES-E development. These groups could be environmentalists, NGOs (NIMBYists), fossil/nuclear lobbyists etc.
- Surprisingly, the public acceptance of RES-E sources was evaluated as rather high, although direct decisions of local / regional authorities, (which often interpret the opinions and will of their electorate – the citizens) or indirect influence on administrative procedures are in many cases non-supportive and slow down the process of RES-E project development in some of the countries involved.

3.2.7 Grid connection regulation for RES-E

In most of the countries covered by the stakeholder consultation systems with shallow allocation of grid connection costs[3] (or hybrid systems) are in place. Only in Norway and Austria, systems with deep allocation of grid connection costs have been reported to be in effect.

The three stakeholder groups also differ in their views on the preferred system of grid connection cost allocation and the opinion within one group is non-uniform, even within one stakeholder group in one given country. Nevertheless, it could be concluded that:

- Most of RES-E developers support shallow or super-shallow approaches;
- DSOs tend to support shallow systems but are often not consistent in their opinions;
- Regulators mostly support shallow systems;
- In general, a majority of stakeholders prefers shallow systems of grid connection cost allocation.

The transparency of allocation of costs of grid connection to single installations was evaluated as sufficient and non-discriminatory by approximately 75% of respondents.

The transparency is not considered sufficient mainly by RES-E developers, in particular in Austria, the Czech Republic and Italy. The rules for charging / allocating costs are considered discriminatory in some way mainly by RES-E developers, in particular in Austria, the Czech Republic, Romania and Italy.

According to the results of questionnaires, locational signals for siting RES-E plants are implemented in some way in Austria, Norway, Slovenia and Greece.

Implementation of locational signals would be preferred by 70% of DSOs included in the stakeholder consultation as it would improve planning of grid extensions.

According to the results of the stakeholder consultation, almost 90% of DSOs as well as RES-E developers confirmed that information about grid infrastructure is available fully or partly. There were only individual negative responses that are not uniform with replies of other stakeholders from the same country and the respective stakeholder group. These negative responses may, however, indicate some problems with availability of information about grid infrastructure in Italy and Romania.

A full report summarizing results of the stakeholder consultation on different non-technological barriers and information deficits on large-scale RES-E grid integration conducted in 10 European countries as well as a summary presentation are available online in the download section of the **Green*Net*-Incentives** project website: **www.greennet-europe.org**

[3] compare section 4.2.2

4 Economic incentives for grid operators for the integration of RES-E

4.1 Introduction

Operation of electricity grids constitutes a natural monopoly. In order to prevent
a) monopolistic price determination, which would lead to welfare losses, and
b) potential discriminating behaviour,
this segment of the electricity value chain is subject to regulation.

Hence (national) regulatory authorities have developed mechanisms to derive a tariff structure for the provision of services as grid access, metering, electricity transmission and distribution, which sets a limit to grid operators' profits.

Core elements of according regulatory mechanisms are the provisions concerning the accountability of (new) investments (for cost-based approaches as well as for incentive-schemes in terms of a "starting point"): Regulatory authorities try to identify a necessary stock of assets as basis for the calculation of a respective return on equity. Infrastructure investments may alter this acknowledged stock corresponding to predefined rules; these may or may not be "passed through" into higher tariffs.

Therefore, regulatory mechanisms in general and especially the treatment of investment costs strongly impact the deployment of RES-E and the success of respective national support schemes, as respective grid and system integration is generally connected with upfront costs for the grid operator in terms of expenses for grid connection and grid reinforcement.

Only if grid operators are incentivised by predefined mechanisms for the integration of RES-E generation, they are enabled to actively support the national and international energy policies for the deployment of renewable energy sources by providing the necessary upgrades of the electricity grid infrastructure.

4.2 The grid connection/access boundary question

4.2.1 The role of unbundling

When integrating significant amounts of RES-E generation technologies into the existing electricity systems, the question, where to define the boundary of (financial) responsibilities between project developers (power generators) and grid operators with respect to grid connection/access is still one of the most controversial issues in practise. Moreover, besides the connection of RES-E facilities to the existing grid infrastructure also grid reinforcement and extension measures caused by large-scale RES-E system integration raise a set of new questions, e.g. whom to allocate corresponding extra costs to and how to socialise them. In any case, in an intermeshed grid infrastructure the allocation of grid reinforcement and extension measures and corresponding costs to a marginal RES-E generation facility is ambiguous,[4] see Figure 4.1.

[4] Not least due to the fact that several other market participants (especially power traders) also benefit in their business segments from additional transmission capacities.

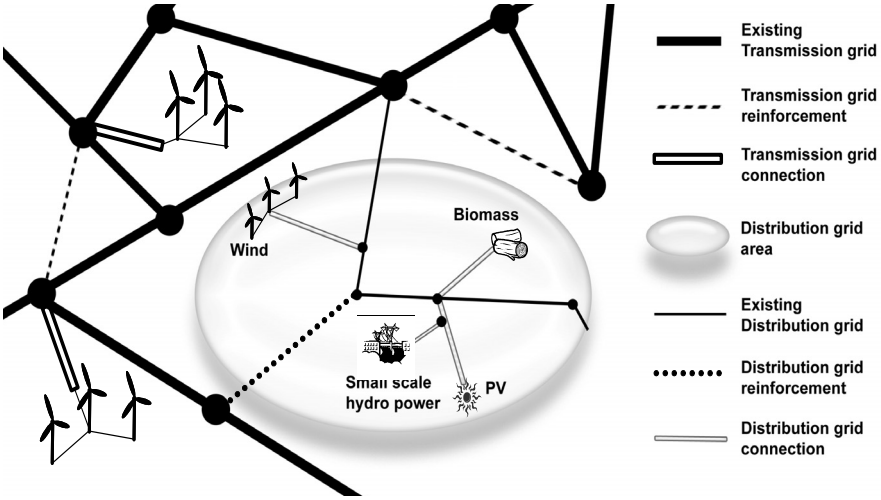


Figure 4.1: Grid connections and grid reinforcements caused by large-scale RES-E integration (Auer (2006)).

The core problem in this context is that any changes in an intermeshed grid infrastructure (e.g. also disconnection of a large industrial customer) will alter the load flows in an electricity system. Therefore, the status quo of load flows in an electricity system represents just a snapshot of the existing randomization of generation and load centres. Moreover, the status quo as well as changes of load flows incorporate a variety of dimensions, as there are e.g. changes in the geographic distribution of generation and load centres, bottlenecks in peaking periods or commercial power trading activities. In consideration of these interactions, the allocation of load flow changes and, subsequently, grid reinforcement and extension measures to the integration of a single new RES-E generation facility appears questionable.

4.2.2 Different grid connection boundaries for RES-E generation facilities

Textbooks on the economic theory of monopolies (e.g. Averch/Johnson (1962), Baumol/Bradford (1970), Baumol et al (1983), etc.) would expect to allocate both RES-E grid connection costs and grid reinforcement and extension costs to the grid infrastructure and to socialize these costs through the transmission and distribution tariffs[5] (and not to include either of these two cost components to the total RES-E project costs). In practice, however, several grid-related cost components (at least grid connection costs) are still allocated to the long-run marginal generation costs of power generation, especially as far as RES-E grid connections to the distribution grid are concerned. In general, the following grid connection boundaries between the RES-E generation facilities and the grid infrastructure are possible (see Figure 4.2, Figure 4.3, Figure 4.4 in detail):

- "Deep" Integration: Based on this approach, costs for grid connection as well as grid reinforcement/extension are allocated to the RES-E developer and add to overall long run marginal costs of RES-E generation.
- "Shallow" Integration: Applying a shallow grid integration approach, the RES-E developer bears the grid connection costs, whereas grid reinforcement/extension costs are attributed to the grid operator (and eventually are being socialised via grid tariffs).
- "Super-Shallow" Integration: Following this approach, costs resulting from grid connection and reinforcement/ extension are allocated to grid operators (and socialised via grid tariffs).

[5] In principle, there exist both options: (i) socialisation within the supply area of a grid operator or (ii) socialisation across the whole country/market/region.

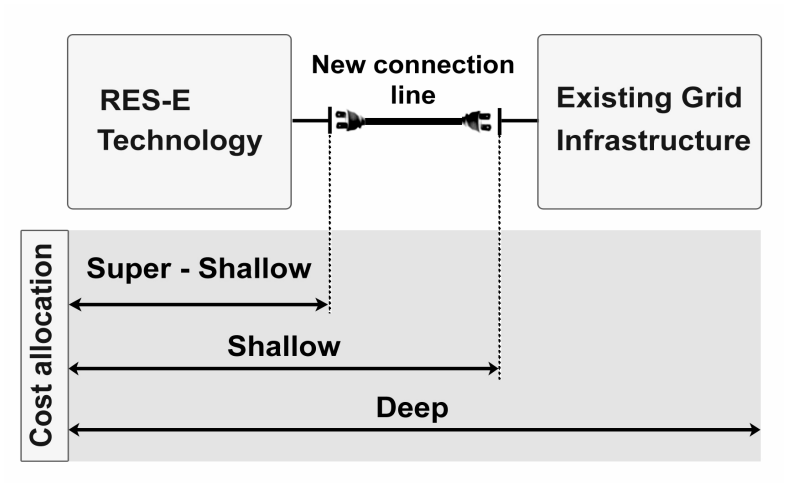


Figure 4.2: Different connection boundaries between the RES-E power plant and grid infra-structure. Source: Auer et al (2006).

In practise, however, there mainly exist hybrid approaches incorporating elements of both "deep" and "shallow" RES-E grid integration. This means in particular that usually parts of grid reinforcement and grid extension costs are allocated to the newly connected RES-E generation facility (i.e. some kind of "deep" grid integration fee) and remaining parts of deep costs are socialised in the grid tariffs. In addition, the entire grid connection costs are borne by the RES-E developer and allocated to the long-run marginal generation costs in the hybrid model. Table 5.3 represents a list of currently implemented cost allocation mechanisms in the Member States of the European Union.

In some EU Member States the existing pattern for allocating RES-E grid integration costs might change in the near future, not least due to the currently ongoing benchmarking and grid regulation implementations by national regulatory bodies. Although these regulatory procedures are driven to fulfil the basic unbundling principles of the different EC-Directives and the implementation of cost transparency in grid infrastructure charging rather than by RES-E grid integration policies, finally the existing boundaries between the RES-E power plant and the grid infrastructure may be shifted increasingly towards the RES-E generation facilities, resulting at least in a "shallow" integration policy or even beyond.[6]

The "super-shallow" RES-E grid integration policy finally fulfils almost all expectations of the theoretical considerations in economic theory (with respect to monopoly regulation). However, the accompanying implementation of locational signals is a precondition for maintaining economic efficiency and an important dimension for a sustainable and cost minimizing integration of RES-E generation facilities into existing electricity systems, especially when considering small generation units in distribution grids and the deployment of remote sources.

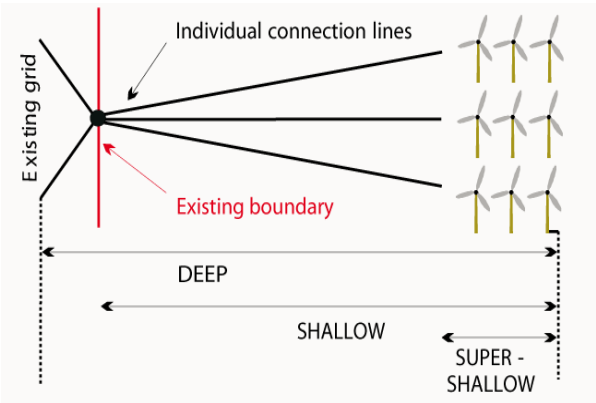
[6] Interestingly, in the past the demand side always has been treated differently (compared to generation) when defining the grid connection boundary of customers. According to economic theory there is no obvious reason to do so (see e.g. Jamasb et al (2005)). Demand customers traditionally have paid "shallow" connection charges – for assets specifically required for their connection – whilst distributed generators have been charged on a "deep" basis, i.e. the full costs arising from the connection including the costs of replacing equipment associated with protecting the network or also the provision of ancillary services. However, an increase in RES-E grid integration in the future, especially at connections which may export and import electricity at different times, is expected to blur the established distinction between demand and generation connections thus fundamentally changing distribution grid operators' cost drivers. These new circumstances also lead to the conclusion that existing charging structures for RES-E grid integration (still mainly "deep" and "hybrid" models) may no longer be appropriate.

Therefore, the "super-shallow" grid integration policy option has been developed in recent years mainly for large-scale offshore-wind (but also onshore-wind) integration into the exiting transmission grids rather than for integrating remaining RES-E generation technologies on distribution grid level. Moreover, when considering large-scale offshore wind integration into transmission grids, usually the economic situation presented in equation 1 exists:

If $C_{Transmission,i}$ are the offshore transmission grid connection costs of an individual wind farm *i* in case of separate grid connection (Figure 4.3 (left)) and $C_{Transmission,common}$ the common offshore transmission grid connection costs of all wind farms (c_i is the individual inter-array grid component of wind farm *i*; see Figure 4.4 (right)) the following relationship exists:

$$C_{Transmission,common} + \sum_{i=1}^{n} c_i < \sum_{i=1}^{n} C_{Transmission,i} \qquad \text{(Equation 1)}$$

Equation 1 demonstrates that cumulated transmission grid connection costs of the individual offshore wind farms (Figure 4.3 (left)) are higher than the common transmission grid connection costs (plus individual inter-array grid components) of a collective of several offshore wind farms (Figure 4.4 (right)). For a comparative analysis of strictly individual versus cost efficient joint connections of UK Round 2 offshore find farms see Econnect (2005).



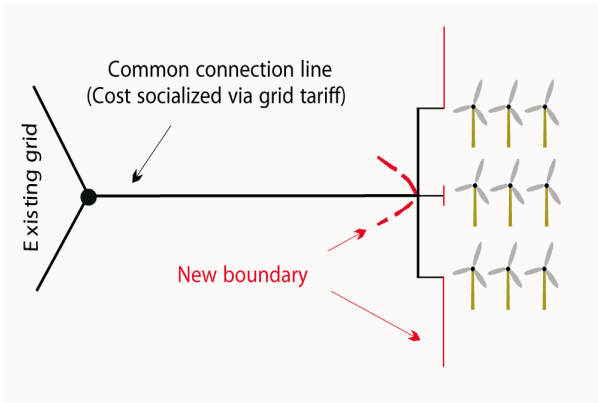


Figure 4.3: (left). Separate offshore grid connection of each individual offshore wind farm and indication of different boundaries for different integration policies. Source: Auer (2007).

Figure 4.4: (right). Common offshore grid connection of several offshore wind farms and shift of new connection boundaries towards offshore wind farms. Source: Auer (2007).

4.2.3 The locational signal aspect in the context of RES-E integration

The overall objective of different cost allocation and RES-E integration charging policies is to guide efficient expansion and use of the electricity grids (distribution grids in particular), on the one hand, and efficient management of the assets connected to the grid infrastructure representing both generation and load facilities, on the other hand. Whereas economic theory presents clear approaches and procedures for optimal RES-E grid integration into existing electricity systems,[7] circumstances in practise are far more complex and accompanied by a variety of uncertainties, imperfections and problems. A selection of these critical issues of the different RES-E integration policies in practise is discussed in subsequent paragraphs.

[7] In economic theory, the general principle underlying efficient RES-E grid integration charging is that charges should reflect the different marginal costs and benefits to the electricity system at each node of RES-E connection.

1. "Deep" Integration: Ideal versus Real World

In general, the deep RES-E integration approach has the advantage of providing strong locational signals for new entrants. However, this approach – having been traditionally adopted by distribution grid operators in the past – is far from uncritical. In practise there exist at least the following challenges (see also Jamasb et al (2005), DTI (2006), Auer (2006), Vogel (2008), Barth et al (2008)):

- Although deep RES-E integration is characterised by favourable locational signals to new entrants, the computation of proper deep connection costs (and, subsequently, connection charges to RES-E generators) is very difficult because it is impossible to correctly foresee the future number of generators, the demanded connection capacity and choice of locations[8]. Therefore, a best guess has to be made when calculating location-specific deep connection charges, trading-off the benefits of larger increments against the risk of over-sizing connection capacity and hence prescribing excessive charges for the connection of RES-E generators.
- Furthermore, assuming the case that the connection assets of a specific location are shared by more than one RES-E generator, the costs would also be shared, but as the assets would be quasi-public goods, efficient charges would not necessarily be the same for several new entrants at the same location if their willingness to pay is different.
- In almost all cases the situation described above is getting even more complex taking into account dynamics: RES-E connection applications are rather sequential in time than simultaneous. For sequential connection inquiries the first mover problem at a specific location is inherent, i.e. the critical question arises whether or not the first entrant shall be charged the full costs and encourage subsequent entrants to rebate some fraction (either by granting the right to the first entrant to charge successors, or calculating a charge for successors by the grid operator and rebating it to the first entrant).[9]

- Last but not least, there exists a strong concern about the deterrent effects on large-scale RES-E deployment in case of deep integration charging policies. Moreover, this approach violates the basic unbundling principle and, therefore, also undermines the legal framework of the Directives of the European Commission trying to implement a common internal European electricity market.

2. "Shallow" Integration: Ideal versus Real World

Although deep RES-E integration policies provide strong locational signals, recognition of the disadvantages of this approach has favoured rather hybrid mechanism (incorporating elements of both deep and shallow charging) in the majority of EU Member States in recent years (see Table 5.3 in detail). Moreover, not least driven by the expectations to fulfil the basic unbundling principles of the EC-Directives further amendments towards shallow integration policies are expected in the context of RES-E grid integration in the near future.

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[8] Only in theory the grid operator can optimally plan the electricity grid and specify the location of each new entrant by setting corresponding location-specific and entrant-specific deep connection charges. In this ideal world the total collected connection charges from each entrant at each location would exactly add up to the total connection costs of several new RES-E generators.

[9] In general, RES-E generators and, therefore, also the first entrant are likely to be less well-informed than the grid operator about the connection capacity needed and corresponding costs. Moreover, the first entrant usually is not in a financial position to raise the capital to pay for more than its own grid connection. Therefore, from the first mover's point-of-view it is an advantage if grid operators charge for the cost of the connection in proportion to the use made of the different entrants. However, in this ideal case the grid operator faces the following risks: (i) subsequent entrants must arrive as predicted, (ii) the correct connection capacities must be chosen and (iii) the willingness to pay for connection of subsequent entrants must be similar.

Shallow RES-E integration policies aim to limit the connection assets attributed to the generator (e.g. up to the next voltage level). However, if it is to signal locational preferences for RES-E integration into the existing grid efficiently, then a shallow integration charge has to incorporate also location specific cost elements. Otherwise a conflict of interests will arise between a generator wishing to connect a remote power plant – utilising favourable sources – to the closest point of the existing grid infrastructure on the one hand and the respective grid operator favouring a connection point, at which total network costs are minimised, on the other hand. This could lead the grid operator to delaying or obstructing connection in certain grid areas, which are regarded not to be cost-minimising. The rejection of a RES-E connection inquiry can therefore be regarded as an extreme variant of setting locational signals in the shallow integration approach.

Compared to the deep integration approach, shallow integration charging has at least the following further advantages (see also Jamasb et al (2005), DTI (2006), Auer (2006), Vogel (2008), Barth et al (2008), Weissensteiner (2009)):

- Shallow RES-E integration costs and corresponding charges are presumably easier to define than those for the deep integration approach.
- The first mover problem disappears since the first entrant is expected to be charged only costs of the connection in proportion to the use made of it. Moreover, from the grid operator's point-of-view the risk of non recoverable costs, which cannot be recovered from generators, in case of over-sizing connection capacity (e.g. for providing the basis for synergies for later RES-E connections at the same location) disappears since grid reinforcement and upgrading costs are socialised in the grid tariffs and, therefore, are directly borne by the network users.
- Previous arguments lead to the conclusion that barriers for entry are low in case of shallow integration policies, providing favourable framework conditions for large-scale RES-E deployment. Moreover, shallow RES-E integration is supposed to be more transparent for stakeholders concerned.
- Costs of capital are likely to be higher for RES-E developers than for regulated grid operators.[10] With this respect, shallow integration policies can lead to lower overall integration costs: cost components for grid reinforcements and upgrades – being allocated to the grid operator and socialised in the grid tariffs of the network users in case of shallow integration – are not included in the financing costs of the RES-E installation to be connected. This provides a strong argument against deep integration charging.
- In case of diverging integration costs, which are positively correlated with pure long run electricity production costs, (super)-shallow charging bears the potential to lower the producer surplus. For this reason, overall transfer costs for consumers for the support of RES-E can be lowered, or the volume of supported production increased under a constant support volume. Again, the implementation of location signals is necessary to maintain overall economic efficiency.
- Finally, the shallow RES-E integration approach goes more in line with the unbundling principles of the EC-Directives than the deep approach. Moreover, due to clear separation of the assets of RES-E generation facilities on the one hand and the grid infrastructure on the other hand extra grid infrastructure costs (grid reinforcements, upgrades and extensions) caused by large-scale RES-E integration can be better incorporated into "forward-looking" grid regulation models where an extra term can be foreseen to socialise these extra costs.[11]

[10] Mainly due to higher risk premiums and shorter depreciation periods the financing costs are likely to be higher for RES-E developers than for regulated grid operators. For example, RES-E generation facilities are depreciated in time horizons of 10-15 years whereas regulated grid operators depreciate their grid infrastructure assets in 40-50 years.

[11] Forward-looking grid regulation models incorporating also extra grid-infrastructure related costs caused by large-scale RES-E integration are comprehensively discussed in subsequent sections.

4.3 The problem of asset stranding for grid operators

4.3.1 Overview of cost drivers for grid operators due to RES-E integration

The previous section has comprehensively analyzed the different cost allocation and RES-E grid integration policies mainly from the RES-E developer's point-of-view. However, when considering large-scale RES-E integration also the grid operator is confronted with much more financial risk as recognized up to now (for details see e.g. Auer (2007)):

- On the one hand, currently implemented grid regulation models apply a strong downward pressure on distribution grid operator's costs and, subsequently, also distribution grid tariffs. At present, this regulatory environment adversely affects any investment initiatives into the electricity grid infrastructure, not only those foreseen to provide a level playing field for large-scale RES-E integration and other innovations like so-called "smart grid" concepts. The basic principles of currently implemented grid regulation procedures and the corresponding interactions with RES-E grid and system integration are briefly summarized and critically discussed in section 4.3.2 below.
- On the other hand, electricity grids are capital-intensive infrastructure elements being characterized by grid assets' life-times over many decades. Therefore, long-term investments into the grid infrastructure expect stable regulatory conditions. Moreover, once investments are made they are effectively sunk and, therefore, grid assets are vulnerable to changes in regulatory conditions which could prevent or hinder cost recovery. Therefore, grid operators are extremely reluctant to commit to infrastructure investments, which enable large-scale integration of RES-E generation facilities into their grids, unless the corresponding extra costs are being recognized, quantified and – most importantly – cost recovery is guaranteed based on innovative, forward-looking grid regulation models.

Figure 4.5 below presents the two categories of cost pressure forces, regulated grid operators have to cope with at present: (i) cost cutting incentives according to the currently implemented incentive regulation models (left); (ii) a variety of currently unconsidered extra cost drivers in case of large-scale RES-E grid and system integration (right).

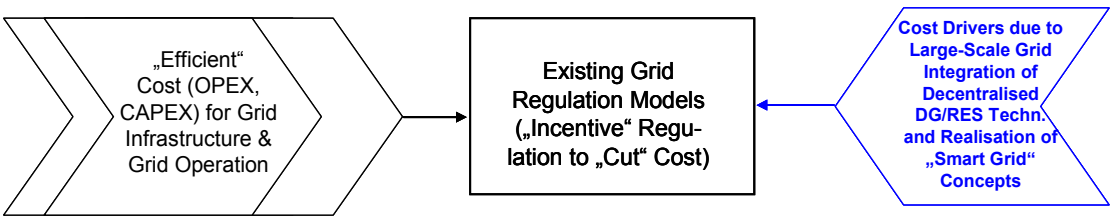

Figure 4.5: Problem of asset stranding in existing grid regulation models due to unconsidered cost drivers caused by large-scale RES-E integration. Source: Auer (2006).

4.3.2 Cost drivers due to incentive regulation

The overall objective of incentive regulation models, which have been implemented in many EU Member States in recent years, is to provide the regulated electricity grid operators with incentives to improve their investment and operating efficiency (taking into consideration also exogenous and structural constraints) and to ensure that network users benefit from these efficiency improvements. In order to do so, a couple of individual steps are necessary in practise, see Figure 4.6.

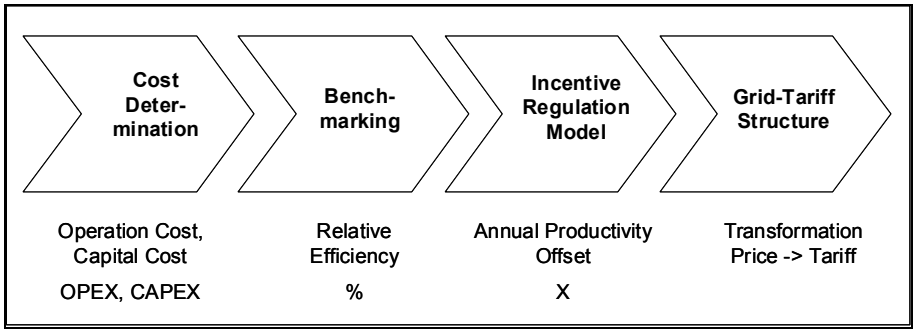

Figure 4.6: Overview of the different steps of a grid regulation process.

The different steps of a grid regulation process in practise can be summarized as follows:

- Step 1: The determination of the actual cost structure and the different cost categories of a firm (mainly capital and operation costs) is a precondition in the grid regulation process in order to be able to compare the status quo of a regulated firm with predefined exogenous and endogenous benchmarks.
- Step 2: The cost-benchmarking exercise itself is the most controversial part of the grid regulation process in practise. In recent years, regulators have adopted and applied a variety of benchmarking methods and techniques to better capture also the unique characteristics of electricity grids. However, there still exists a controversial discussion on the applicability of several of these benchmarking methods whether or not they are able to describe the complexity of reality sufficiently. Moreover, the description of the economic performance of a grid operator by a single efficiency parameter is denoted hazardous anyway.
- Step 3: In the next step, the benchmarking result – i.e. the relative efficiency of the investigated firm compared to remaining firms in the sample – is implemented into the "RPI-X" approach of one of the incentive regulation models. There exist different philosophies to implement the productivity offset X (i.e. the efficiency improvement factor in the upcoming regulatory period) into the incentive regulation models.
- Step 4: Finally, authorized (aggregated) price levels have to be transformed into different grid tariffs for different customer groups. In practise, there exists some degree of freedom in the design of the different grid tariffs and tariff structures for grid operators.

4.4 Cost drivers due to large-scale RES-E grid integration

Grid operators are forced to be "cost efficient" based on these regulatory circumstances and are reluctant towards investment in general, regardless whether or not any RES-E integration activities are concerned. In case of investments due to large-scale RES-E integration the economic situation for electricity grid operators becomes even more unfavourable, since additional cost drivers have to be taken into account (on distribution grid level):

Selected examples of currently unconsidered extra cost drivers on distribution grid level caused by large-scale RES-E integration are as follows:[12]

- Completely new design criteria and operational concepts are necessary due to bidirectional load flows in case of significant amounts of RES-E generation.
- Significant reinforcements, upgrades and extensions of existing network infrastructure elements (overhead lines, cables, transformers, switching devices, etc.) are necessary.
- Higher technical standards and new concepts for ancillary service provision like voltage and frequency regulation, accounting and billing (devices and procedures) are necessary.
- The installation of new information and communication technologies (ICT) is necessary to to manage active and intelligent distribution grids.
- Higher transaction costs have to be taken into account to operate actively managed distribution grids due to the increasing number of market actors.

Due to the fact that above mentioned extra costs for distribution grid operators in case of RES-E integration are not explicitly taken into consideration in the existing grid regulation models – but cost recovery is essential for capital intensive infrastructure investments being effectively sunk once the investment is made – the risk of asset stranding for grid operators is high. Therefore, based on the existing regulatory environment, grid operators might not be able to integrate RES-E projects on large-scale on the basis of a financial risk evaluation.

The basic "RPI-X" incentive regulation formula is as follows:

$$P_t = P_{t-1} * (1 + RPI - X) \qquad \text{(Equation 2)}$$

where

P_t.....authorized price-cap in year t

P_{t-1}.....authorized price-cap in year (t-1)

RPI.....annual inflation index (Retail Price Index)

X.....productivity offset

This formula determines the authorized price (tariff) a grid operation can set within a regulatory period, incorporating also efficiency improvements (based on cost benchmarking) over the years.

Regardless of specific investments into the grid infrastructure in the context of RES-E integration or investments in general, any investment decision of a grid operator is based on the basic economic criterion that maximises revenues minus costs over a predefined period.

[12] Besides extra cost drivers caused by large-scale RES-E integration there exist a variety of further inherent cost drivers for distribution grid operators. The main "traditional" cost drivers on distribution networks are the provision of overall capacity taking into consideration power flows, voltage level and fault level issues, and the time of use as this drives overall peak requirements. Absolute volume delivered on the distribution system usually is not to be a significant cost driver by distribution grid operators. Furthermore, regulatory incentives to maintain predefined levels of quality of service and to minimize losses also have significant influence on the cost basis of distribution grid operators (see e.g. DTI (2006)).

4.5 Forward-looking regulatory framework supporting large-scale RES-E integration

Two exemplary implementations of forward-looking and RES-friendly legislative frameworks concerning electricity grid regulation shall be presented in subsequent sections. The selection of the UK and Germany is not intended to exclusively demand best practice regulation to be in place in those two countries but shall introduce attempts to improve the framework conditions for developing RES by incentivising grid operators to bear specific additional investment costs or simply by implementing a well defined shallow grid integration approach.

4.5.1 Recent innovations in the electricity grid regulation model in UK

The UK has a long tradition in regulating its electricity distribution grids based on incentive regulation models. Already in 1995 the regulatory authority has implemented price-cap regulation. Although the price-cap regulation model has fulfilled its purpose (i.e. improving cost efficiency) in the two regulatory periods from 1995-2000 and 2000-2005, in the course of time the disincentives for investments into the electricity distribution grid infrastructure have become increasingly obvious. Moreover, in the UK empirical evidence has become visible on the reluctance of investments into the electricity distribution grid infrastructure.

Therefore, in 2005 fundamental amendments of the distribution grid regulation model have been conducted, trying to trigger both: (i) traditional investments into the distribution grid for maintenance of the infrastructure assets and (ii) extra investments to provide a level playing field for accelerated grid integration of DG/RES-E generation technologies. More precisely, the two dimensions of changes of the incentive regulation model in the UK are as follows:

- the philosophy of allocating DG/RES-E grid integration costs has been changed from "deep" towards "shallow" charging and
- the extension of the traditional price-cap regulation formula now explicitly considers an "ex-ante" element, enabling direct socialisation of extra grid-related costs for DG/RES-E integration in the grid tariffs.

In detail, the following amendments of UK's incentive regulation model have been conducted in April 2005 (see e.g. DTI (2006)):

- <u>Same Boundaries on both Ends of the Grid:</u> Prior to April 2005, demand and generation customers were charged differently on distribution grid level. DG/RES-E generators paid connection charges for all measures required to integrate them into the distribution grid (i.e. deep integration approach) whereas demand customers paid more limited connection charges (i.e. shallow integration approach).[13] In April 2005, a common connection boundary has been introduced across generation and demand, i.e. additional DG/RES-E generators connected to the distribution grid now also pay "shallow" connection charges.
- <u>Socialisation of Integration Costs:</u> Electricity distribution grid operators are allowed to recover their grid-related connection and integration costs of DG/RES-E generation facilities directly in the distribution grid tariffs by a combination of pass through (80% of connection costs) and an incentive per $kW_{DG/RES}$ connected (2.16 €/$kW_{DG/RES}$ (singular) and 1.44€/ $kW_{DG/RES}$/yr (annually)).

[13] Electricity distribution grid operators are provided with a revenue stream from demand customers by so-called 'Distribution Use of System Charges (DUoS)' covering the ongoing provision of the distribution grid and spreading the cost of connection of demand customers over the long-term.

- Innovation Funding Incentive (IFI): The Innovation Funding Incentive (IFI) is intended to provide funding for particular DG/RES-E integration projects focused on the technical development of distribution networks to deliver extra value (i.e. financial, supply quality, environmental, safety) to end consumers. IFI projects can incorporate any aspect of distribution system asset management including connection of DG/RES-E generation facilities. A distribution grid operator is allowed to spend up to 0.5% of its annual revenue on eligible IFI projects and can socialise a significant amount of associated costs from its network users (e.g. 90% in 2005/2006).
- Registered Power Zones (RPZ): In contrast to the IFI, Registered Power Zones (RPZs) are focused specifically on the connection of DG/RES-E generation facilities to distribution grids. RPZs are intended to encourage electricity distribution grid operators to develop and demonstrate new, more cost effective ways of connecting and operating DG/RES-E generation facilities. For licensed RPZs, the incentive element per $kW_{DG/RES}$ of DG/RES-E generation facility connected is increased for the first five years of operation from 2.16 €/$kW_{DG/RES}$ to 4.3 €/$kW_{DG/RES}$.

4.5.2 Recent innovations in the electricity grid regulation model in Germany

Germany's track record in RES-E development is among the most impressive and successful in Europe. While historically this success is owed to a timely stable and economically favourable promotion mechanism, recent legislation strengthens transparency in the rules for RES-E grid access and tariffing of grid related services.

Legislation on the promotion of renewable energy sources in Germany dates to the year 1991. In 2000 the renewable energy act (EEG) was put in place and amended in 2004 as well as in 2009. This design of a national promotion schemes acted as a model, which has been copied by many countries.

Regulations for access to the grid define a strictly shallow approach for connection cost allocation: Plant operators have to bear costs for the – immediate and priority - connection of the power plant to the nearest connection point providing sufficient voltage levels. In case of necessary reinforcements or extensions for using this connection point, grid operators have to bear corresponding costs or extra costs for the connection to a more distant location and are able to socialise these costs via grid tariffs.

Above this, special legislation for the connection of offshore wind farms has been put in place: In an enactment facilitating planning procedures for infrastructure projects (*Infrastrukturplanungsbeschleunigungsgesetz*) (see BGBl. I 2009) transmission system operators are committed to provide transmission lines linking substations of offshore wind platforms to technically and economically best suitable connection points of the existing electricity grid infrastructure. These transmission lines have to be put in place before the commissioning of offshore wind farms, construction of which started until end 2011. Corresponding costs on the side of grid operators are eligible costs to be socialised via grid tariffs. This regulation aims at streamlining planning procedures and facilitating financing of offshore wind projects (as financing of transmission lines has not to be borne by plant operators). At the same time, inefficient spending of electricity consumers' money for parallel submarine infrastructure shall be avoided.

German provisions do not provide extra incentives for the connection and integration of RES-E for grid operators (as is the case in the UK), but define clear responsibilities for cost allocation on the basis of a shallow approach of cost charging. In the case of offshore wind integration a – timely limited – super-shallow approach is applied.

4.5.3 Recommendations for amendments of incentive regulation models

Recent innovations of the electricity grid regulation model in UK demonstrate the way forward for amending the traditional incentive regulation approaches enabling large-scale RES-E grid integration. A precondition for RES-E grid integration – as well as the implementation of smart grid concepts in the long-term – is the establishment of common connection boundaries both on the generation and demand side. Compared to the status quo, this implies shallower RES-E connection charging policies in almost all EU Member States (see Table 5.2). Moreover, integration policies like that would go even more in line with the basic unbundling principles of the EC-Directives.

German grid regulation does not provide comparable incentives for the integration of RES-E generators but defines clear boundaries for responsibilities (concerning costs) between plant operators and grid operators. The German incentive regulation model for grid operators does account for investment costs due to RES-E integration and therefore these costs on the side of grid operators for extension and reinforcement can be handed through into system charges in principle. These charges have to be approved by the regulatory authority.

The overarching amendment of the traditional incentive regulation model, however, has to be an extension of the traditional grid regulation formula towards forward-looking elements for remuneration and/or socialisation of RES-E grid integration costs. Therefore, besides the well-known (1+RPI-X) factor an additional term has to be implemented into the existing incentive regulation model fulfilling at least the following features:

- Consideration of a mechanism to directly socialise – at least parts of – grid connection, grid reinforcement and grid extension costs in the distribution grid tariffs (e.g. direct cost pass through). In order to maintain locational signals, variable capacity (€/kW_{RES}/yr) or preferably variable volume based (€/kWh) system charges having to be paid by RES-E generators directly to grid operators)[14] similar to UK's recently modified incentive regulation model, need to be implemented.
- Provision of some kind of cost-reflective locational signals for RES-E generators, e.g. on the basis of forward-looking long run incremental costs (LRIC) rather than solely in relation to the direct costs incurred of a specific connection of a single RES-E generation facility.[15] This approach is supposed to minimise the problems associated with first movers and free-riding in case of more than one RES-E generator applying for connection at a certain point of the existing grid infrastructure.
- Consideration of a mechanism to directly cover and/or remuneration operational costs allocated to innovative RES-E grid integration projects (i.e. personnel costs for research, feasibility studies and preparatory operations of RES-E grid integration projects) in the incentive regulation model.
- Avoidance of unmanageable complexity of additional terms in an extended incentive regulation formula.

[14] The volume based part of the use of system charge allocated to generators usually is called 'Generation Use of System Charges (GUoS)'.

[15] In general, the decision on the boundary between fixed connection charges and volume based 'Generation Use of System Charges (GUoS)' – both having to be paid by RES-E generators to grid operators – needs to take account of the desirability of reflecting costs to RES-E generators on a forward-looking long-run incremental cost (LRIC) basis. These charges, furthermore, should be cost reflective and also incorporate a sensible apportionment of forward-looking LRIC providing both correct signals and cost-recovering mark-ups. However, according to the Ramsey-Boiteux rule (see e.g. Ramsey (1927) and Boiteux (1971)) the mark-up should minimise distortions. This also implies that usually 'Generation Use of System Charges (GUoS)' and 'Distribution Use of System Charges (GUoS)' are set differently, due to the differences in price elasticities of generation and demand customers.

Exemplarily, an extension of the traditional incentive regulation formula (e.g. price-cap and/or revenue-cap regulation model) can be indicated as follows (see e.g. Auer (2007)):

$$P_t = P_{t-1} * (1 + RPI - X) + \Delta C_{RES\,i,\,j} * \Delta kW_{RES\,i,\,j} * (1 + RPI - LR_{\Delta C_{RES\,i,\,j}}) \qquad \text{(Equation 3)}$$

$\Delta C_{RES\,i,\,j}$ specific costs for a grid operator caused by the integration of a RES-E generation technology i into an existing grid topology and/or smart grid concept j

$\Delta kW_{RES\,i,\,j}$ installed capacity of RES-E generation technology i integrated into an existing grid topology and/or smart grid concept j

$LR_{\Delta C_{RES\,i,\,j}}$ expected dynamic learning rate and/or economies of scale of specific grid integration costs caused by the integration of a RES-E generation technology i into an existing grid topology j

It is important to note, that the analytical approach presented above only suggests the cornerstones of a possible way forward to extend the traditional incentive regulation model. Although it is still incomplete and subject to further disaggregation and empirical scaling, innovations in electricity grid regulation are obvious at least in two dimensions:

- implementation of a forward-looking element enabling ex-ante socialisation of grid related costs caused by the integration of RES-E generation,
- consideration of a dynamic element putting downward pressure on specific grid integration costs (e.g. due to technological learning and economies of scale) with increasing shares of RES-E generation.

An amendment of the traditional incentive regulation model according to the basic principles shown above finally shifts the connection boundary between the RES-E generation facilities and the existing grid infrastructure increasingly towards the RES-E generators. Moreover, if grid infrastructure related costs of RES-E integration are allocated to grid operators rather than to RES-E generators, there also exist direct interdependences with the design of RES-E promotion instruments (e.g. like feed-in tariffs).[16]

More precisely, a re-design of RES-E promotion instruments is necessary, if parts of the initial costs (previously allocated to the RES-E power plant) are assigned to the grid infrastructure (e.g. grid connection costs) and socialised via grid tariffs. For a comprehensive consideration of these interdependences including empirical modelling of RES-E deployment for different cost allocation policies of RES-E grid integration costs it is referred to e.g. Auer at al (2007).

[16] In case of tradable green certificate (TGC) support schemes of RES-E generation technologies an allocation and socialisation of several grid related integration costs (i.e. grid connection, grid reinforcement/upgrading) to the grid tariffs finally shall also result in lower certificate prices indicated on the TGC market (due to lower long-run marginal RES-E generation costs).

5 The simulation software Green*Net-Europe*

5.1 Short characterisation

The simulation software Green*Net*-Europe models investment decisions for both renewable energy technologies for electricity production (RES-E) and energy efficiency measures in the liberalised European electricity market taking into account the respective support policy framework. A specific feature is the assessment of costs for the grid integration of RES-E and their consideration for investment decisions depending on the specific regulatory framework for cost allocation.

The model covers current 27 EU Member States, the Western Balkan countries Albania, Bosnia Herzegovina, Croatia, FYR of Macedonia and Serbia and Montenegro as well as Norway, Turkey and Switzerland. Simulations are performed on country-level for the period of 2006 to 2020. A number of scenarios can be simulated by specifying

- the RES-E support policy,
- the energy efficiency policy,
- grid integration cost scenarios,
- the grid integration cost allocation policy,
- the scenario for the wholesale electricity price (low, medium, high),
- the non-economic barrier levels (business as usual and low).

Besides these parameters a comprehensive data base on potentials and costs of both RES-E and energy efficiency measures is a key input for the model.

Key results include the annual deployment of RES-E technologies on country level and related costs of grid integration for RES-E as well as realised energy efficiency potentials on the level of individual applications. Grid integration costs are split up in the cost categories grid connection, grid reinforcement, balancing and system capacity. These costs are currently assessed for wind power only as for other technologies they turn out to be minor in the considered time horizon.

5.2 The modelling approach

The following figure illustrates the simulation procedure as implemented in the Green*Net*-Europe model. For each simulation year the procedure starts with the determination of annually available potentials and corresponding costs – the so called dynamic cost resource curves - for both RES-E technologies and energy efficiency measures. For wind power also grid integration costs are assessed. Investment decisions base on information for the simulation year only (myopic approach) and result from matching supply and demand in each sub market as defined by the specific support mechanism. The resulting deployment of RES-E technologies and the realised energy efficiency potential are taken into account for the determination of the cost resource curves and the grid integration costs of the subsequent simulation year. Exogenous parameters can be selected on a yearly basis in order to reflect dynamic changes of the framework conditions.

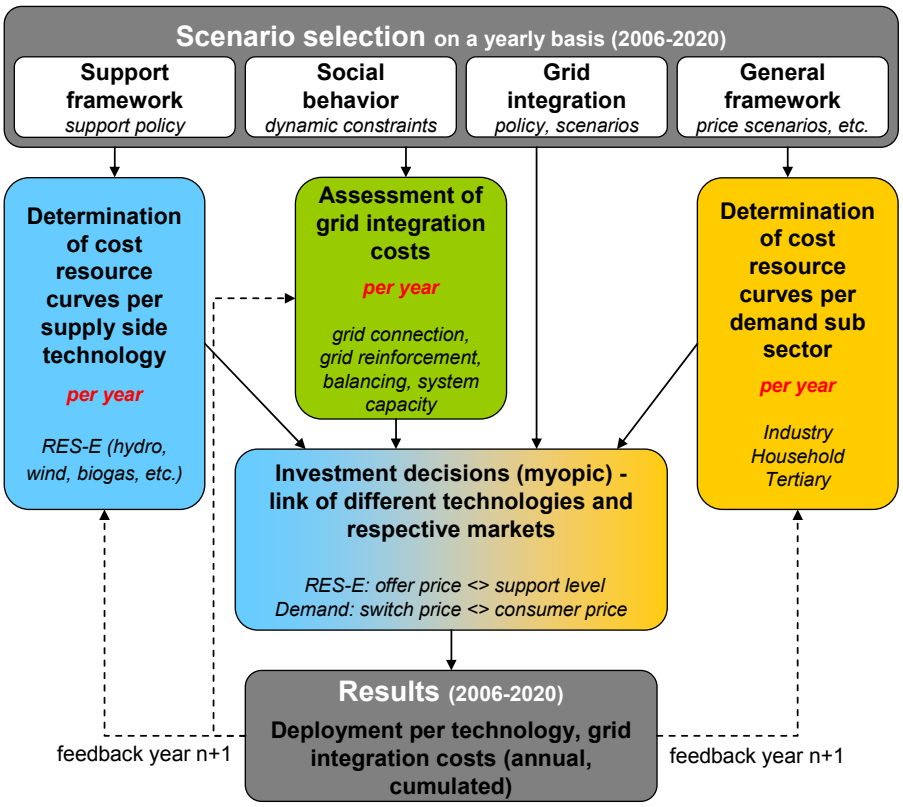

*Figure 5.1: Overview on the modelling approach of the software tool Green*Net-*Europe*

Figure 5.2 below illustrates the derivation of the dynamic cost-resource curve of a particular RES-E technology in detail. The starting point is the static cost resource curve that combines information on additional mid-term potentials for the year 2020 and corresponding long-run marginal generation costs for discrete bands (Figure 5.2, left). The different bands reflect potentials with comparable economics (e.g. in case of wind-onshore sites with similar annual full load hours, etc.). Due to a variety of barriers and constraints (industrial, technical, market, administrative, societal) not the entire potential within a particular band can be utilized in one year. Therefore, the achievable potential per year has to be scaled down accordingly (Figure 5.2, right).

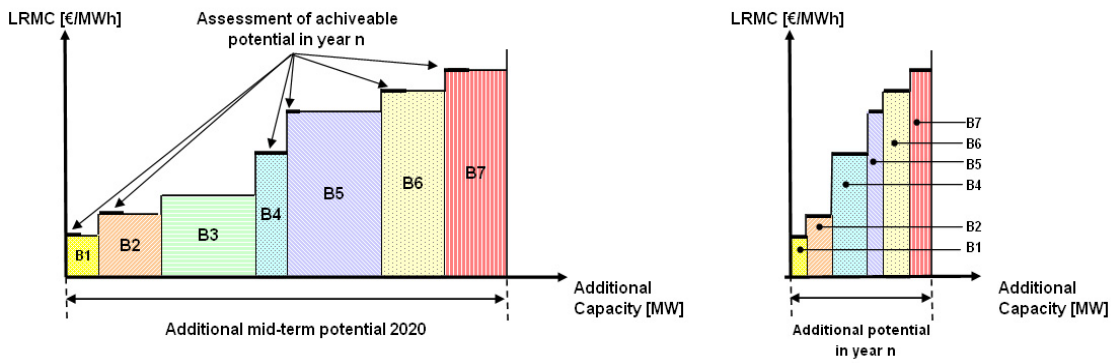

Figure 5.2: Cost-resource curve assessment of a particular RES-E generation technology: Additional mid-term potential in year 2020 (left) and derivation of achievable potential in year n (right)

The absolute level of the long-run marginal generation costs per band is derived endogenously in the Green*Net*-Europe model as well, taking into account the effect of technological learning. Fixed generation costs decrease each year depending on the implemented potential in the previous year (n-1) and the assumed learning rate on technology level.

Extra costs for system operation (system balancing and system adequacy), grid connection and grid reinforcement are assessed annually and – in case of selection – allocated to the marginal generation costs of the corresponding RES-E technology as illustrated in Figure 5.3. In this way economic implications of the allocation of integration cost are modelled. As already mentioned, this feature is currently implemented for wind power only but the approach can be applied for any technology.

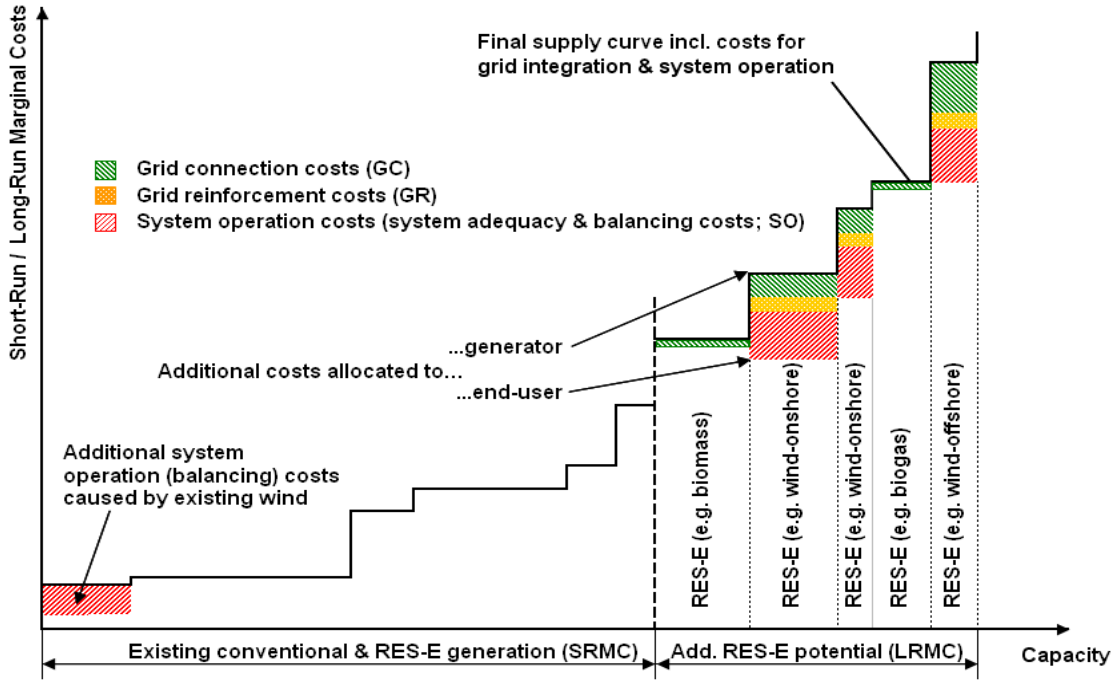

Figure 5.3: Implementation of extra system operation costs, grid connection costs and grid reinforcement/upgrading costs into the supply curve of the GreenNet-Europe model

Cost resource curves are determined for energy efficiency measures in industry, the household and the tertiary sector following the same logic. The implemented methodology determines on an annual basis both (i) prices for switching to a more efficient demand side technology and (ii) corresponding potentials of electricity savings. The switch price at which the investment in an energy efficient technology becomes economic is determined by the fixed and operating costs; potentials are determined endogenously on an annual basis taking into account a replacement rate for each appliance.

Finally, for modelling investment decisions separate markets that result from specific support mechanisms on country level are considered[17]. Promotion instruments for RES-E generation technologies include the most important price-driven strategies (feed-in tariffs, tax incentives, investment subsidies, subsidies on fuel input) and demand-driven strategies (quota obligations based on tradable green certificates, tendering schemes). As Green*Net*-Europe is a dynamic simulation tool, the user can change RES-E policies and parameter settings within a simulation run on a yearly basis. Furthermore, several instruments can be set for each country individually.

[17] The support of RES-E often leads to the separation of markets i.e. RES-E technologies do not compete with conventional technologies in the wholesale market but are handled in separate markets with either specified price or demand. A technology that is supported via a Feed-In Tariff is treated in a separate market with a fixed price. The quantity (the installed capacity) depends on the economics of available potentials – only those potentials with LRMC lower than the Feed-In Tariff are realised. Support via a quota system leads to market separation as well. In this case the demand is fixed while the price is determined by the marginal potential or technology. Least expensive potentials needed to fulfil the quota are realised. Depending on the design of the quota system RES-E technologies are competing (overall quota) or not (technology specific quota). There are also schemes in place that do not imply separate markets (investment subsidies, tax incentives, etc.).

Investment decisions on the demand side also base on the approach of the willingness to invest. In general, the willingness to invest into more efficient demand side energy saving technologies is modelled as the economic trade-off between a new technology and the existing one. Green*Net*-Europe models established policy promotion instruments on the demand side as well.

Wholesale electricity price projections on the conventional power market are implemented exogenously. Three different wholesale price scenarios, which reflect a reasonable bandwidth for the development of major fundamental parameters up to 2020, can be selected[18].

For a comprehensive description of the Green*Net*-Europe modelling approach it is referred to Huber et al (2004). An even more detailed description of the derivation of the dynamic cost-resource curves as well as the comprehensive Green*Net*-Europe data base is conducted in Resch (2005).

5.3 Determination of potentials and costs of RES-E generation in Europe

As already stated above, the starting point for deriving the dynamic potential is the determination of the additional mid-term potential for electricity generation for a specific technology in a specific country.[19] The additional mid-term potential is the maximum additional achievable potential assuming that all existing barriers can be overcome and all driving forces are active. The so-called 'dynamic potential' is the according maximal achievable potential for the year n. RES-E generation follows such a time path in the case of sufficient economic incentives and minimal non-economic barriers. Without any support the so called economic potential can be realised. The actual time path lies in between both depending on the respective framework. To illustrate this more clearly, the relation between the different potential terms is depicted in Figure 5.4.

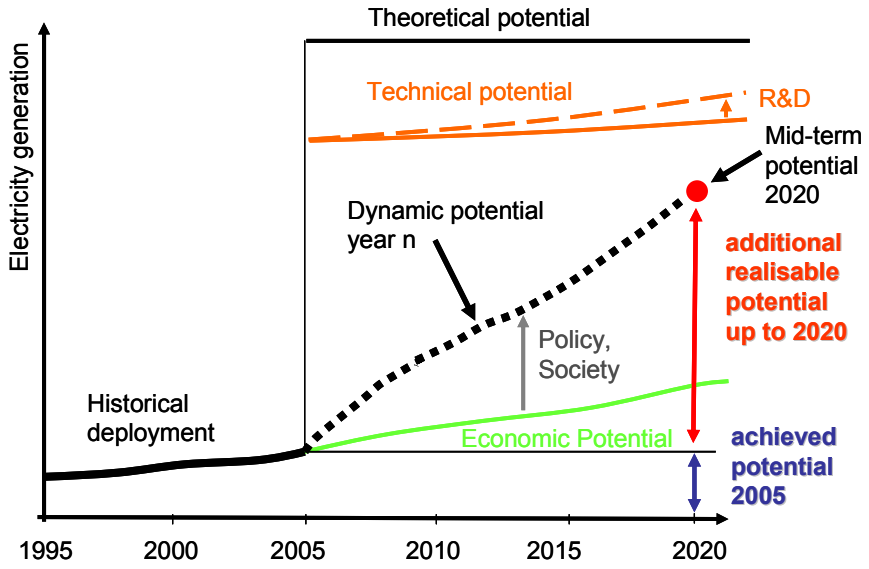

Figure 5.4: Methodology for the definition of different RES-E potentials

In the toolbox Green*Net*-Europe the additional mid-term potential for electricity generation refers to the year 2020. The methodology for the analysis of the potential varies significantly from one technology to another.

[18] Wholesale price scenarios are calculated with the Green-X model (cf. Resch et al. (2007)) based on demand and fuel price projections of the European Commission (EC (2008), EC (2006a) and EC (2006b)).

[19] Note: While the additional mid-term potential represents an important input parameter in the Green*Net*-Europe database, the additional annual potential (dynamic potential) is one of the essential output parameters of the cost curve development.

In most cases a 'top-down' approach is used (e.g. for wind energy, photovoltaics). In a first step the technical potential for one technology in one country for 2020 has to be derived by determining the total useable energy flow of a technology. Secondly, based on step one, the mid-term potential for the year 2020 is determined by taking into consideration the technical feasibility, social acceptance, planning aspects, growth rate of industry and market distortions. The additional mid-term potential is given by the mid-term potential minus existing penetration plus decommissioning of existing plants.[20]

For a few technologies, a 'bottom-up' approach has been more successful (e.g. for geothermal electricity), i.e. by looking at every single site (or band), where energy production seems possible and by considering various barriers, the additional mid-term potential is derived. The accumulated value of the single band yields the additional potential for one technology in one country.

In this context, biomass has to be treated specifically as the total primary energy potential is restricted. The allocation of resources to the different options - pure electricity generation, CHP generation, heat generation or biofuel - depends on the specific economic conditions. Therefore, in the economic assessment, support schemes in the respective sectors are considered and reflected by linking the values of different options in the database.

Figure 5.6 and Figure 5.5 depict the achieved and additional mid-term potentials for RES-E technologies in the 35 covered countries on country and technology-level respectively. In EU-27 Member States the already achieved potential for RES-E generation equals 509 TWh[21], whereas the additional realisable potential up to 2020 is 1175 TWh. Also future RES-E potentials are distributed heterogeneously amongst EU-Member States. France, Germany, UK, Spain and Italy show the highest absolute numbers and represent together two third of the additional potential within the EU.

While for established technologies like hydro power and geothermal electricity additional potentials are quite limited compared to the existing utilisation, considerable potentials are identified for new RES-E technologies. With 505 TWh, wind power shows the highest additional potential in the EU, which is shared equally between onshore and offshore utilisation. The additional electricity generation potential up to 2020 for biomass in terms of solid resources and biogas amounts to 306 TWh. Further promising RES-E options include tide and wave energy, PV and solar electricity.

[20] To use the potential in the database of the toolbox Green*Net*-Europe, the additional mid-term potential obtained on technology level (in one country) must be broken down to band level.

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

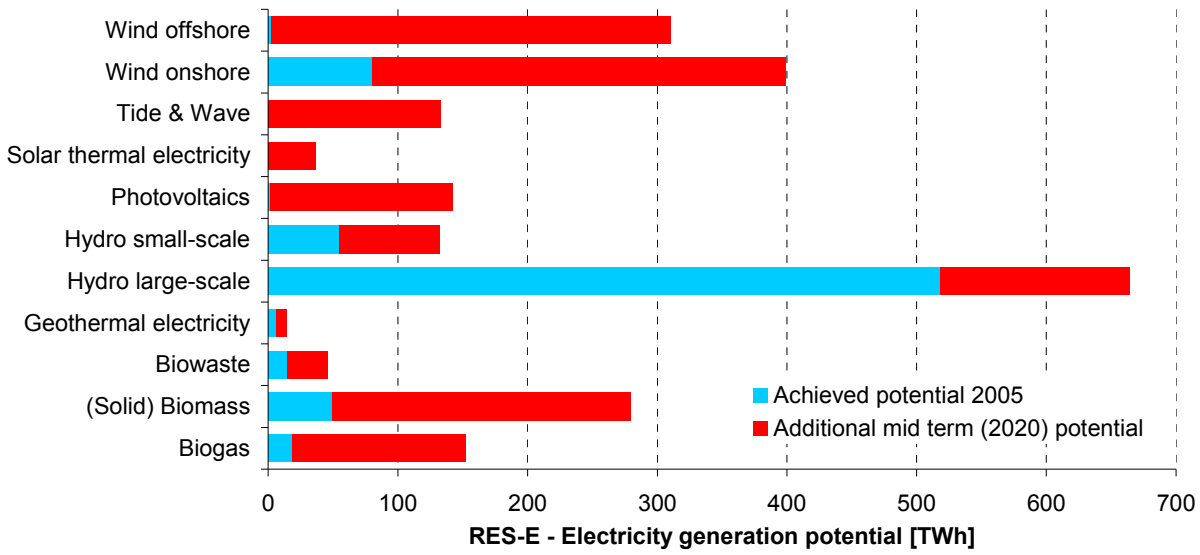

Figure 5.5: Achieved (2005) and additional mid-term potential (2020) for electricity from RES in all 35 implemented European countries

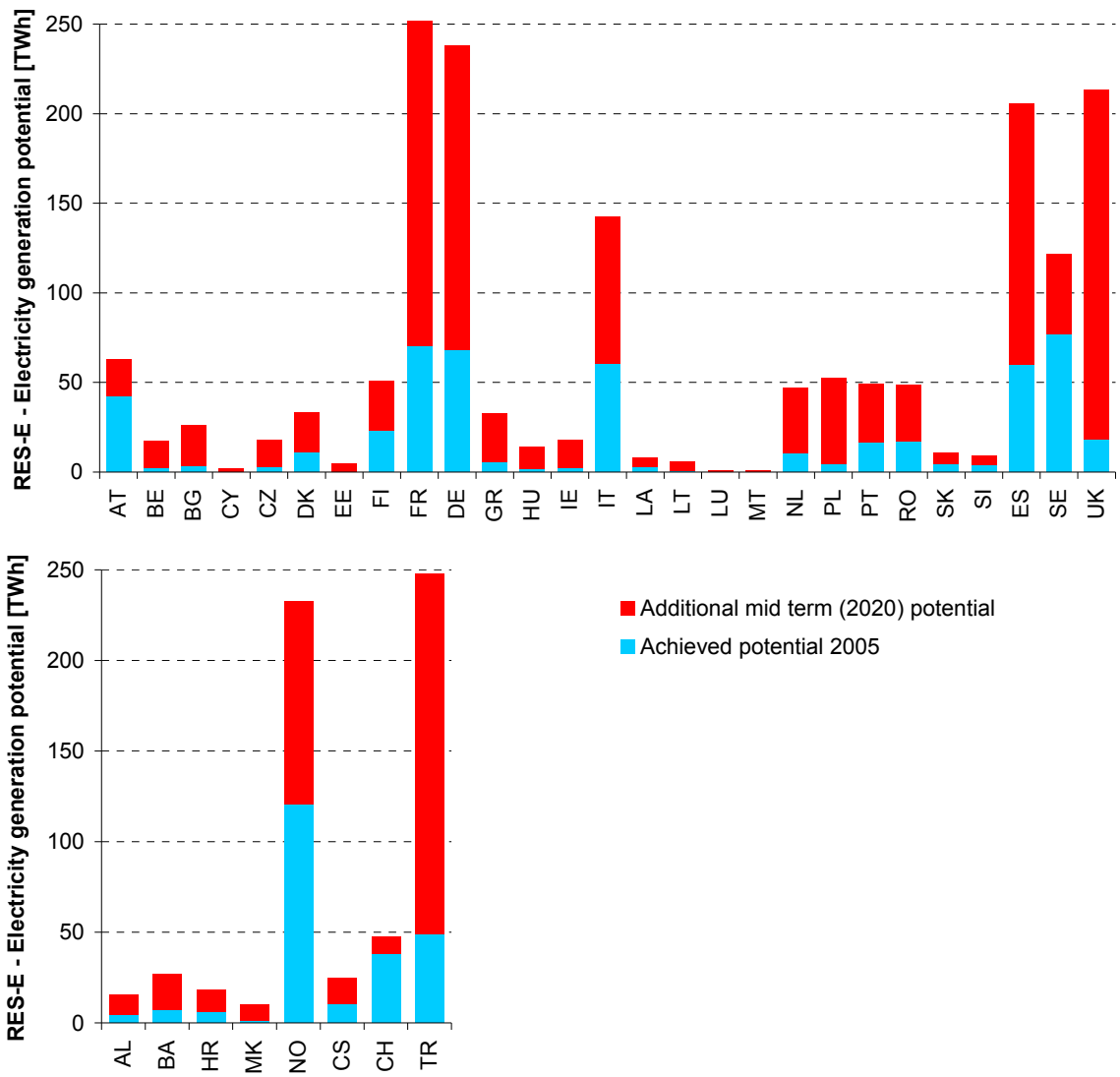

Figure 5.6: Achieved (2005) and additional mid-term potential (2020) for electricity from RES in EU-27 Member States (above) and remaining countries covered in the GreenNet-Europe model (below).

Figure 5.7 depicts long-run marginal generation costs[22] by RES-E technology. Two different settings are applied describing the payback time:[23] On the one hand, a default setting of 15 years is applied to all RES-E options (left)[24], on the other hand, the payback time is set equal to the technology-specific life time (right). The broad range of costs for several RES-E technologies represents resource-specific conditions in different regions (countries). Costs also depend on technological options available (e.g. compare co-firing and small-scale CHP plants for biomass).

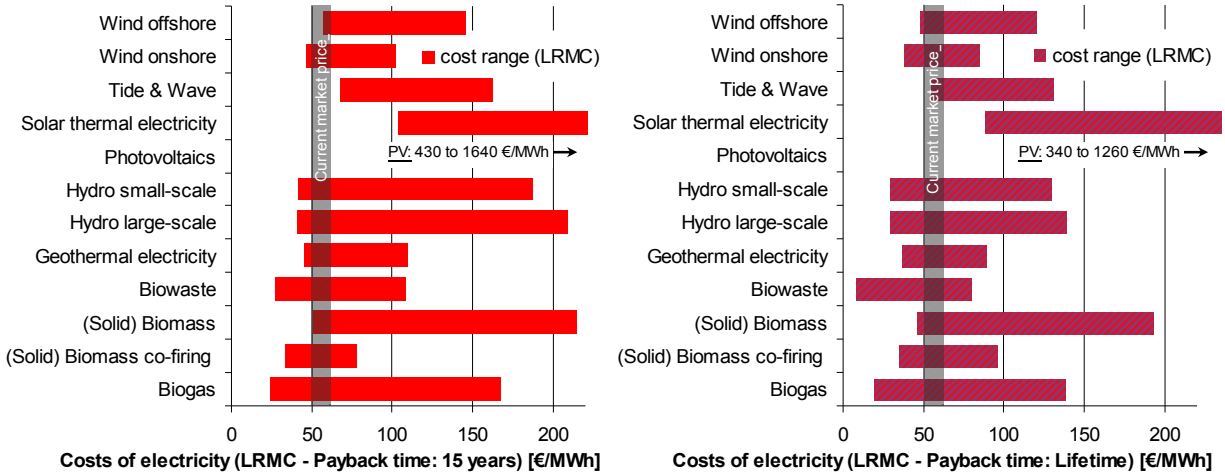

Figure 5.7: Bandwidth of long-run marginal generation costs (for the year 2005) of different RES-E technologies for several countries covered – based on a default payback time of 15 years (left) and a payback time equal to lifetime (right).

5.4 Grid and system related costs of RES-E grid integration

5.4.1 Grid infrastructure costs

In general, the integration of any power generation technology into the existing power grid is connected with investments in grid infrastructure. This is also the case for the grid integration of RES-E power plants. In this context two different aspects have to be considered:

- The connection of RES-E power plants to the existing power grid: the corresponding investments are indicated as grid connection costs (GC).
- Reinforcements of the existing power grid due to RES-E grid integration: the corresponding investments are indicated as grid reinforcement costs (GR).

In the following chapter we provide a definition of both cost components.

Grid connection costs

The term grid connection indicates the physical connection of a RES-E power plant or a number of RES-E power plants (e.g. a wind farm) to the nearest connection point of the existing grid being technically and economically feasible i.e. the so called external grid. It does not comprise the internal grid connection of e.g. single turbines of a wind farm with the common connection point of the site.

[22] Long-run marginal generation costs in relation to the expected market value of electricity determine the willingness to invest in new generation capacity.
[23] For both cases an interest rate of 6.5% is used.
[24] A payback time of 15 years aims to reflect the investor's point-of-view in competitive, liberalised markets.

Grid connection usually comprises the power line/cable connecting the common connection point of the site with the connection point of the existing grid (in general the substation) as well as modifications and extensions of the corresponding substation.

For offshore wind farms the connection point of the existing grid in any case is located onshore independent of the underlying connection concept. I.e. even if the high voltage power grid is extended to the sea in the sense of a coordinated (and least cost) grid connection of offshore wind farms, the grid connection comprises even this high voltage power line. Figure 5.8 illustrates the system bounds reflected in Green*Net* for both connection concepts – the individual connection of single wind farms to the existing onshore power grid and the coordinated connection of a number of wind farms located in a certain area.

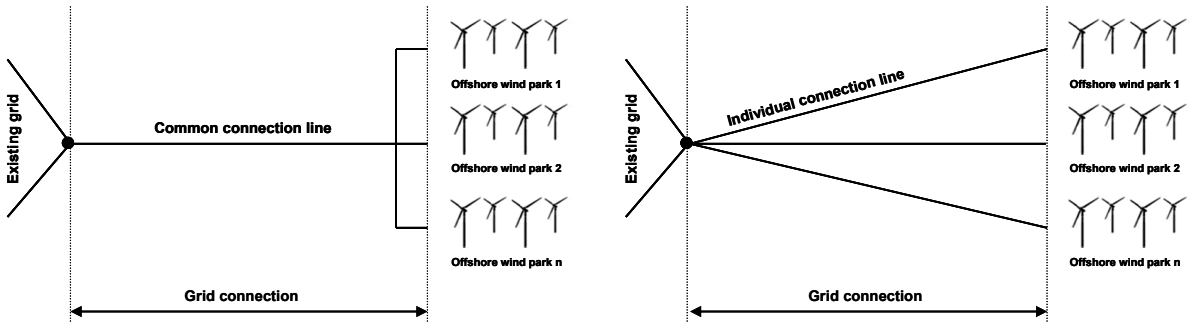

*Figure 5.8: Illustration of the term grid connection as used in Green*Net *for the case of an individual connection of offshore wind farms to the existing onshore power grid (right) and coordinated connection of offshore wind farms via a common link (left)*

The term grid connection costs indicates several costs for connecting a RES-E power plant or a number of RES-E power plants (e.g. a wind farm) to the existing grid (i.e. costs of the external grid).

In general, grid connection costs of RES-E generation technologies are determined by a variety of factors. Most important once are:

- the distance between the power plant and the point of common coupling to the grid;
- the possibility to apply standardized equipment (for substations, cables, etc.)
- the necessity to extend the local grid and/or to switch to a higher voltage level.

In the past, grid connection costs have been comprehensively discussed for wind energy. But, also for traditional RES-E technologies – such as small hydropower – grid connection often appears to be a significant barrier. In general, grid connection is an important economic constraint for those RES-E generation technologies being mainly determined by the local availability of resources. Therefore, often a compromise between best sites and proper grid conditions appears.

Grid reinforcement costs

The term grid reinforcement indicates several reinforcements of the existing transmission grids necessary to integrate RES-E power plants into the power grid. Reinforcements of the distribution grid are not taken into account in Green*Net* due to the lack of empirical data. Whilst reinforcements of the distribution grid usually can be clearly allocated to the originator, reinforcements of the transmission grid may on the one hand become necessary for a number of reasons (increased power trade, modification of the spatial distribution of power demand and/or supply) and on the other hand imply positive externalities for a number of players in the power market (traders, consumers, utilities, RES-E generators, etc.). This makes it difficult to allocate reinforcement

measures in the transmission grid to a certain power generation technology (e.g. wind power or even nuclear power).

Grid reinforcement measures include the upgrade of existing power lines and/or the installation of additional power lines both resulting in an increased resulting capacity.

The term grid reinforcement costs indicates several costs for reinforcements of the existing transmission power grids that are in this case allocated to wind power.

5.4.2 Costs related to effects on the operation of and investments in conventional power capacities

System analysis addressing the impact of intermittent wind power generation on the operation of power systems carried out so far shows that wind power is affecting system balancing on different time scales.

Balancing costs

In the time scale from minutes to several days wind power is – as a result of its variable nature – affecting the operation of conventional power plants and due the limited accuracy of wind power forecasts requiring additional reserves and regulating power, both effects causing additional costs for the power system.

This issue in Green*Net* is indicated balancing of wind power and corresponding costs are indicated as balancing costs of wind power. It is important to mention that these costs are occurring as soon as wind power is integrated into power systems.

System capacity costs

When considering impacts on the power system in the medium to long-term (i.e. several years ahead) it becomes clear that wind power due to its limited contribution to system capacity requires a sort of back-up in order to be comparable with conventional power generation. Again, additional costs can be attributed to these system capacity requirements.

This effect is referred to as system capacity and corresponding costs are indicated as system capacity costs of wind power. System capacity costs – other than balancing costs – are not incurred until excess capacity in the power system becomes scarce and corresponding incentives for investments in new conventional capacities are visible at power markets in form of increasing market prices. However, these costs can be allocated to wind power as well and in the software tool Green*Net* it is assumed that costs are incurred without time delay.

5.5 Methodology for modelling grid and system integration costs

The following chapters describe approaches for modelling grid integration costs in the software tool Green*Net*-Europe.

5.5.1 Grid connection costs

In practice, grid connection costs are – independent of the power generation technology – considered as part of the total investments and are therefore paid by the RES-E generator. An alternative approach is the allocation of grid connection costs to the grid operator in order to minimize barriers for the grid access of (new) generators. The software tool Green*Net*-Europe simulates both cases – the allocation of grid connection costs to the RES-E generator and to the grid operator. In the latter case the grid operator socializes costs, i.e. the end user finally pays for grid connection in form of higher grid tariffs.

Costs for connecting wind power are implemented in the Green*Net*-Europe model based on the analysis of empirical data:

- for wind onshore grid connection costs are assumed to be 8 % of specific investment costs and
- for wind offshore bands with similar distances to shore are clustered and allocated to four different cost levels ranging from 10 to 25 % of the corresponding total specific investment costs.

For both wind on- and offshore a depreciation period of 15 years and an interest rate of 6.5 % are applied.

5.5.2 Grid reinforcement costs

Within the last years a number of studies have been carried out addressing needs for grid reinforcements due to the integration of wind power. The most comprehensive overview on literature and comparison of specific reinforcement costs (per kW wind power installed) is given in Holttinen et al., 2008. Specific transmission grid reinforcement costs of investigated studies range between 53 and 162 €/kW depending on country specific conditions and investigated wind penetrations.

To derive cost scenarios grid integration costs are translated into specific numbers (per MWh wind generation) and drawn as a function of the corresponding share of wind generation on projected gross demand in the year of scope. Therefore we assume full load hours as quoted in the respective study, a depreciation period of 40 yrs and a (real) interest rate of 4.5 %. The following figure illustrates results of the comparison of grid reinforcement costs and related scenarios used for the model implementation in Green*Net*-Europe. Cost data stems from study results listed in Holttinen et al., 2008 and information gathered within a literature review.

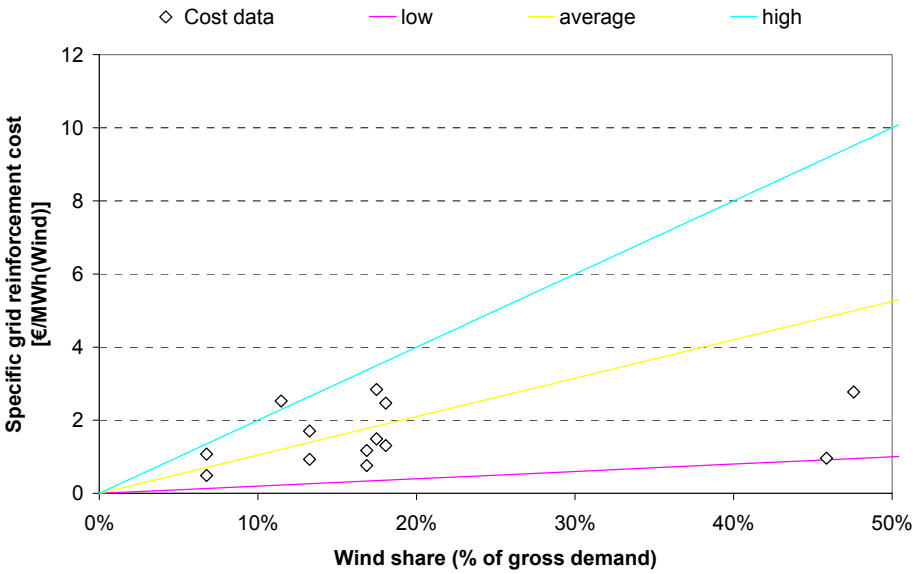

*Figure 5.9: Comparison of grid reinforcement cost data and related model implementation in Green*Net*-Europe*

In practise for growing wind shares grid reinforcement costs increase stepwise with each investment in grid infrastructure necessary to accommodate additional wind power capacities. In the model grid reinforcement costs are assumed to increase continuously. It should be further noted that drawn scenarios tend to underestimate overall grid reinforcement costs as reinforcements on distribution grid level are neglected. On the other hand, positive externalities of increased transmission capacities for other stakeholders are not taken into account either.

5.5.3 Balancing costs

Balancing costs are expressed as specific costs (per MWh wind) depending on the wind share in the corresponding system. The three scenarios illustrated in Figure 5.10 reflect the bandwidth of balancing costs indicated in Holttinen et al., 2008. For high wind shares, specific costs range between 1 and 5.5 €/MWh.

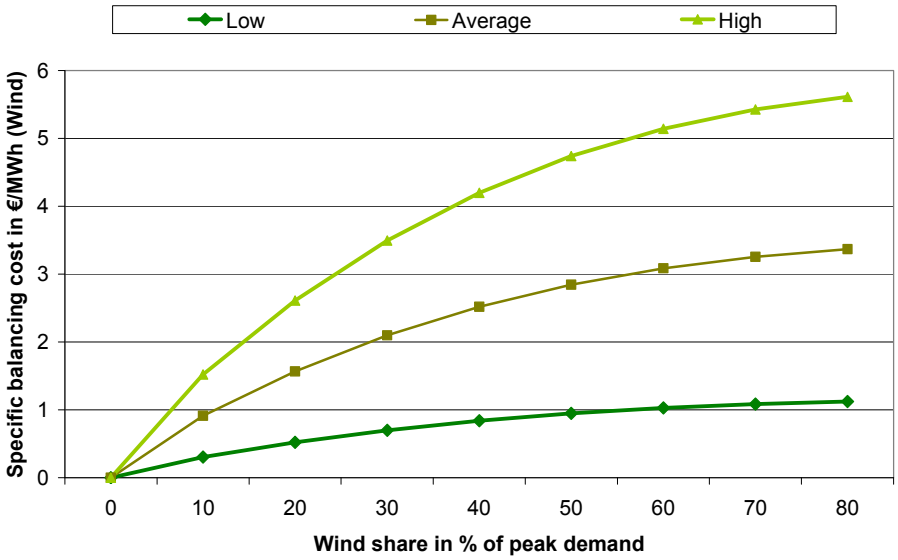

*Figure 5.10: Model implementation of balancing costs of wind power in Green*Net-*Europe based on a comparison of study results in Holttinen et al. (2008).*

5.5.4 System capacity costs

The core objective of the analysis of system capacity requirements is to determine the contribution of intermittent RES-E generation to generation adequacy. In other words, to determine the amount of conventional capacity that can be displaced by intermittent RES-E capacity, whilst maintaining the same degree of system security.

The ability of wind power to replace conventional capacity has been discussed since the renaissance of this energy conversion technology in the end of the 1970s. The parameter used to quantify this ability is the so called capacity credit which is usually defined as follows (see e.g. Giebel (2005)):

"The Capacity Credit (CC) assigned to a regenerative conversion plant is the fraction of installed (regenerative) capacity by which the conventional power generation capacity can be reduced without affecting the loss of load probability(LOLP)[25]"

Within the last decades a number of studies have been carried out aiming at quantifying the CC for different power systems. When comparing results from different studies one has to be aware that the modelling approach applied as well as major assumptions may vary and affect the result to a considerable extent. Therefore we implement different scenarios for the CC in Green*Net*-Europe based on recent analyses (see Figure 5.11).

[25] Loss Of Load Probability (LOLP) is the probability that a loss of load event occurs, i.e. that the electricity demand of a power system cannot be met by its own power generation. As this definition doesn't take into account the possibility of power imports from neighbouring systems one has to be aware that the loss of load event does not represent the probability of a black out of the power system. Typically, system operators aim for 1 event in 10 years (or better, of course). For the LOLP, the match between resource and demand is decisive, as well as the response times of the existing power plants. Power supply systems with a high percentage of storage (e.g. pump storage) can accommodate higher penetrations of wind energy than supply systems consisting solely of nuclear and coal fired plants (Giebel (2005)).

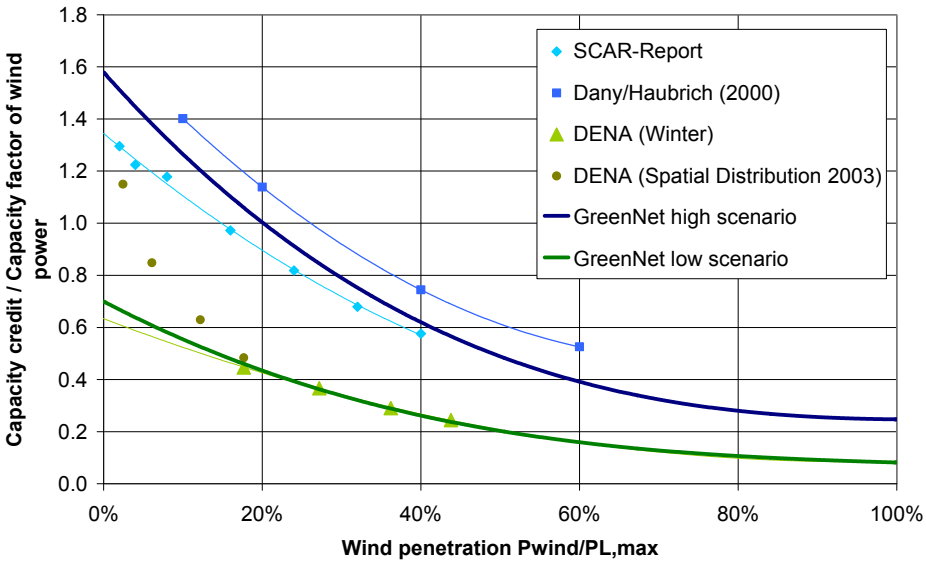

*Figure 5.11: Definition of Capacity Credit scenarios implemented in the Green*Net*-Europe model. Sources: ILEX/UMIST (2002), Dany/Haubrich (2000), DENA (2005).*

In Green*Net*-Europe the CC scenarios are implemented as illustrated in Figure 5.12 below.

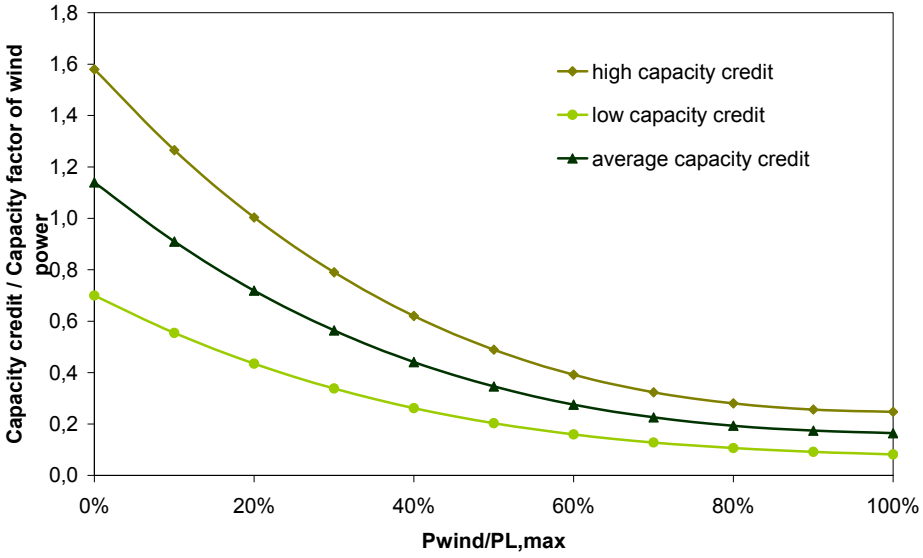

*Figure 5.12: Implementation of CC scenarios in the simulation software Green*Net *-Europe*

The modelling approach

The methodology applied to calculate the system operation costs is described in the following.

First, the annual wind generation is calculated from installed capacity in MW and the full load hours.

$qel = MWwind * Hel\_wind$

where

qel	…	Quantity of annual wind generation [MWh/yr]
MWwind	…	Installed capacity of wind [MW]
Hel_wind	…	Full load hours of wind generation [h/yr]

Then the amount of conventional capacity replaced by wind power – i.e. the capacity of the so called thermal equivalent – is determined based on the capacity factor of the generation technology replaced (e.g. generation from CCGT (Combined Cycle Gas Turbine) power plants).

$MWthermal\ equivalent\ gross = qel / (CF * 8760)$

where

MWthermal equivalent gross	…	Gross capacity of thermal equivalent [MW]
CF	…	Capacity factor [%]

When taking into account the CC of wind power (according to the scenarios illustrated in Figure 5.12 above), only part of the capacity of the thermal equivalent has to be provided in form of system capacity:

$MWthermal\ equivalent\ net = MWthermal\ equivalent\ gross * (1 - CCwind / CFwind * Hel\_wind / 8760)$

where

MWthermal equivalent net	…	Net capacity of thermal equivalent having to be installed [MW]
CCwind / CFwind	…	Ratio of Capacity credit to Capacity Factor of wind power according to Figure 5.12
Hel_wind	…	Full load hours of wind generation [h/yr]

Finally, specific capital costs of the capacity needed to back up wind power (typically OCGT (Open Cycle Gas Turbines) units are used for system purposes) are determined as follows:

$Csystem\ capacity = (a * I * MWthermal\ equivalent\ net) / qel$

where

Csystem capacity	…	Specific capital costs of system capacity [€/MWh(wind)]
a	…	Annuity factor
I	…	Investment costs of system generation technology [€/kW]

These costs can be interpreted as the corresponding capacity costs due to integrating wind power.

Below an illustrative example is shown:

E.g., 10 GW of wind capacity generates 30 TWh per annum (assuming 3000 full load hours. 4 GW of CCGT at 85% load factor produces the same annual generation as 10 GW of wind power. However, conventional capacity delivers two services, electricity production and capacity.

Without capacity credit

If one assumes that wind power does not contribute to the capacity margin at all, then to be equivalent to conventional generation, system capacity would be required in the range of the capacity of the thermal equivalent (i.e. in this case 4 GW). This capacity should come from a power generation technology being suitable for peaking operation and showing low capital costs. Corresponding annualized specific costs of an OCGT unit (fulfilling these criteria) are assumed to be 55 €/kW-yr . Thus, capital costs of 4 GW of OCGT peaking capacity are €222m per annum and 7.39 €/MWh(wind) respectively.

With capacity credit

If it is considered that wind power does contribute to system security, albeit at a smaller rate than conventional capacity, then the capacity requirement is reduced by the level of that contribution. If it is assumed that 25% of wind capacity (i.e. 2.5 GW out of 10 GW) contributes to the system, the additional OCGT capacity requirement is reduced to 4 GW – 2.5 GW = 1.5 GW. At 55 €/kW-yr the OCGT capacity costs are now €84m per annum and 2.80 €/MWh(wind) respectively.

The table below summarizes the two different approaches (with versus without capacity credit) of the example given above.

Table 5.1: Calculation of the specific capacity cost of wind power with vs. without capacity credit.

Example: Calculation of capacity cost		
Wind power capacity	**10**	**GW**
Full load hours	**3000**	**h/yr**
Wind power generation	**30000**	**GWh**
Without capacity credit		
CCGT capacity factor	85	%
CCGT full load hours	7446	h/yr
Thermal capacity equivalent	4	GW
Capacity credit wind	0	%
Capacity contribution wind	0	GW
Required back-up capacity	4	GW
Specific cost of back-up capacity	65	€/kW/yr
Annual back-up capacity cost	262	Mio.€/yr
Levelised back-up capacity cost	**8.73**	**€/MWh**
With capacity credit		
CCGT capacity factor	85	%
CCGT full load hours	7446	h/yr
Thermal capacity equivalent	4	GW
Capacity credit wind	25	%
Capacity contribution wind	2.5	GW
Required back-up capacity	1.5	GW
Specific cost of back-up capacity	65	€/kW/yr
Annual back-up capacity cost	99	Mio.€/yr
Levelised back-up capacity cost	**3.31**	**€/MWh**

In order to illustrate the bandwidth of system capacity costs of wind power the method of the thermal equivalent is in the following applied to the German power system. Depending on the capacity credit scenario taken into account, up to a wind power penetration of 10 % (as a share of installed capacity on system peak demand) system capacity costs are in the range of 0 to 4 €/MWh(wind) while for high penetrations up to 30 % a bandwidth of 2.5 to 5.5 €/MWh(wind) can be observed. For the theoretical case that wind power does not contribute to system capacity at all costs of 7.4 €/MWh(wind) are calculated independent of the wind power capacity installed.

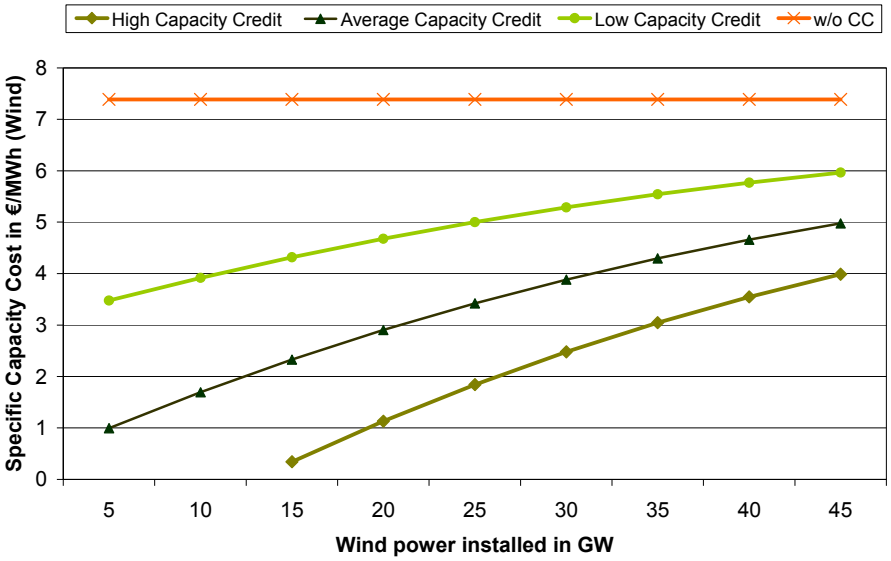

Figure 5.13: Germany – additional system capacity costs of wind power depending on the installed wind power capacity for capacity credit scenarios implemented in GreenNet-Europe.
Assumptions: Peak demand 2020: 100 GW, load factor of thermal equivalent: 85 %, specific annual capital costs of thermal equivalent: 55 €/kW-yr, capacity credit according to Figure 5.12.

5.6 Scenario selection in Green*Net-Europe*

This Chapter summarises assumptions on grid integration cost scenarios described in Chapter 5.5 and gives an overview on the current practise of cost allocation in analysed countries.

5.6.1 Integration cost scenario selection

Grid connection costs

As already described in Chapter 5.5.1 grid connection costs are modelled as a fixed share of total investment costs. For wind onshore grid connection costs are assumed to be 8 % of total investments and for wind offshore between 10 and 25 % depending on the distance to shore which is reflected in the model in the form of 4 offshore zones. Assumptions reflect average numbers assessed within empirical analyses based on data for selected European countries i.e. the same assumptions apply for all investigated countries.

Grid reinforcement costs

The level of grid reinforcement costs related to future wind installations is determined by the location of wind farms relative to load centres and existing power plants and the capacity of existing transmission and distribution grids. For countries, for which detailed grid integration studies are available, the cost scenario was selected based on study results. For other countries the selection bases on an expert guess taking into account the aforementioned relations.

Balancing costs

The selection of the balancing cost scenario bases on a flexibility indicator which has been assessed for all investigated countries[26]. The applied methodology compares available flexibility resources with current flexibility needs. The residual flexibility, the so called Net Flexibility Resource (NFR) results from the difference between flexibility resources and needs and is expressed as a share of system peak demand for the reason of comparability. In order to describe the ability of a system to dynamically respond to both power shortages and excess of power the NFR is assessed in terms of both upward and downward flexibility. Flexibility resources are determined by the power generation mix (each power generation technology is characterised by a certain degree of flexibility) and capacities of interconnectors to neighbouring countries. The latter is reflected in terms of Net Transfer Capacities published by UCTE. The demand for flexibility is determined by uncertainty and variability of load and current levels of wind power. For a more detailed description of the NFR approach see IEA (2008).

A rough characterisation distinguishes between low (NFR < 20%), medium (20% < NFR < 40 %) and high flexibility (> 40 %). The selection of the balancing cost scenario follows this characterisation i.e. for a highly flexible power system balancing costs are assumed to be low etc.

System capacity costs

Different wind power and system characteristics are reflected in the model in terms of three capacity credit scenarios (high, medium, low). The basis for the scenario selection is the geographic distribution of wind sites. For countries where wind sites are geographically dispersed the capacity credit is assumed to be high, while for countries with geographically concentrated wind power resources the low scenario is selected. The degree of geographic dispersion has been investigated for each country based on available literature on wind resource assessments.

The following table summarises selected cost scenarios for grid reinforcement, balancing and system capacity based on above described criteria for EU-27 countries.

[26] This assessment was carried out within a project on behalf of the German Federal Ministry of Environment. Results of this study are not public.

Table 5.2: Overview on selected cost scenarios for EU-27 Member States.

	Grid reinforcement	**Balancing**	**System capacity**
Austria	Average	Low	High
Belgium	Average	High	High
Denmark	Low	Low	High
Finland	Average	Average	Average
France	Average	High	Low
Germany	High	High	High
Greece	Average	Average	High
Ireland	Low	Average	High
Italy	High	Average	Average
Luxembourg	Average	Low	High
Netherlands	Average	Average	High
Portugal	Average	Low	Average
Spain	Average	Average	Low
Sweden	High	Low	Low
United Kingdom	High	High	Low
Cyprus	Average	High	High
Czech Republic	Average	Average	High
Estonia	Average	Low	High
Hungary	Average	Average	High
Latvia	Average	Low	High
Lithuania	Average	Low	High
Malta	Average	High	High
Poland	Average	High	Average
Slovakia	Average	Low	High
Slovenia	Average	Average	High
Bulgaria	Average	High	High
Romania	Average	Average	High

5.6.2 Cost allocation scenario selection

The Green*Net*-Europe model can simulate the whole bandwidth of cost allocation policies ("deep" versus "shallow" versus "super-shallow") i.e. each integration cost component can either be allocated to the producer or the end user. This way the sensitivity of wind power deployment on the pure economic effects of cost allocation approaches is analysed.

In principle, there are two options for allocating costs related to the integration of power technologies: Either the producer directly bears these costs or a third party bears the costs and further distributes these to the end user. The comparison of cost allocation practises in EU-27 countries shows a heterogeneous picture.

Grid connection costs

Grid connection costs are in general allocated to the producer i.e. the grid connection is interpreted as part of the development. The corresponding regulation for wind onshore in Hungary and treatment of offshore connection in Germany and Denmark are exemptions from this common practise.

Grid reinforcement costs

The allocation practises in place for costs related to reinforcements of the existing grid is heterogeneous. In few countries strict shallow grid connection charging is implemented, which means, that costs related to any other measure in the grid than the connection of the development itself, are borne by the grid operator. Most countries apply a shallowish approach where the producer has to partly bear grid reinforcement costs. In other countries, deep charging is applied, meaning that the producer pays all costs for grid infrastructure necessary to connect the power plant to the existing grid.

Balancing costs

The allocation of balancing costs depends on the specific support scheme. Under feed-in tariff schemes in general a third party is responsible for balancing wind power and passes on corresponding costs to consumers (cf. Obersteiner et al. (2009)). Under quota systems based on Tradable Green Certificates or Feed-In Premium schemes wind power is fully integrated into the power market and consequently also balancing responsible. This means that generation schedules based on forecasts have to be submitted to the imbalance clearing institution and deviations from schedules are charged ex post within the process of imbalance clearing.

System capacity costs

System capacity costs cannot be charged to a specific stakeholder under current market designs. These costs reflect additional capacity requirements in a system with wind compared to a reference system without and can be assessed in theory but cannot be observed as such in the power market. As a growing wind power share affects investment decisions in conventional capacities, these costs will finally be reflected in the power price i.e. the end user will bear these costs in any case.

Table 5.3 summarises assumptions for cost allocation for all integration cost categories for EU-27 Member States based on the current cost allocation practise on country level (status beginning of 2009).

Table 5.3: Overview on cost allocation settings used for the simulations (Business As Usual grid integration case – BAU grid integration).

	Grid connection	Grid reinforcement	Balancing	System capacity
Austria	Producer	Producer	End user	End user
Belgium	Producer	End user	Producer	End user
Denmark	Producer[1)]	End user	Producer	End user
Finland	Producer	Producer	End user	End user
France	Producer	Producer	End user	End user
Germany	Producer[1)]	End user	End user	End user
Greece	Producer	End user	End user	End user
Ireland	Producer	Producer	End user	End user
Italy	Producer	Producer	Producer	End user
Luxembourg	Producer	Producer	End user	End user
Netherlands	Producer	Producer	Producer	End user
Portugal	Producer	Producer	End user	End user
Spain	Producer	Producer	Producer	End user
Sweden	Producer	Producer	Producer	End user
United Kingdom	Producer	Producer	Producer	End user
Cyprus	Producer	End user	End user	End user
Czech Republic	Producer	Producer	Producer	End user
Estonia	Producer	End user	Producer	End user
Hungary	End user	End user	Producer	End user
Latvia	Producer	Producer	End user	End user
Lithuania	Producer	Producer	End user	End user
Malta	Producer	End user	End user	End user
Poland	Producer	Producer	Producer	End user
Slovakia	Producer	Producer	End user	End user
Slovenia	Producer	End user	Producer	End user
Bulgaria	Producer	End user	End user	End user
Romania	Producer	Producer	Producer	End user

Source: http://res-legal.eu/en.html (visited March 2009), own investigations

[1)] Costs for connecting offshore wind are borne by the TSO and passed on to the end user.

Note: In countries with shallowish charging it is assumed that all costs are borne by the producer i.e. deep charging is reflected in the model

5.7 Simulation results

This chapter summarizes and discusses results for selected grid integration scenarios simulated with the Green*Net*-Europe model. Core results include the deployment of several RES-E technologies up to 2020 and corresponding disaggregated grid integration costs. While the current version of the model covers a total of 35 countries, results in this chapter are provided on the level of EU-27 Member States.

5.7.1 Deployment of RES-E

In order to reflect a realistic bandwidth of the future RES-E deployment we investigate two deployment scenarios that are related to certain assumptions concerning the framework of RES-E support:

1. Current support policies are retained until 2020 (Business as usual scenario - BAU)
2. National support policies are improved in order to meet the 20% Renewables target in 2020 on EU-level (Strengthened National Policy scenario - SNP)

Under the assumption that both current support policies and non economic barrier levels are retained until 2020, the overall RES-E generation increases from 543 TWh in 2006 to 962 TWh in 2020. New RES-E technologies like wind power, solid biomass and biogas contribute most to this increase while the output from established technologies like hydro power and biowaste remains widely stable (see Figure 5.14 (left)).

More ambitious national policies which are in line with the 20% renewable target in 2020 (on EU-level) allow for a considerably higher increase of RES-E generation of up to 1306 TWh. Wind offshore, wind onshore and solid biomass contribute most to the additional generation potential realised in this scenario. Remarkable is also the increased utilisation of solar thermal electricity and PV which is almost three times higher in 2020 than in the BAU scenario. In the SNP scenario wind power becomes the dominant RES-E technology in 2020 with a share of 40 % on overall RES-E generation (see Figure 5.14 (right)).

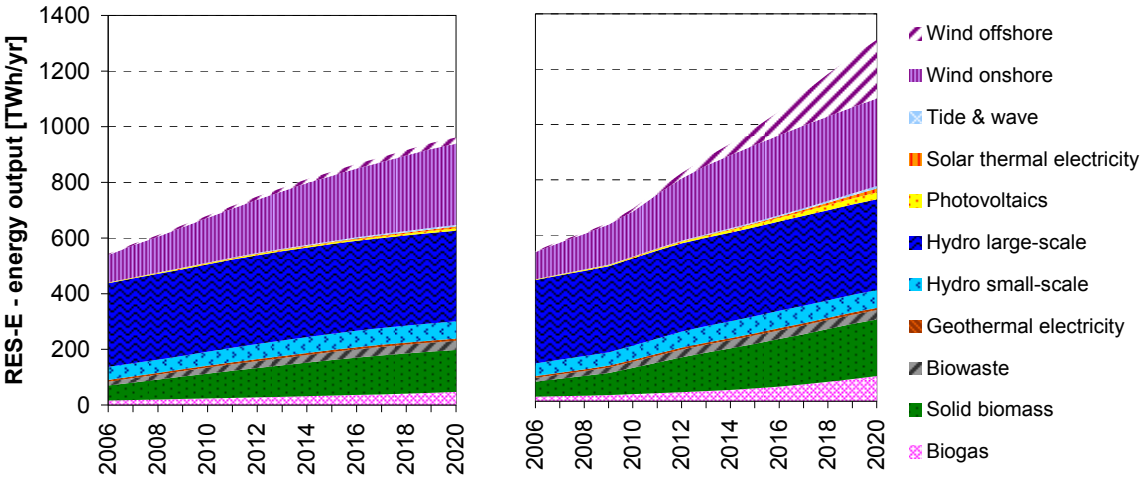

Figure 5.14: EU-27 - Annual RES-E generation potential up to 2020 for BAU (left) and SNP scenario (right).

5.7.2 Integration cost components

In the following, results for grid integration costs of wind power related to the above deployment scenarios are illustrated. Figure 5.15 draws specific disaggregated integration costs for both the BAU (left) and the SNP scenario (right).

Specific costs (per MWh wind generation) increase for all cost components over time i.e. with increasing wind penetration. This trend can be observed in grid integration studies for costs related to grid reinforcements and wind power balancing. System capacity costs increase due to a decrease in capacity contribution – the capacity credit of wind power decreases with increasing wind penetration. The development of grid connection costs is mainly determined by the share of offshore wind whose connection is more cost intensive and the development of the capacity factor of onshore wind (least cost potentials with high capacity factor are in general utilised first). These characteristics explain also higher specific costs in the SNP scenario compared to BAU wind deployment.

The dominant cost component are grid connection costs ranging from 4 to 5 €/MWh (BAU) and 4 to 8.5 €/MWh (SNP) respectively. System capacity costs are in the range of 2 to 3 €/MWh in the BAU scenario and reach up to 4.5 €/MWh in the case of strengthened national policies. Balancing costs lie between 1.5 and 2.5 €/MWh under BAU development and increase up to 3.5 €/MWh in the SNP scenario. Grid reinforcement costs are minor with up to 1.5 (BAU) and 3 €/MWh (SNP) respectively. Overall integration costs reach up to 11.7 €/MWh in the BAU scenario and 19.2 €/MWh under strengthened national policies.

These numbers are averages on EU-27 level. In Member States specific integration costs may deviate considerably depending on the specific wind share as well as system and wind characteristics.

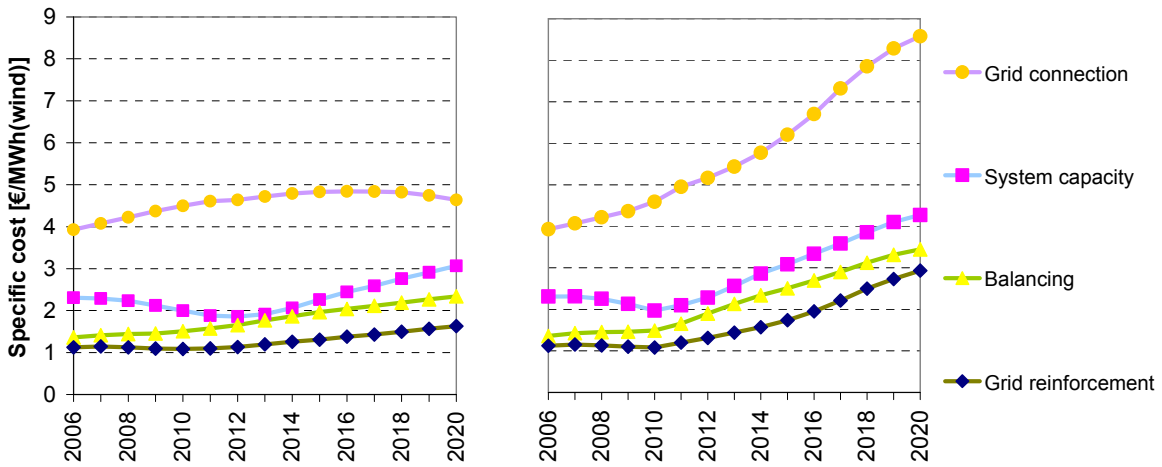

Figure 5.15: EU-27 – Specific grid integration costs of wind power up to 2020 for deployment according to the BAU (left) and the SNP scenario (right).

5.7.3 Effects of cost allocation

The following graphs illustrate how these assumptions for the allocation of integration costs of wind power drawn in Table 5.2 and Table 5.3 are translated into annual integration costs allocated to producers and end users respectively in the BAU support scenario. Balancing costs are expressed as annual costs while other cost elements reflect cumulated annuities of corresponding investments.

In EU-27 Member States grid connection costs increase from 79 M€/yr in 2006 up to 1200 M€/yr in 2020 (see Figure 5.16). A large part of these costs is borne by the producers given that connection costs are in general treated as part of the investment. The small share of costs allocated to end users mainly reflects the connection of offshore wind farms in Denmark and Germany.

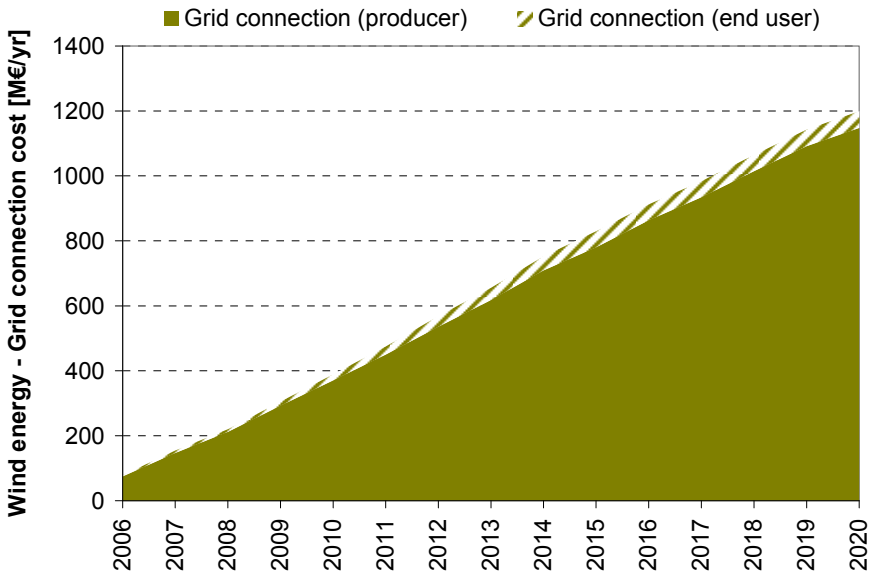

Figure 5.16: BAU support scenario, EU27 – Cumulated annuities of wind power related grid connection costs up to 2020.

Grid reinforcement costs increase from 23 M€/yr in 2006 to 422 M€/yr in 2020. More than two thirds of overall costs are borne by producers. This picture reflects the current cost allocation practise: only in 10 of 27 countries strict shallow grid connection charging is in place (see Figure 5.17)[27]. Over the last years a trend towards strict shallow charging can be observed.

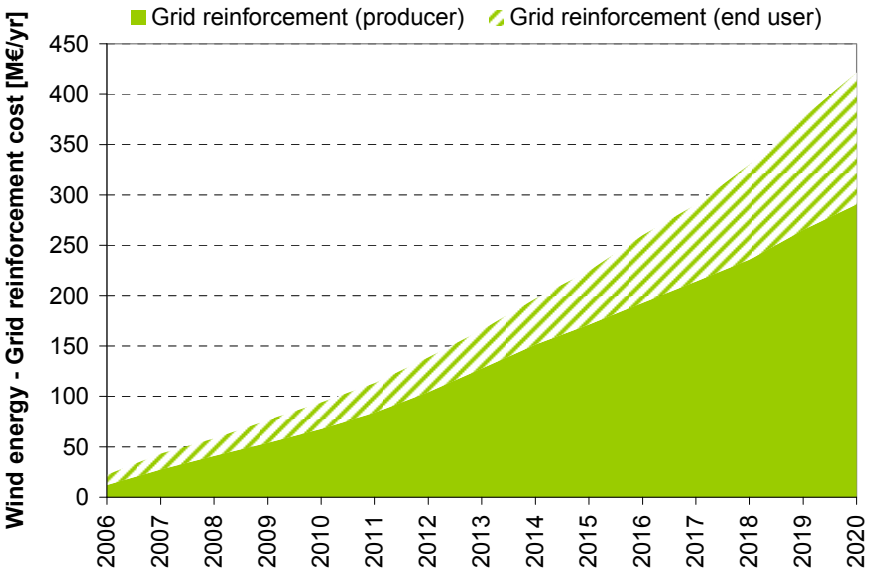

Figure 5.17: BAU support scenario, EU27 – Cumulated annuities of wind power related grid reinforcement costs up to 2020.

In the BAU support scenario annual balancing costs of wind power increase from 27 M€ in 2006 to 605 M€ in 2020. According to the current cost allocation policy balancing costs are equally shared between producers and end users in the EU-27 Member States (see Figure 5.18). There is, however, a trend towards market linked support schemes which will lead to an increased share of costs allocated to wind power producers in the future.

[27] Please note that the share of costs allocated to producers might be overestimated as for countries with a shallowish approach the model allocates all and not only part of the costs to producers.

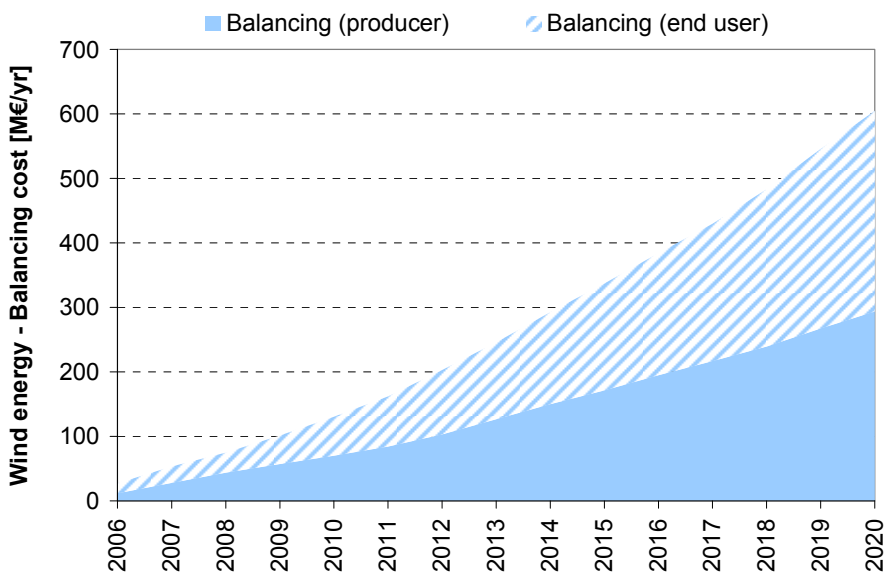

Figure 5.18: BAU support scenario, EU27 – Annual costs for balancing wind power up to 2020.

System capacity costs increase from 47 M€/yr in 2006 to 794 M€/yr in 2020. As mentioned above, these costs are in any case socialised when power markets are designed as pure energy markets and do not reflect the value of capacity (see Figure 5.19).

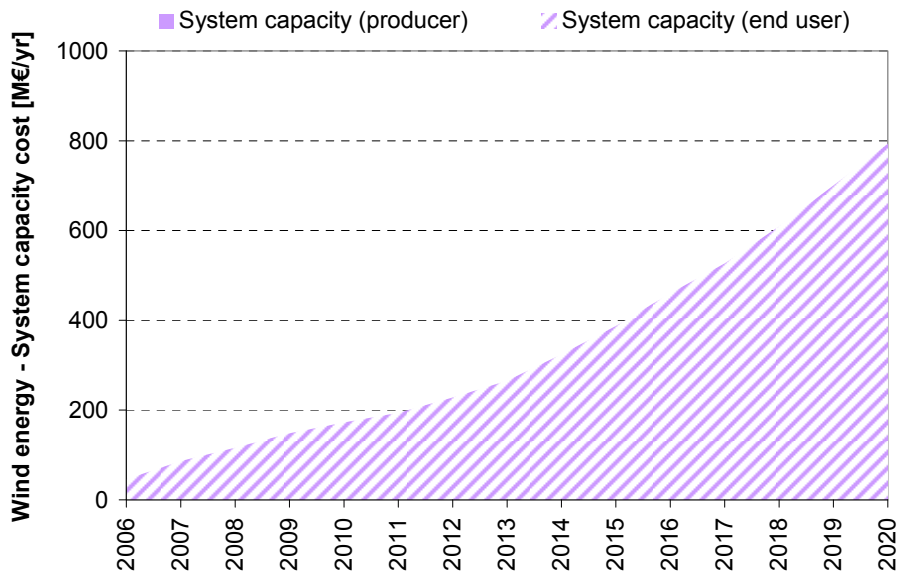

Figure 5.19: BAU support scenario, EU27 – Cumulated annuities of wind power related system capacity costs up to 2020.

To illustrate the sensitivity of wind power deployment on the cost allocation policy we simulate for both support scenarios three grid integration cases:

1. Cost allocation policies as currently implemented on country level (BAU grid integration)
2. All cost components are allocated to end users (shallow grid integration)
3. All cost components except from system capacity costs are allocated to wind power producers (deep grid integration)

Figure 5.20 compares the development of new wind power installations for these grid integration cases. The sensitivity of deployment on the pure economic effects of cost allocation policies is moderate. For the BAU support scenario deployment is comparable for deep charging and BAU cost allocation. Shallow charging results in an additional generation of 19 TWh in 2020 which is about 7% of total generation from new wind power installations. Under strengthened national policies the absolute effect of cost allocation is higher. Deep charging results in 26 TWh less wind power generation in 2020 while for the shallow case an increase of 41 TWh can be observed compared to BAU cost allocation. The overall effect of cost allocation on generation from new wind power installations is below 15 % of total generation from new plants when comparing the two extreme cases – deep and shallow charging.

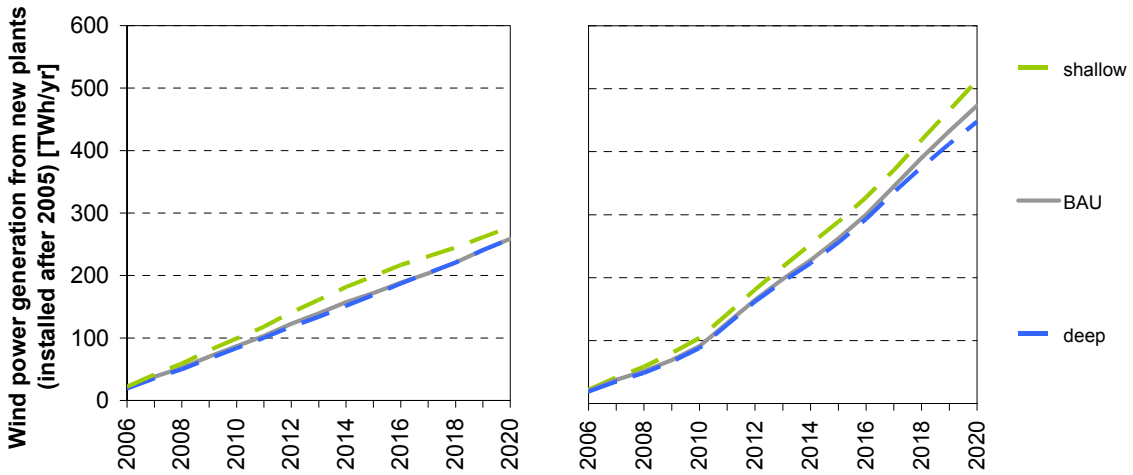

Figure 5.20: EU27 – Annual generation of wind power installed after 2005 depending on the cost allocation policy for BAU support (left) and SNP support (right).

Besides this economic aspect of cost allocation we have to expect also non-economic effects which result in a higher overall sensitivity in practice (in addition to the effects displayed in the modelling results):

It is requested that deep grid connection charges are determined on a non-discriminatory basis. At present, corresponding implemented rules are not sufficiently transparent in order that discrimination can be prevented beforehand, as e.g. bilateral contracts between generators and grid operators are not public. Lack of transparency in this context has been reported by stakeholders on various occasions in the project.

Also, it is disputable to which extent RES-E generation in general is being discriminated against conventional generation technologies in the presence of deep grid connection charges, as most beneficial RES potentials in many cases are located in remote areas to load centres, whereas e.g. fossil fuelled generation may be located centrally. Deep connection charging may also intervene with the principle of separating the responsibilities of planning, financing and operating the grid infrastructure on the one hand and electricity generation on the other hand. Coordinated planning of priority deployment regions for RES-E and according infrastructure investments by grid operators may lead to efficient deployment strategies from an economic viewpoint, if grid reinforcement and extension investments can be kept low due to a sub-additive cost function in comparison to the attribution of incremental cost elements towards single RES projects and according upgrading measures.

5.7.4 Interaction between energy efficiency and RES-E policy

The European Commission defines targets for energy from renewable sources as a share on gross final energy consumption (see Directive 2009/28/EC). Therefore, energy efficiency and renewable support policies are interdependent – improved end use energy efficiency translates into lower targets for energy from renewables in absolute terms.

Besides this policy relation energy efficiency measures also affect RES-E deployment under the assumption of a given support policy framework. Demand and RES-E generation are interlinked through quota systems that define the demand for RES-E as a share of gross electricity demand. Further, a reduction in electricity demand lowers ceteris paribus the electricity price and affects the economics of RES-E if support schemes are linked to power markets.

We apply the Green*Net*-Europe model to investigate the dependence of RES-E generation on energy efficiency measures for a given RES-E support framework. Effects on the electricity price are not reflected as this parameter is an exogenous input to the model. The change in RES-E generation reflects purely the dependency provided through quota systems.

Figure 5.21 draws gross electricity demand and RES-E generation for both investigated support scenarios. The efficiency scenario reflects a framework where the end user has perfect information, does not face transaction costs and acts economically rational. Under these assumptions it turns out that most of modelled energy efficiency potentials are realised without any additional incentives. This implies a significant reduction of demand by 849 TWh in 2020 which is 21 % of the corresponding reference demand.

The resulting reduction in RES-E generation is moderate in both support scenarios with 1.5 (BAU) and 2 % (SNP) of reference generation in 2020 respectively. The absolute reduction in generation amounts to 15 (BAU) and 26 TWh (SNP) respectively. This result reflects the fact that quota systems are in place in few EU Member States only (see Ragwitz et al. (2007)). A large share of RES-E is supported via price driven instruments like feed-in tariffs or feed-in premium schemes.

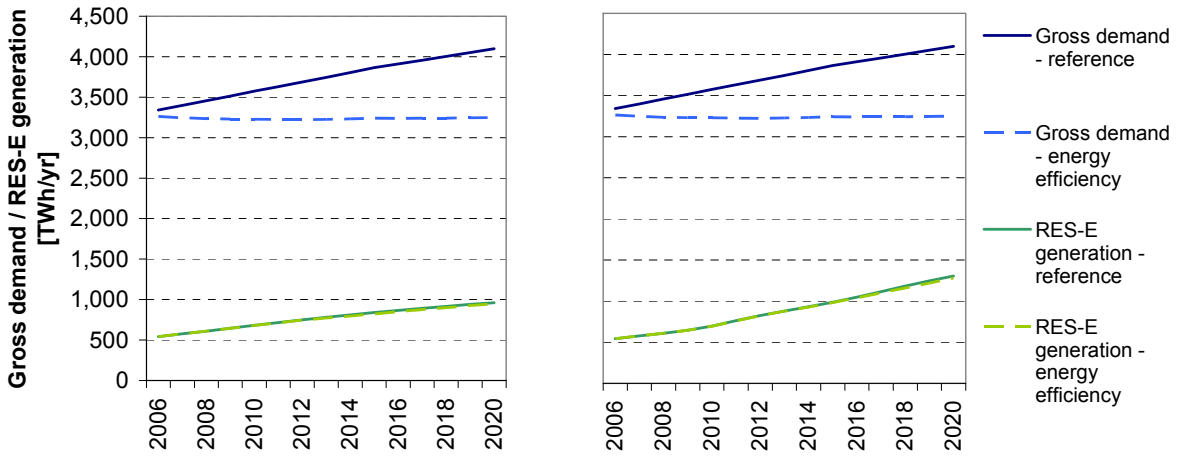

Figure 5.21: EU27 – Effects of an improved end use energy efficiency on gross demand and RES-E generation for BAU support (left) and SNP support (right).

6 Recommendations for key stakeholders

In the following sections, most relevant recommendations for the key stakeholders involved into the policy design, regulation and realisation of large scale RES-E grid and system integration are summarized:

These recommendations have been derived from theoretical and applied analyses of implemented grid regulation mechanisms, a consultation of stakeholders and experts' opinion as communicated in the course of different events (expert discussion platforms, workshops, dissemination events).

Electricity market regulations have dynamically evolved over time within national boundaries, taking into account national peculiarities of resources, topology, industry structure and (energy) policy. Therefore – despite of partly successful efforts to harmonise European electricity markets – a broad variety of currently implemented regulations is still in place in different European countries. Accordingly, many topics, which also in the course of various expert meetings organised in the Green*Net*-Incentives project have been discussed highly controversially, have been subject to amendments in the past years and will be adapted also in the coming years. On the background of this dynamic context, country specific – and potentially already outdated – recommendations derived in the course of the Green*Net*-Incentives stakeholder consultation, the evaluation of regulatory practices etc. shall not be replicated here. From this viewpoint, the following recommendations do have different relevance for different countries. Whereas they may have been derived from "best practise" implementations from some countries, they may not be considered in other countries at all. The stakeholder consultation (see chapter 3) has shown, that also the viewpoints of regulatory authorities, grid operators and RES-E developers / investors are strongly diverging both between these groups (even within single countries) as well as between countries.

One common feature of all stated recommendations is the conclusion, that nationally specified laws, regulations, procedures and practices have to be streamlined in a way to support the goals of agreed and effective European (renewable) energy policy, a factor, which seems to be considered only partly until so far.

6.1 Grid Operators

Even though grid operators fulfil a crucial role in the success of RES-E promotion, they are attributed a minor role in the design process of RES-E policies. However, associations of grid operators are usually being consulted in the preparation of national legislation and regulatory mechanisms. As regulated enterprises their economic incentives for dedicated RES-E investments have to be defined by policy makers and regulatory authorities. On the background of European renewable energy policy grid operators will in the medium to long term necessarily have to technically enable the deployment of RES-E technologies in large scale and from this perspective it seems advantageous that this stakeholder group takes on a supportive role towards the integration of renewables focussing on the precondition, that additional efforts on their side need to be compensated.

Following recommendations are targeted towards grid operators:

- Through active involvement in the decision making process of renewable energy legislation, infrastructure planning and energy regulation, grid operators and their associations on national and international level can bring in their expertise on the topic of RES-E grid and system integration and communicate the measures, which will enable them to support the reaching of national and international renewable energy policy goals.

- Grid operators shall aim at highest transparency in the procedure of granting grid access to generators: Respective cost allocation methodologies and detailed mechanisms of determining disaggregated cost components as well as on the provision of ancillary services shall be publically available to all interested parties (comprehensive regulatory framework available in English translation on the website of grid operators and regulatory authorities). The provision of this information facilitates the improvement of implemented regulation and encourages international competition between prospective project developers.

  This transparency with respect to different RES-E integration cost categories also raises public and political awareness that these costs also need to be considered – i.e. clearly attributed and reimbursed – in the design of renewable energy policies.

- The evaluation of the feasibility to connect a certain generation capacity (or load) to a distinct access point (including potentially necessary infrastructure enhancements) shall be provided on a verifiable basis by the grid operator or independent organisations.

6.2 Regulatory Authorities

Energy regulatory authorities play a significant role in the enhancement of the investment framework for RES-E installations. While regulatory bodies act on the basis of national and international legislation and therefore are facing a stringent framework for their operation, their level of activity and engagement heavily influences the interplay between grid operators, generators and consumers.

Following actions are recommended for this group:

Grid regulation:

- In the elaboration of the terms of grid access and the determination of use of system charges, the aspect of cost allocation for RES-E integration and respective reimbursement mechanisms shall be treated separately, as European legislation allows for the positive discrimination of RES-E generation.

  When incentive regulation schemes are applied, adaptive ex ante mechanisms reflecting potential extra costs due to RES-E integration need to be implemented into the principal formal framework in a way that additional costs faced by grid operators do not cut their profits but can be reimbursed via grid tariffs: Costs, related to the integration of RES-E, need to be exempted from incentive mechanisms, which impose cost-efficiency improvements on regulated grid operators. Recovery of these costs shall be guaranteed via pass-through into use of system charges.

  Complementary regulations need to be put in place ensuring cost efficiency with this respect. Adaptivity in this context shall only be related to future activities, taking account of technological learning and economies of scale, but keeping the framework of cost recovery stable for sunk investments.

- In the formulation of the principle regulatory mechanism (including adaptations for RES-E related costs) the applied approach needs to be easily understandable and intuitive to all market participants.

- Incentives for investments into the transmission as well as distribution grid dedicated to the integration of renewable energy sources shall be evaluated on national level against the background of European legislation on a regular basis. A resulting progress report can be utilised for potentially necessary improvements of the incentive scheme in place.

Unbundling and definition of system boundaries:

- Safeguarding the compliance of grid operators and utilities with the basic unbundling principles provides a necessary precondition for successful entrepreneurial activities of RES-E generators.
- The establishment of common connection boundaries to the grid infrastructure, both on the generation and demand side, sustains transparency in the process of obtaining grid access and supports the principle of unbundling in terms of clearly separating responsibilities between competitive and non-competitive segments of the electricity industry.

Use of system charges and locational signals:

- Shallow charging of grid integration costs for RES-E generator can support the cost efficient deployment of renewable potentials, as long as locational signals, which are reflecting the economics of grid enhancements, constitute a significant criterion for the siting of plants.
- Locational signals shall be implemented in an ex-ante approach in order to dynamically limit RES deployment to economically feasible potentials or such sources, which are politically desirable to be deployed (e.g. wind offshore). Additionally, location dependent use of system charges are suited to provide an economic trade-off for generators between favourable potentials and infrastructure costs without increasing overall support costs.
- Locational signals in the form of location dependent use of system charges – having to be paid by generators – need to be related to electricity production (€/kWh) or rated capacity for a certain period (€/kW_{RES}/yr) in order to prevent the establishment of financial barriers for project developers in terms of high upfront investment costs. Charging long run incremental costs to generators applying for grid access in a specific region rather than the costs of discrete upgrades to individual project developers avoids problems associated with first movers and free-riding.
- Super-shallow charging of integration costs of offshore wind farms facilitates financing of these highly capital intensive projects and bears the potential to decrease the overall costs of connection, as capital costs faced by grid operators are supposed to be lower in comparison, while the investment horizon/depreciation time is longer. Super shallow charging promotes the realisation of cost efficient joint (versus strictly individual) connections of projects, which are located remote to existing grid infrastructure.
- (Super)-shallow charging bears the potential to lower the producer surplus in case of diverging integration costs, which are positively correlated with pure long run electricity production costs. For this reason, overall transfer costs for consumers for the support of RES-E can be lowered, or the volume of supported production increased under a constant support volume. Again, the implementation of location signals is necessary to maintain overall economic efficiency.

General:

- European Energy Regulators (CEER&ERGEG) shall facilitate and support the harmonisation of national provisions for the access to and usage of the electricity grid infrastructure. Such efforts could result in a stepwise implementation of proven best practise regulation with respect to the integration of RES-E generation.
- Strategic retention of licenses for grid access needs to be impeded in order that RES-E deployment is not delayed. Implementation of binding expiry dates for grid access permits might be suitable to avoid the extraction of rents from speculation.

- Regulatory provisions for the attribution of cost components of RES-E grid and system integration need to be consistent with cost-recovery mechanisms: If a party is attributed certain costs, according reimbursement mechanisms need to be put in place in order to avoid reluctance in the deployment of renewable energy sources.
- Regulatory authorities shall aim at simplifying, standardising and accelerating procedures, which are necessary to obtain the status of eligible RES-E generators.

6.3 RES-E Developers / Investors / Industry Associations

RES-E developers and investors are eventually delivering the progress towards meeting renewable energy policy goals (together with consumers). Their economic environment is determined not only by promotion instruments for RES-E generation but also by the conditions in place for utilising the electricity grid infrastructure.

RES-E developers, investors and industry associations can positively influence the decision making process of policy makers. Respective targets include:

- Highest efforts need to be dedicated to their core competences (project development, realisation and operation). Therefore, a clear separation of responsibilities from the core competences of grid operators is regarded essential.
- Historically, RES-E developers and grid operators have often taken on opposing roles in their aim to improve their respective economic framework conditions. In the case of recovery mechanisms for costs, which arise to grid operators from integrating RES-E generation, an improvement from the viewpoint of grid operators is seen as beneficial also for RES-E developers.
- These stakeholder groups can contribute to increasing transparency in the provisions for grid access and grid utilisation by grid operators. Associations may gather and disseminate respective information on economic determinants.
- Industry associations can on this basis exert influence on policy makers with the goal of implementing proven best practise regulations observed in other countries.
- If certain technical standards and provisions, which are improving the integration of RES-E generation technologies into power systems/electricity grids in terms of security of operation are being offered/ordered as standard equipment, respective sources of scepticisms/reluctance, which have been historically utilised as arguments against the deployment of RES technologies, can be eventually removed (e.g. fault-ride-through capability of wind turbines; power quality issues).

  As a result, also in countries, where less demanding grid codes are in effect, technology will be installed, which is best compatible with grid stability from the start.

6.4 Policy makers

Policy makers are determining the economic framework for the development of renewable energies on international and national level. Respective legislation is the key determinant for the success in meeting policy goals. This legislation not only needs to incentivise the utilisation of different renewable sources via promotion instruments but also to establish favourable economic conditions for regulated grid operators: Economic provisions need to be established, which are suitable to motivate grid operators to invest into transmission and distribution grids for the dedicated objective of efficiently integrating renewable energy sources:

Following actions are recommended for this group:

Renewable energy policy:

- On the background of existing European renewable energy policy and according RES-E targets policy makers need to develop a long term strategy determining
  - which renewable sources shall be deployed
  - to what extent these sources shall be deployed
  - in which timeframe they shall be deployed
  - in which regions different potentials shall be preferentially deployed.
- On this basis, efficient criteria for the remuneration of costs arising from grid integration of these sources need to be established.
- Spatial planning needs to allow for the deployment of renewable sources according to the objectives set by energy policy.
- Research and development expenditures of grid operators need to be incentivised, in order to trigger technological progress and learning with respect to integrating (volatile, dispersed, remote) electricity production from renewable sources. Public (co-)funding of respective research shall be excluded from overall revenue restrictions of grid operators (e.g. for equipment and personnel cost for research).
- Renewable energy policies and according support schemes need to unambiguously define the responsibilities of grid operators and generators with respect to the costs, efforts and timeframes of grid integration measures (connections, reinforcements). According financial burdens need to be considered in terms of reimbursement mechanisms either in the regulatory provisions for grid operators or the level of financial support for generators.

Economic framework of grid operators:

- The introduction of an inherent mechanism in the regulation of grid operators to incentivise investments for efficient integration of RES-E generation is seen as a key success factor of meeting ambitious goals for the deployment of renewable energy sources.
- So called incentive regulation schemes need to be adapted in order that grid operators are being reimbursed additional costs arising from the integration of RES-E generation.
- Long investment cycles of electricity grid infrastructures and high capital intensity need to be reflected in the design of a forward looking investment environment for grid operators. These factors necessitate long-term stability of cost recovery mechanisms for infrastructure investments.

Grid integration:

- When grid connection is becoming a decisive cost component in the utilisation of sources, as is the case for e.g. offshore wind energy, there is evidence from historical observation, that planning, installation and operation of respective transmission infrastructures needs to be put in the responsibility of grid operators in order to initiate the realisation of projects.
- Shallow and super shallow grid integration approaches for RES-E in an environment of support policies can lead to lower transfer costs for electricity consumers, when overall economic efficiency is maintained via locational signals.

Administrative procedures:

- Administrative procedures for the connection of micro-scale generation (< 30kW) can be kept to a minimum (installation by certified personnel and notification of the grid operator), as implemented regulations show. This policy activates private willingness to pay and will become increasingly important, as soon as micro scale RES-E generation technologies are approaching "grid parity".
- In order to speed up the deployment of RES-E, standardisation, simplification and acceleration of procedures, which are necessary to obtain the status of acknowledged generators, have been identified as high priority tasks for policy makers in several countries.
- Currently, grid enhancements are often delayed by lengthy administrative procedures. In order to facilitate investments into grid infrastructure, administrative burdens need to be reduced and according procedures accelerated.

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