REGULATORY ROAD MAPS FOR LARGE-SCALE INTEGRATION OF ELECTRICITY FROM INTERMITTENT RESOURCES IN FIVE NATIONAL ELECTRICITY SYSTEMS[1]

by

Adriaan VAN DER WELLE[a,*], Jeroen DE JOODE [a,b], Frits VAN OOSTVOORN[a]

[a] Policy Studies Unit, Energy research Centre of the Netherlands (ECN), the Netherlands
[b] Faculty of Technology, Policy and Management, Delft University of Technology, the Netherlands

Key words: electricity systems, intermittent generation, RES-E/DG integration, power markets, networks, regulatory road maps

Abstract

The envisaged increase of electricity generation from intermittent renewable energy sources (RES-E) will increase system integration costs considerably. As a result, European targets for 2020 are not likely to be achieved in case no system cost reducing measures are taken. Therefore, based on an earlier analysis of a wide range of technical and institutional cost reducing options, this paper places the options in road map perspective for timely consideration and implementation of the most important options by national and European policymakers and other stakeholders.

1 Introduction

The European Commission, in agreement with the member states, has formulated clear and ambitious targets for enhancing the energy market sustainability in 2020, i.e. 20% of final energy demand should be supplied by renewable energy, and both a reduction of 20% of CO_2 emission and 20% energy savings have to be achieved.

Particularly the first goal implies that electricity generation from renewable energy sources (RES-E) has to increase to about 35% since the contribution of other sectors like heating and cooling to this goal is envisaged to be lower. This is generally perceived as an ambitious target, especially in those member states with a limited availability of hydro and biomass. In the latter a large penetration of RES-E from wind, photovoltaics (PV) and heat-led combined heat and power (CHP) is essential for achieving the EU RES targets for each member state. These sources are considered to be of ‘intermittent’ nature, since they are either weather driven (wind and PV) which makes electricity output more variable and less predictable, or show a less controllable electricity output (heat-driven CHP) than other generation technologies.

An increase of intermittent generation has profound implications for the power system as a whole, for two reasons. Firstly, power flows in *networks* will become more variable as well as a result of the increase of generation variability. Besides, more power will be fed-in the grid at lower voltage levels (‘distribution grid’), sometimes exceeding demand and implying upward flows to

---

[1] This paper is based on the research project RESPOND (www.project-respond.eu) which aimed at providing policy makers with optimal regulatory actions to be implemented in order to achieve a cost-efficient integration of intermittent generation in power systems in the period until 2020. This project was supported by the IEE programme of the European Commission. The sole responsibility for the content of this document lies with the authors. It does not represent the opinion of the Community. The European Commission is not responsible for any use that may be made of the information contained therein.

[*] Contact details: A. Van der Welle, Radarweg 60, 1043 NT Amsterdam, the Netherlands; +31 (0)224 – 564496 (phone); +31 (0)224 – 56 8339 (fax); vanderwelle@ecn.nl (e-mail).

higher voltage levels ('transmission grids') for transportation of electricity to other load centres. Secondly, when the penetration reaches substantial levels, the intermittent power supply implies also an increase in the balancing of supply and demand, and changes of *market* prices during times with and without wind energy[2].

Both effects result in higher system costs, which impede the fast integration of the envisaged large amounts of RES-E in the power system in case no system cost reducing measures are taken. For this reason, this paper analyses a wide range of cost reducing options. Since the RES-E share develops gradually, the number of available options is high and consequently some options are more required than others, a prioritisation of options is required. Therefore, options have been classified with the roadmap methodology for assisting policy makers to lower the system integration costs of intermittent renewables in the most cost-efficient way in time.

Since power systems and their concomitant costs vary widely according to different system characteristics like generation mix, penetration level of RES, location of RES and demand, network topology and operation, and market design applied, regulatory roadmaps have been developed for five countries. In this paper this approach is illustrated for two countries; Denmark and Germany. These countries are selected since they are among the countries with the highest RES-E penetration in Europe.

The structure of the report is as follows. Section 2 outlines the background for our analysis; the gap between current and foreseen penetration of RES-E and the need for additional system flexibility to accommodate impacts of increasing generation from intermittent RES-E. In section 3 we present our regulatory road map methodology. Section 4 applies this methodology to Denmark and Germany. Section 5 concludes and provides the most important policy recommendations and actions for different stakeholders, as well as suggestions for further research.

2 Background

2.1 Increasing penetration of intermittent generation

For achieving the renewable energy targets of the EC, all European countries are committed to strive for a higher penetration of renewables in final energy consumption. The figure below clearly shows the large gap between the current and EC proposed energy share from renewable source for most EU member states. The majority of member states, 16 of 27 countries, have to double their renewable energy share in final energy consumption. A large part of this new renewable energy is assumed to stem from new renewable electricity production. Since intermittent RES is increasingly adding more capacity than energy production to the system, the capacity credit decreases and renewable electricity needs to increase even more in production capacity terms in EU and its member states to reach the target in 2020.

[2] Since electricity originating from wind generation is by far the most important intermittent production technology, we focus mainly on the description of the impacts of and solutions for the increase of wind generation.

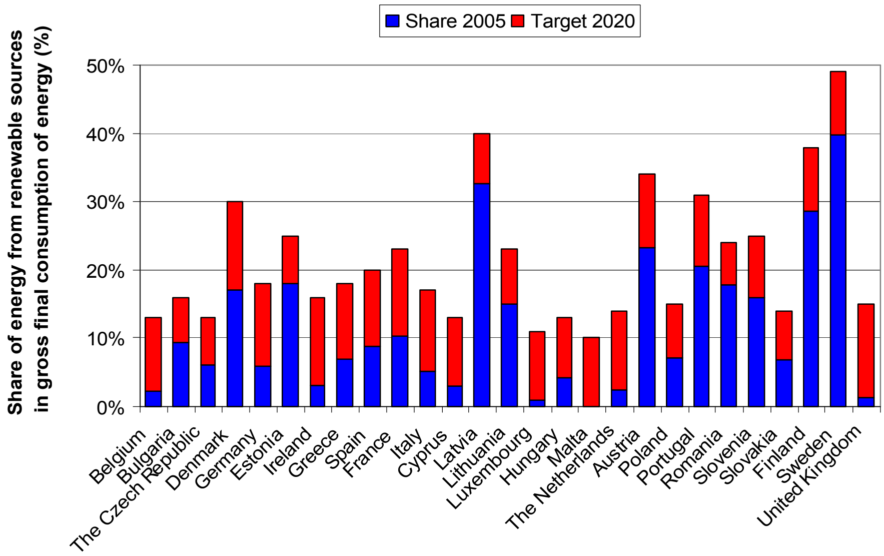

Figure 2.1 *Share of energy from renewable sources in gross final consumption of energy in 2005 and EC target for 2020 (Data obtained from EC, 2009)*

2.2 Impact of intermittent generation on electricity systems

Adding more intermittent generation to the system has implications for different power system segments: generation, balancing and wholesale markets, and transmission and distribution networks.

Impact on **generation** is caused by the fact that RES substitute energy and capacity of conventional power plants. Substitution of energy leads, apart from positive impacts, such as reduction of fossil fuels consumption and associated CO_2 emissions, either to part-load operation of power plants or to the increased cycling of their start-up and shutdown. Both outcomes bring about higher costs and emissions. Substitution of capacity decreases the conventional generation required to cover annual peak demand. Different RES and DG technologies will be able to displace different amounts of capacity, but generally RES displaces more energy than capacity of conventional generation due to the higher variability and lower predictability of its production. Consequently, flexible generators with high ramping capabilities (gas-fired and hydro based generators) have to be available for critical system times (like high demand, low intermittent RES supply). On the other hand, base load conventional plants are shifted to the margins and may see a reduction in their profitability with increasing penetration of RES and DG.

Through the increase of intermittent RES-E/DG production also the need for more **balancing power** may rise. The need for frequency regulation and reserves will increase with higher penetrations of intermittent sources, making the system facing increasing balancing costs. Balancing costs consist of costs for primary, secondary and tertiary reserves. The additional cost of primary reserves or frequency regulation is considered to be small. In case wind power penetration increase with 20%, the demand for secondary reserves is expected to increase – ceteris paribus- with 3-7% of peak load or capacity in the Nordic countries (Holttinen, 2004). This percentage is highly dependent on the system under consideration, especially security of supply requirements of system operators and the balancing market design chosen. One important balancing market design issue are differences in gate closure times of power exchanges and balancing markets. Generally, the demand for secondary reserves is expected to grow with a higher percentage of peak load when wind power penetration exceeds 20-30% of gross demand. The demand for tertiary reserves will rise in the same proportion as the demand for secondary reserves.

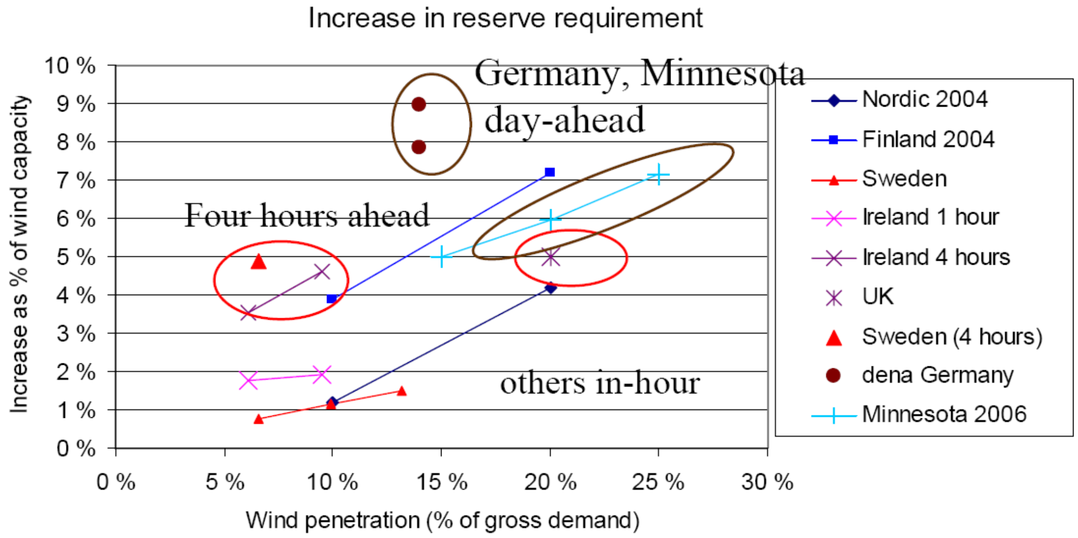

Figure 2.2 *Increase in reserve requirement with higher wind penetrations (Source: Holttinen 2007)*

Through incorporating more RES and CHP production in the system, intermittency is passed through from production to network operation which has effects on both **distribution and transmission networks**. Most intermittent RES currently is connected to distribution networks. In the short term this gives rise to voltage rise problems in rural networks and an increase of fault levels in urban networks. In longer time scales, ranging from hours to years, power flows may change as the system architecture changes considerably; with higher penetrations of DG, a large number of renewable generators are connected to all distribution voltage levels instead of mainly a small number of large generators connected to higher voltage levels. This has important consequences for the reliability and security of the electricity system as it influences both the direction and magnitude of the power flows on the network.

On the one hand, since more power is supplied to distribution levels, less power has to be transferred from the transmission level downwards in the chain to the end consumer. On the other hand, a higher penetration of DG implies that power supply from intermittent generation sometimes exceeds the local load and therefore needs to be exported to other regions. Consequently, the excess of power needs to be transferred from distribution networks to the transmission network and upward flows will occur. So while the magnitude of top-down power flows reduces, reverse power flows may occur and the direction of power flows may alternate between top-down and bottom-up. The latter is shown in the figure below.

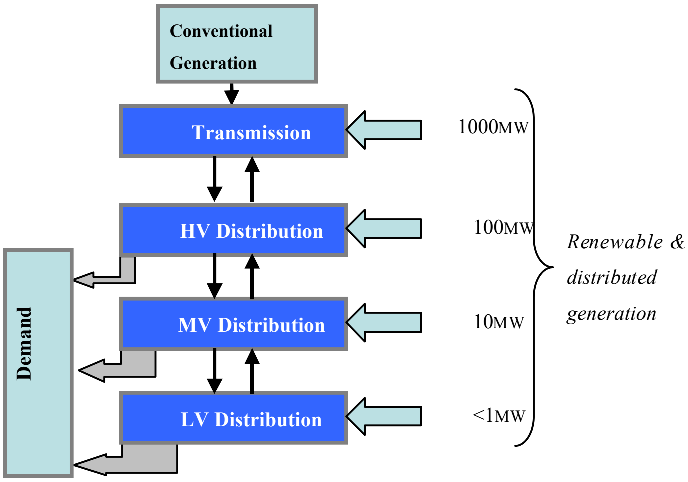

Figure 2.3 *Connection of various forms and sizes of distributed generation to distribution networks (HV: High Voltage; MV: Medium Voltage; LV: Low Voltage) (Source: adapted version of Ramsay et al. (2007), p. 12)*

As a consequence, the distribution network operator has to deal with a higher number of different and extreme situations in network flow management. Therefore more distribution network capacity is required for being able to handle those flows, especially flows originating from forms of generation which depend on the availability of natural resources, for instance wind and are therefore more variable and less predictable. This is also partly due to the 'fit and forget' network planning philosophy in distribution networks, which is primarily aimed at resolving all possible network situations through network reinforcements (transformers, overhead lines, network cables). Consequently, distribution network operators dispose of very limited steering and control possibilities of power flows in their networks, which is increasingly costly since the utilization of new network reinforcements is limited due to the high diversity of power flows.

RES-E is also increasingly connected directly to transmission networks (e.g. offshore wind parks). Besides TSOs have to deal with reverse power flows coming from (rural) distribution networks with surplus of power, which needs to be transferred to areas with shortage of power. For including these flows in the network additional network reinforcements may be needed, although to a more limited extent than in distribution networks since transmission networks are actively managed. TSOs already dispose of possibilities for real-time network control through better monitoring and control possibilities like network switching, reconfiguring, or using reactive compensators.

2.3 Conclusion – Need for more efficient electricity systems and system flexibility

Clearly, the fast growth of RES-E production in line with EU 20-20-20 goals has substantial impacts on electricity networks, system balancing and markets. Consequently, system integration costs are expected to increase strongly, endangering the fast growth of RES-E. In order to prevent such a scenario to occur, cost reducing measures to react to these cost impacts should be taken. For example, shorter gate closure times of trade markets may reduce system balancing requirements, while active network management may render distribution network capacity extensions more cost efficient. These so-called response options enhance market flexibility and/or network controllability of power systems and therefore reduce system costs and increase system flexibility.

Since power systems and their concomitant costs vary widely between EU countries according to different system characteristics, different countries need to take different actions to increase the flexibility of their respective power systems. Besides the timing of these actions may differ according to the actual development of RES-E, demand and other power system characteristics. Therefore, a country-specific roadmap is required for every country at hand for implementing in time the required measures for a cost-efficient integration of RES in its national power systems. The methodology for creating those roadmaps is explained in the next section.

3 Methodology

3.1 Introduction

The basic methodology applied in this report is that of road-map building, and more specifically building a road map for regulatory actions. The principle of road maps in general has been derived from technology road maps (Van Sambeek *et al.* 2003). A regulatory road map presents possible routes of regulatory development and indicates important intermediate points in time for a smooth transformation of the electricity system. Its basic building blocks are:

1. Overview of response options in different segments;
2. Stages of market integration;
3. Stages of network integration.

We explain these building blocks consecutively below. These culminate in the regulatory road map tool used in the construction of national regulatory road maps in section 3.5.

3.2 Overview of response options

For realizing a socially optimal integration of intermittent technologies in power systems there is a wide range of different technical and institutional options available to do so; these are called response options. Below we summarize some of the main findings from the RESPOND study. The Figure is not exhaustive and only meant for illustrative purposes.

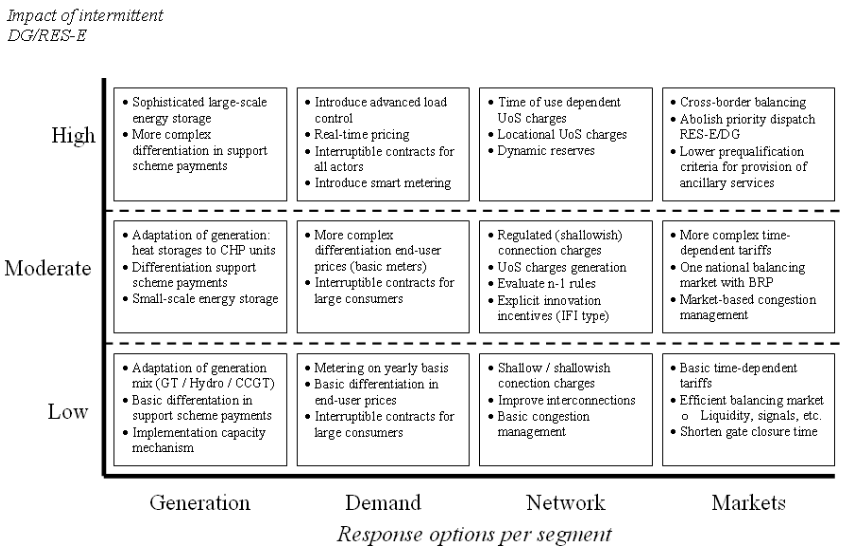

Figure 3.1 *Indicative response options per segment*

The different electricity market value chain elements used throughout the RESPOND study are listed horizontally. On the vertical axis we depicted three qualitative degrees of intermittent RES-E/DG impacts within the electricity system. The impact of RES-E/DG on the electricity system, which results from either a high absolute level of intermittent RES-E/DG or a large relative share of RES-E/DG, can be qualified as low, moderate or high. This classification should illustrate the principle that implementation of certain response options should be proportional to the problems created by more and more intermittent RES-E/DG.

The response options are required for integrating large amounts of RES-E/DG in different power systems up to 2020. For simplicity, in the remainder of this paper the response options of the different segments are attributed to either market or network integration. Consequently, the system transformation process can be described with two dimensions: market and network integration.

3.3 Stages of market integration

Market integration concerns the integration of new RES-E/DG generation units in different markets: electricity wholesale market, and the markets for system balancing and other ancillary services.

Based on earlier RESPOND research we have precisely defined three different stages for market integration. The three stages are strongly related to different penetration levels of intermittent RES-E/DG in the electricity system. The three stages respectively relate to low, moderate and high levels of RES-E/DG in the system and can be associated with various levels of negative system impacts caused by this amount of RES-E/DG as well as consistent sets of measures to overcome these system impacts. In addition, the different stages specify the role that RES-E/DG plays, either actively or passively in electricity markets in each stage. With an increase in the share of intermittent RES-E/DG, RES-E/DG generation gets to an equal level as centralized (non-intermittent) generation on the various energy markets. In the transition towards a situation with a high penetration level of RES-E/DG, providing RES-E/DG equal opportunities implies that additional incentives are realised that favour additional penetration. In the final end stage, RES-E/DG might be given an equal role to play in the different sub-markets of the electricity system (wholesale market, balancing market, and other ancillary services market), but this equal role should only be facilitated when deemed optimal from a social perspective. After all, there are particular differences between the inherent characteristics of conventional electricity generation technologies and RES-E/DG electricity generating technologies, and these differences might give rise to differential treatment of the two. Equal treatment could possibly lead to suboptimal electricity market outcomes from a society's point of view since some production technologies have more favourable characteristics than others.

For the purpose of constructing regulatory road maps each stage is accompanied by specific criteria, linking penetration levels with regulatory measures. We refer to Table 1 for an overview of the different market integration stages we distinguish.

Table 1 Stages of market integration

	Stage	Description	Criteria (market integration issues)	Recommendations
A	**Protected niche market**	• **Low penetration** level of RES-E/DG • RES-E/DG outside the markets	• Wholesale market access • Variable RES-E/DG negligible impact on markets	• Focus on economic viability RES-E/DG, priority dispatch, feed-in tariff regime
B	**RES-E/DG in the market**	• **Moderate penetration** level of RES-E/DG • RES-E/DG participates partly in supply side of ancillary services market. • RES-E/DG has little to moderate effect on market prices.	• Wholesale market access, limited access to other markets • Moderate impact in system balancing costs • Need for differentiated market prices to reflect system conditions	• Move to feed-in premium • Introduce basic interval metering • Regime of balancing responsible parties • (Regional) market-based congestion management
C	**Active RES-E/DG**	• **High penetration** level of RES-E/DG • RES-E/DG provides all kind of ancillary services when profitable • RES-E/DG has moderate to high effects on market prices	• RES-E/DG enters other markets (ancillary services, balancing) • Substantial increase in system balancing cost • Demand-side involvement in balancing and ancillary services market	• Implementation of smart metering • Facilitate interruptible contracts • RES-E/DG involvement in all markets

3.4 Stages of network integration

The two main questions to answer when defining the possible different stages of network integration of intermittent RES-E/DG are: what are the different network integration issues, and how do these issues evolve over time when the penetration of these generation units increases?

In total, five different stages of network integration have been identified. These vary from basic distribution networks with minor regulation that are operated very passively and configured towards centralized electricity generation (Stage I), to very complex and smart networks with substantial regulation that considers all short and long term costs and benefits and that are operated in a very active manner (Stage V). This phase classification is presented in Table 2.

Table 2 Stages of network integration

	Stage	Description	Criteria (network integration issues)	Recommendations
II	**Performance -based networks**	**Regulated network access**, cost-driven, incentives for efficiency improvements	• Negotiation on connection costs • Limited network reinforcements • Limited congestion due to variable RES-E/DG	• Shallow regulated connection charges (mandatory access) • Basic congestion management
III	**Enhanced performance -based networks**	Regulated network access, **incentives for efficiency**, incl. **quality** incentives & **basic innovation** aspects.	• Increasing network integration costs (especially distribution) • Differential impact across distribution networks • Increasing congestion	• Shallow regulated connection charges plus basic use of system chages • Account for differential RES-E/DG impact across networks
IV	**Innovative networks**	**Innovative distribution network** (monitoring and limited control possibilities), incentives for innovation, active transmission network	• Increasing network integration costs (upward flows) • Proper incentives for network operators and generation / load • Increasing congestion	• Basic time/location differentiated connection & use of system charges •RES-E/DG in network planning • Market-based congestion management
V	**Active networks**	**Holistic approach**, **fully active networks**, regulation incl. active role generators & load	• Increasing network integration costs • Proper incentives network operators & generation and load • Increasing congestion	• Time and location differentiated connection & use of system charges • Smart-meters • Active network management

3.5 Regulatory road map tool

In the previous two Sections we have presented two tables that deal with the two dimensions of system transformation process; the market and network integration phases of (intermittent) RES-E/DG. Consequently, the next step is to bring those two dimensions together in one graphical scheme that combines the two tables on market and network integration. We refer to this scheme as the generic regulatory road map scheme. The basic scheme is depicted in Figure 3.2.

The different stages of market integration are depicted on the horizontal axis. The horizontal axis at the same time also represents the impact of intermittent RES-E/DG on the electricity system. This can be interpreted as either an amount of RES-E/DG in the electricity system or the relative impact of existing RES-E/DG. The amount / impact of RES-E/DG is defined by the qualifications of 'low', 'moderate', and 'high' and related to the market integration stages. Based on the two axis we can depict (1) the current situation with respect to the amount / impact of RES-E/DG in the current electricity system, (2) the current situation with respect to network integration in combination with the current level of market integration, and (3) the likely end-state (i.e. future point in time, say around 2020) of intermittent RES-E/DG integration.

The latter identifies the required level of network and market integration and is dependent on the likely system impact at the end of the time horizon. Within this figure, horizontal shifts represent a shift in the stage of market integration, whereas vertical shifts represent a shift in the stage of network integration. At a given current level of network integration it is possible that two bullets are inserted one to reflect the level of market integration and the other the actual amount / impact of intermittent RES-E/DG on the other. In Figure 3.2 it reflects that the current market integration level can successfully accommodate more intermittent RES-E/DG without a change being required in the level of market integration. When actual market integration is just sufficient to accommodate the associated level of intermittent RES-E/DG, then one bullet represents the starting point of the road map. The movement from the initial starting point to the envisioned end (state) point is referred to as the regulatory road map. Between starting and end point, intermediate points have been established, for two reasons. Firstly, step-by-step changes of regulation are deemed better than implementation of all kind of measures at once because of complexity and/or required regulatory coordination, technology development, investments, consumer participation or preparatory actions for later phases. Secondly, a number of specific measures is linked to one of the less advanced market or network integration phases; not taking into account these recommendations implies that some extensive and costly measures are implemented, while more cost efficient measures are ignored. The latter is clearly detrimental to the integration of large amounts of RES-E/DG. Finally, a part of the cells in the Figure is marked grey, implying that at very low levels/shares of RES-E/DG there is no need for electricity systems to advance to the higher level market or network integration stages from a point of view of optimally efficiently integrating intermittent RES-E/DG.

When applying this generic framework to specific countries it can be discussed what the optimal route concerning market and network regulatory actions is. This is dependent on country specific conditions, i.e. system conditions. For example, a country that is well-interconnected with the other electricity systems abroad might be able to significantly increase its RES-E/DG share in the country without having to alter existing network regulation (i.e. a move right-ward in the generic road map scheme).

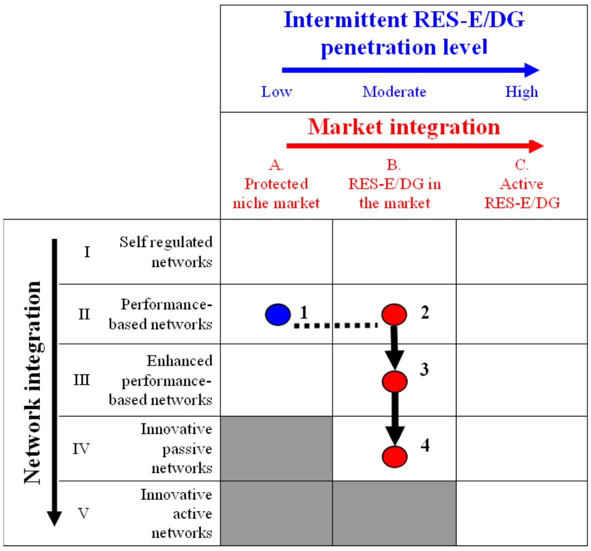

Figure 3.2 *Generic regulatory road map scheme*

4 Regulatory road maps

In this section we will apply the developed road map methodology derived in the former section to two countries; Denmark and Germany. For the other three countries, the Netherlands, Spain, and the United Kingdom, we refer to the full report on regulatory roadmaps (Van der Welle *et al.* 2009). The following basic questions will be answered for the two selected countries:

1. What is the expected development of intermittent RES-E/DG in 2020?
2. What is the associated required end-state of market and network integration?
3. What is the current state of market and network integration?
4. Which action points can be derived over time, and who should take responsibility?

4.1 Denmark

Development of intermittent generation

The figure below shows the expected development of the penetration rate of intermittent RES-E (defined as onshore and offshore wind and photovoltaics) up to 2020. In 2020 the envisaged average penetration rate is approximately 35%.

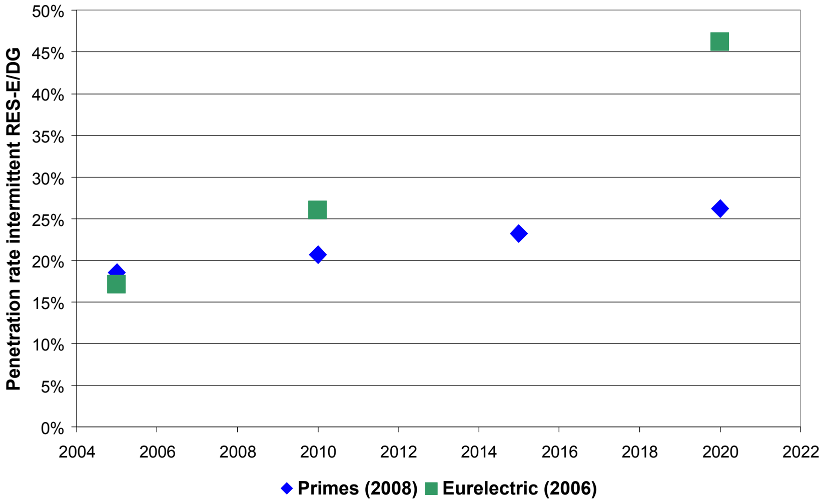

Figure 4.1 *Penetration rate of intermittent RES-E in different studies*[3]

Required end-state of market and network integration

Market integration

Based on the projected developments in electricity production in Figure 4.1 above and the 2020 sustainability targets for Denmark (see **Error! Reference source not found.**) we conclude that the likely level of intermittent RES-E/DG in 2020 can be qualified as high. However, based on a study of Energinet.dk (2007) impacts of additional intermittent generation on the balancing market seem to be moderate. Concerning energy markets for longer time frames (intraday, day-ahead, forward markets); a further increase of price variability is expected.

As a result, Denmark predominantly faces the impacts below related to the 'Active RES-E/DG' stage of market integration in 2020 (see Table 1):

- High penetration level of RES-E/DG
- Substantial increase of system balancing costs
- Decreased profitability for conventional base-load power plants at the margin. Possible lack of flexible generation capacity at critical system times.

In order to mitigate these impacts, Table 1 indicates that Active RES-E/DG is the assumed optimal market integration stage at the end-point of the roadmap i.e. in 2020.

Network integration

Expected impacts on the distribution and transmission networks in 2020 are quite substantial in terms of required additional network capacity due to the connection of concentrated new offshore wind farms and new onshore wind turbines. The former increases the distance electricity has to be transported to reach load, while the latter induces more upward network flows from distribution to transmission network levels. Since most new wind turbines will be placed offshore, presumably 50%[4] of installed wind power capacity is directly connected to transmission networks in 2020. This is in contrast with the current situation, with the majority of intermittent generation connected to the distribution networks (60 kV or lower). Nevertheless, not only the TSO but also the DSOs have to integrate an increasing amount of wind generation in their grids in the period up to 2020.

More specifically, Denmark will face the following network-related impacts of intermittent renewable generation (see Table 2):

---

[3] Calculations based on production (TWh) figures. Penetration rate as percentage of total electricity production.
[4] Based on information provided by Risoe and own calculations.

- Network congestion in Western-Denmark in case of prolonged increase of wind power
- Significant unplanned electricity flows ('loop flows') occur on interconnections between Western-Denmark and Germany (Forbes, 2009)
- Higher diversity of network flows in distribution networks due to connection of DG requires more network reinforcements, which are utilised in a limited number of situations decreasing overall network utilisation.

These impacts imply also considerable economic costs, since they cannot be resolved easily for at least two reasons. Firstly, conventional 'hardware' solutions (new lines and cables) for more network controllability are impeded by social acceptance issues, delaying and sometimes requiring burying of lines. Secondly, efficiency notions ask for consideration of alternative network planning philosophies in the distribution networks.

Consequently, in the future Denmark seems to face a number of network impacts, with associated fast increasing network integration costs of renewables. In order to limit the cost impacts for both (distributed) generators and consumers to the efficient costs, Table 2 indicates that an transition to an more active type of network management of both distribution and transmission networks is necessary for Denmark at the end-point of the roadmap.

Current state of market and network integration

Based on the following description of the current situation on different issues relevant for the integration of RES-E/DG in markets and networks, the current stages of market and network integration can be established.

Market integration

The RES-E/DG production as fraction of total electricity production is already about 20% in Denmark. Clear effects of intermittent production on day-ahead market prices have been identified (Zvingilaite *et al.*, 2008; Andersen *et al.*, 2009). Electricity market rules have been explicitly acknowledged by the Danish TSO as of decisive importance to the utilisation of the electricity system in the context of the increasing share of wind generation. The attention for market rules is also proven by the fact that:

- For wind generation a feed-in market support scheme is already in place
- RES-E/DG already provides some ancillary services through aggregators
- The current balancing market design is characterized by balancing responsible parties including RES-E/DG, short gate closure time of day-ahead market and deployment of contingency units for emergency situations.

Therefore one could conclude that the current stage of market integration in the roadmap corresponds to stage B (RES-E/DG in the market).

Network integration

The transmission network in Denmark is already deployed with several steering and control possibilities like HVDC cables connecting the Nordel and UCTE systems. Although some pilot projects for first phases of active network management of distribution networks are ongoing, in practice distribution networks are still managed by the 'fit-and-forget' philosophy, implying monitoring and control possibilities of network (actors) are highly limited. Network regulation is characterized by revenue cap regulation with quality of service regulation but without explicit innovation incentives.

Therefore, we conclude that the current network integration stage is stage II (performance-based networks).

Regulatory road map

Combining the end-points for both market and network integration sets the end-point in Figure 4.2 below at stage V-C in 2020. The same procedure sets the starting point at stage II-B in 2009. Consequently, the route from the initial starting point to the envisioned end point can be established. Mainly vertical shifts are required in the regulatory roadmap, as the main recommendations concern improving network integration. Between starting and end point, two intermediate points have been established, for reasons explained in section 3.

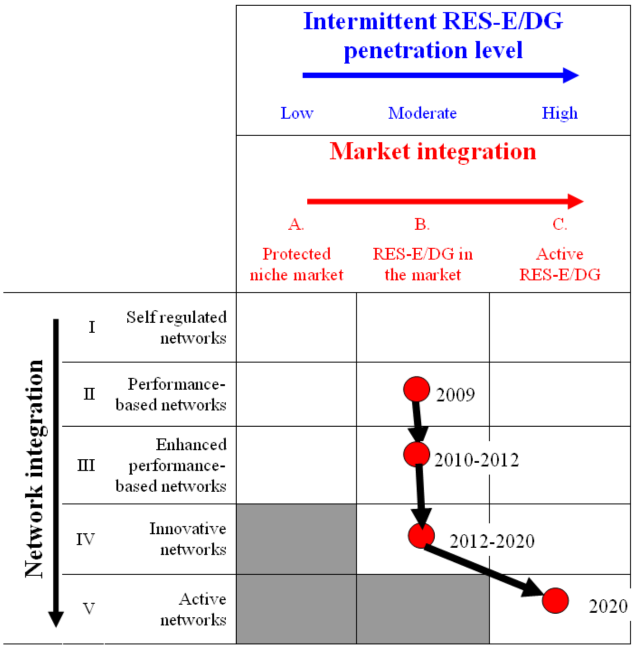

Figure 4.2 *Regulatory road map scheme Denmark: complete route 2009-2020*

Regulatory action plan

With help of Table 1 and Table 2 above the general recommendations coupled to the selected regulatory market and network phases can be derived. Besides, some country-specific measures are provided, which are tailored to the specific system conditions of Denmark. These recommendations should be considered as a package of measures, since measures in all system sectors i.e. generation, demand, networks and markets, are required for a cost-efficient integration of intermittent renewables in the system. In addition, a number of recommendations can be considered as mutual dependent (e.g. harnessing the benefits of smart metering for system integration requires the implementation of time-variable pricing for consumers). At the same time, some measures are more important than others; therefore the most urgent and critical actions to improve system flexibility are highlighted.

The Table also indicates the system actors who are first responsible for preparing, approving and implementing these sets of recommendations. Short-term actions are actions possible in the next years, while medium term actions due to complexity and/or required regulatory coordination, technology development, investments, consumer participation or preparatory actions only can be fully implemented after a couple of years, but well before 2020. Long-term actions should take place around 2020.

Table 3 *Action plan for Denmark*

<table>
<tr><th>Actor</th><th>2010-2012</th><th>2012-2020</th><th>2020</th></tr>
<tr><td>Govern-ment</td><td>• Oblige feed-in premium for CHP < 5 MW
• Establish common standard for smart metering and develop common communication standard
• Coordination procedure to overcome objections against new lines</td><td>• Introduce smart metering at premises of LV customers
• Decrease market premium to stimulate RES-E/ DG to consider provision of ancillary services</td><td></td></tr>
<tr><td>Regu-lator</td><td>• Innovation incentives for DSOs
• Evaluate network planning standards
• Account for differential DG impacts in network regulation</td><td>• Network planning with dynamic reserves
• Network simulation tool for network planning & investments</td><td></td></tr>
<tr><td rowspan="3">TSO</td><td colspan="2">• Refine cross-border balancing</td><td></td></tr>
<tr><td></td><td colspan="2">• Contract additional balancing power outside the market
• Interruptible contracts for loads and DG
• Enable wider possibilities for provision of ancillary services by DG
• Contribute to TSO colloboration for allowing optimization of common capacity calculation & allocation</td></tr>
<tr><td>• Increase Use-of-System charges for generators
• Implicit auctions for day-ahead time frame on interconnections with Germany
• Possibilities for provision of ancillary services by RES-E/DG</td><td>• Time-differentiated UoS charges
• Reduce minimum VPP size to 5 MW</td><td>• Reduce minimum VPP size to 1 MW
• Real-time and locational (zonal) differentiated UoS charges
• Consumers take part in virtual power plants</td></tr>
<tr><td>DSOs</td><td>• Demonstrate smart home area networks for advanced load control</td><td>• Demonstration projects about smart grids and smart metering
• Introduce smart metering at premises of LV customers
• Pilot projects for testing communication infrastructure for hourly/quarterly metering
• Implement smart home area networks for advanced load control</td><td>• Introduce real-time pricing of energy and network charges for customers
• Increase application of active network management</td></tr>
<tr><td>Suppliers</td><td>• Introduce simple time-differentiated prices at wider scale</td><td></td><td>• Oblige time-differentiated prices</td></tr>
<tr><td>RES-E operators</td><td></td><td>• Add heat storages, heat pumps or electric boilers to CHP units</td><td>• Invest in new heat or electric storage facilities</td></tr>
</table>

From the action plan we select the most urgent and critical actions to improve the system flexibility **in the short term**. The roadmap indicates that the main actions are required for improving network integration, as on the one hand major grid overloads and network congestion are expected, and on the other hand conventional hardware solutions are prevented by social acceptance issues and increasing cost burdens.

First of all, generators should face the effects of their production and siting decisions on network investments; therefore *use-of-system charges for generators* should be set at a more substantial level. Furthermore, *innovation incentives* for DG are required to overcome adverse regulatory incentives. Consequently, network capacity can be enhanced against lower costs in the medium term through the introduction of active network management. Finally, *current network planning standards should be evaluated* in order to allow for dynamic reserve requirements in network planning in the longer term. Especially in a system with high and increasing shares of wind generation, dynamic planning criteria can lower network integration costs substantially. For the explanation of the other options, we refer to Van der Welle *et al.* (2009).

4.2 Germany

Development of intermittent generation

The figure below shows the expected development of the penetration rate of intermittent RES-E (defined as onshore and offshore wind and photovoltaics) in time. In 2020 the envisaged average penetration rate is approximately 16%.

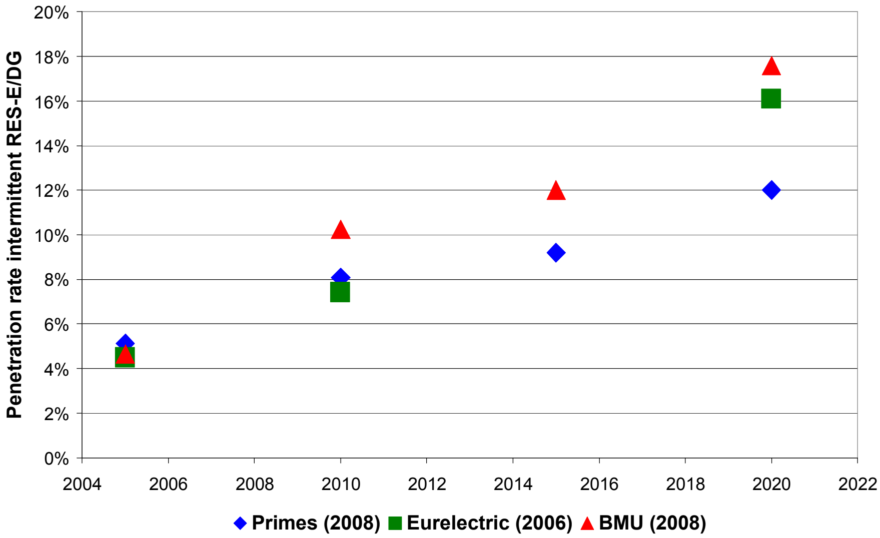

Figure 4.3 *Penetration rate of intermittent RES-E in different studies*[5]

Required end-state of market and network integration

Market integration

Based on the projected developments in electricity production and the 2020 sustainability targets above, we conclude that the likely share of intermittent RES-E/DG in 2020 can be qualified as moderate.[6] Impacts on the balancing market are assumed to be high (based on Dena, 2005). Concerning energy markets for longer time frames (intraday, day-ahead, forward markets); a higher price variability is expected. Although impacts of intermittent generation on the balancing market are high, Germany predominantly faces the impacts related to the 'RES-E/DG in the market' stage of market integration in 2020 (see Table 1):

- Moderate penetration level of RES-E/DG
- Need for differentiated prices which reflect system conditions
- Decreasing profitability for conventional base-load power plants at the margin. Possible lack of flexible generators at critical system times.

In order to mitigate these impacts, Table 1 indicates that RES-E/DG in the market is the assumed market integration stage at the end-point.

Network integration

Expected impacts on the distribution and transmission networks in 2020 are quite substantial in terms of required additional network capacity due to the connection of concentrated new offshore wind farms and new onshore wind. The former increases the distance the electricity produced has to be transported, while the latter induces more fluctuating network flows on the distribution level and upward network flows from distribution to transmission network levels. Currently the

---

[5] Calculations based on production (TWh) figures. Penetration rate as percentage of total electricity production.

[6] Shares of intermittent RES-E/DG below 10% are characterised as low; between 10-30% as moderate; and above 30% as high.

large part of all wind generation, 85-90%, is connected to distribution networks; this is expected to change in the period up to 2020 when a large amount of offshore wind parks is connected. More specifically, Germany faces the following network-related impacts of intermittent renewable generation (see Table 2):

- Substantial network congestion is expected in Germany for 2015; according to EWIS (2009) up to 5000 MW of re-dispatch of conventional generation is required by that date since RES-E/DG has priority dispatch.
- Although Germany imports renewable power from Denmark, there is a net export of renewable power. Unplanned electricity flows ('loop flows') due to wind generation occur mainly on international interconnections with The Netherlands and Poland.
- Higher diversity of network flows in distribution networks due to connection of DG requires more network reinforcements, which are utilised in a limited number of situations decreasing overall network utilisation rate.

These impacts imply also considerable economic costs, since they cannot be resolved easily for at least two reasons. Firstly, conventional 'hardware' solutions (new lines and cables) for more network controllability are impeded by social acceptance issues, delaying and sometimes necessitating burying of lines. Secondly, efficiency notions ask for consideration of alternative network planning philosophies in the distribution networks.

Consequently, in the future Germany faces a number of network impacts, with associated fast increasing network integration costs of renewables. In order to limit these cost impacts for both (distributed) generators and consumers to the efficient costs, Table 2 indicates that a transition to a more innovative type of network management of both distribution and transmission networks is necessary for Germany at the end-point of the roadmap.

Current state of market and network integration

Based on the following description of the current situation on different issues relevant for the integration of RES-E/DG in markets and networks, the current stages of market and network integration can be established.

Market integration

The RES-E/DG production as fraction of total electricity production is already moderate in relative and high in absolute terms. Clear effects of intermittent production on day-ahead market price variability have been identified. Therefore one could conclude that the current stage of market integration is stage B (RES-E/DG in the market). However, when looking at the current market design and the actual opportunities of RES-E/DG this corresponds more with a less advanced stage of market integration (stage A) since:

- The support scheme is the feed-in tariff scheme.
- The current balancing market design is characterized by a central balancing mechanism without balancing responsibility for RES/DG. Furthermore, RES/DG has priority access to the grid and is not considered as an option for congestion management.
- Gate closure time of the balancing market is long, since the gate closure time is fixed (i.e. not rolling on hourly basis like in several other European countries).
- At the positive side: CHP already takes part in the provision of balancing services through virtual power plants, system service bonus is in place.
- Combining these observations on the current level of intermittent generation and market integration and corresponding to Table 1, for the case of Germany we state that the starting point of the roadmap is *protected niche market / DG/RES-E in the market*.

Network integration

The German transmission networks will be deployed with steering and control possibilities like HVDC cables and phase shifters. However, distribution networks are still managed by the 'fit-and-forget' philosophy, implying monitoring and control possibilities of network (actors) are highly limited. Concerning network regulation, (distributed) generators do not have to pay Use of System charges; therefore network incentives to generators to behave in line with system demand are negligible. Recently incentive regulation became in force; within this framework quality of service regulation will be implemented next year. DG is considered as a cost driver within network regulation and a system services bonus is provided to wind turbines, which may force them to innovate. Therefore, Germany is currently on the *intersection of performance based networks and enhanced performance-based networks* (see also Table 2).

Regulatory road map

Combining the end-points for both market and network integration sets the end-point in Figure 4.2 below at stage IV-C in 2020. The same procedure sets the starting point at stage II/III-A/B in 2009. Consequently, the route from the initial starting point to the envisioned end point can be established, including one intermediate point. Both horizontal and vertical shifts are required in the regulatory roadmap, requiring implementation of both market integration and network integration recommendations.

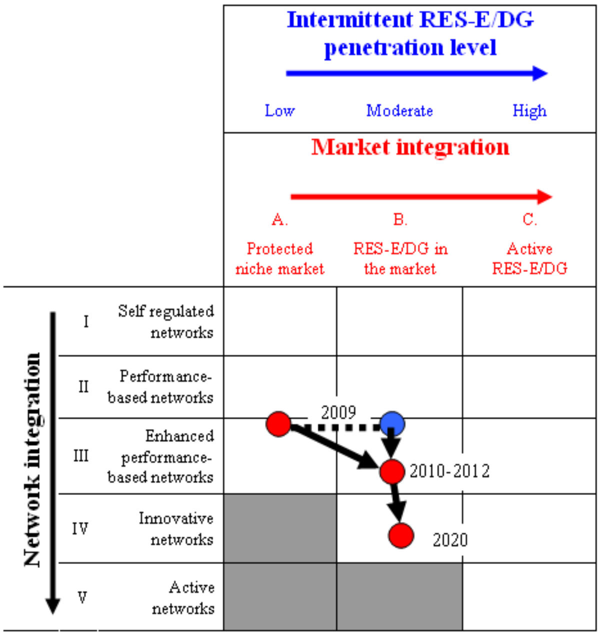

Figure 4.4 *Regulatory road map scheme Germany: complete route 2009-2020*

Regulatory action plan

In line with Table 1 and Table 2 above the general recommendations coupled to the selected regulatory market and network phases can be derived. Besides, some country-specific measures are provided, which are tailored to the specific system conditions of Germany. These recommendations should be considered as a package of measures, since measures in all system sectors i.e. generation, demand, networks and markets, are required for a cost-efficient integration of intermittent renewables in the system. In addition, a number of recommendations can be considered as mutual dependent (e.g. harnessing the benefits of smart metering for system integration requires the implementation of time-variable pricing for consumers). At the same time, some measures are more important than others; therefore the most urgent and critical actions to improve system flexibility are highlighted.

The Table also indicates the parties who are first responsible for preparing, approving and sometimes implementing these recommendations. Short-term actions are actions possible in the next years, while medium term actions due to complexity and/or required regulatory coordination, technology development, investments, consumer participation or preparatory actions only can be fully implemented after a couple of years, but well before 2020.

Table 4 *Action plan for Germany*

Actor	2010-2012	2020
Govern-ment	• **Feed-in premium besides feed-in tariffs** • **Abolish priority dispatch of RES-E** • **Minimum functional requirements to smart meters & more frequent meter reads** • One-stop shop approach for flexible generation • Coordination procedure to overcome objections against new lines	• **Oblige feed-in premium system**
Regu-lator	• **Innovation incentives for DSOs** • Evaluate network planning standards • **All generators balancing responsible**	• **Market-based national CM** • Network planning with dynamic reserves • Network simulation tool for network planning & investments
TSO	• **Rolling gate closure time for balancing market** • Cross-border balancing • Contract additional balancing power outside the market • **Use-of-System charges for generators** • Fine-tune system services bonus	• Reduce prequalification criteria for balancing • Reduce minimum VPP size to 5 MW • **Enable wider possibilities for provision of ancillary services by DG** • Interruptible contracts for medium size loads • **Time-differentiated UoS charges**
DSO	• Demonstration projects about smart grids, smart metering and advanced load control • Demonstrate smart home area networks for advanced load control	• Pilot projects for testing communication infrastructure for hourly/quarterly smart metering
Suppliers	• Introduce simple time-differentiated prices at wider scale	• **Oblige time-differentiated prices**
RES-E opera-tors		• Add heat storages or back-up boilers to CHP units

From the action plan we select the most urgent and critical actions to improve the system flexibility **in the short term**. The roadmap indicates that the main actions are required for improving both network and market integration. Although network integration remains the main issue, during our analysis it became clear that the improvement of market flexibility may deliver the largest quick wins for the German power system in the short term, limiting to some extent also required network integration actions. More market flexibility may limit the demand for network flexibility dramatically by stimulating generators to take into account the effects of their behaviour on the power system. First of all, when a *feed-in market premium scheme* is implemented instead of feed-in tariffs, DG/RES-E receives incentives to take into account the system demand for electricity in its production decisions. Secondly, difficult network situations can be dealt with more effective and efficiently when DG/RES-E disposes *no longer* of *priority access*, but is allowed to be curtailed against a cost-reflective payment. Finally, the demand for system balancing can be decreased substantially if DG/RES-E becomes *balancing responsible* and a *rolling gate closure time* for the balancing market is introduced. Apart from this, network integration actions are required.

5 Conclusions

5.1 Recommendations for regulatory actions

The regulatory road maps for Denmark and Germany take into account varying levels of RES-E/DG penetration and intermittent technologies. Consequently some of the system impacts are different and so are the solutions (response options and regulatory actions) per country and roadmap.

Table 5 provides an overview of the main recommendations and actions for both countries.[7] The Table shows also the similarities and differences in the recommendations.

Table 5 *Overview of recommended actions per country*

Topic	Recommendation	Country Denmark	 Germany
Network integration			
Network charging	Shallow connection charges for all generators and cost-reflective use of system charges for generators	✓	✓
Network planning	Implement dynamic reserve requirements	✓	✓
	Introduce explicit innovation incentives in network regulation	✓	✓
Congestion management	Implement market-based congestion management	✓	✓
Market integration			
Demand response	Establish common standard for functionality of smart meters	✓	✓
	Implement basic time-differentiated prices for all consumers	✓	✓
Balancing market	Introduce balancing responsible parties		✓
Ancillary services	Possibilities for DG/RES-E to provide ancillary services	✓	✓

The recommended actions are briefly explained below.

Connection and Use of system charges

The integration of increasing amounts of RES-E/DG gives rise to increasing costs in connecting and operating networks. These costs have to be borne by the users of the system, i.e. generators and consumers.

The costs of connection of network users and the operation of the network are paid by network users. These network costs are generally subdivided in costs of connecting users (generators and consumers) to the grid and costs for operation of the electricity system i.e. transport and complementary system services. Connection costs are passed on to network users by connection charges; use-of-system costs are passed on by use-of-system (UoS) charges.

Two distinct approaches of calculating connection charges can be distinguished: shallow and deep charges. Shallow connection charges include only the cost of connecting the customer to the nearest point in the distribution network. The costs of additional network reinforcements are not included in these charges. As opposed to shallow connection charges, deep connection charges contain the costs of network reinforcements both at the transmission and distribution level as well as the direct connection costs.

For providing fair and non-discriminatory network access to the network for different kinds of generators, including small RES-E/DG units, it is important to introduce shallow connection charges. This avoids large upfront costs for RES-E/DG, which would discriminate against DG as compared to centralised generation. Besides, this kind of connection charges lowers transaction

[7] For the regulatory roadmaps of The Netherlands, Spain and the United Kingdom and the derived regulatory actions of these roadmaps, we refer to Van der Welle *et al.* (2009).

costs to DG by keeping the calculation straightforward and transparent and avoiding negotiations about the “deep” connection cost component. Both Denmark and Germany have already implemented a shallow connection charges methodology for all connection levels.

However, from the point of view of the system operators, the implementation of shallow connection charges is not a favourable option if the costs of network reinforcement due to DG are not recovered in some way. Therefore, it is recommended to socialize the incremental grid reinforcement cost among all network users by way of *use of system (UoS) charges*. Currently, UoS charges are mainly levied upon consumers. Consequently, generators do not receive an incentive to take into account the network costs that the system will incur as a result of their decision to install a new plant at a certain location. However, this is clearly inefficient from a system and welfare point of view and causes higher network integration costs. Therefore, the introduction of cost-reflective use of system charges for generators is recommended for both Denmark and Germany. Coordinated implementation of this measure, at least at regional level but preferably at European level, is highly recommended since an uneven implementation of UoS charges for generators results in an uneven playing field across the EU.

Dynamic reserve requirements

In network planning a number of standards are used in order to guarantee quality of supply. The maximum capacity of networks circuits is nowadays calculated using static assumptions with standard load profiles among others. Therefore, reserve requirements are static as well. When reserve requirements depend on actual (short-term) wind forecasts, additional network capacity may become available and network investments due to connection of additional renewable generation may be lowered without compromising security of supply. This recommendation applies to both countries at hand.

Explicit innovation incentives in network regulation

Network planning is also influenced by network regulation, both at TSO and DSO level. Generally, within Europe *incentive regulation* with price or revenue caps is applied to network operators. Incentive regulation can be characterised by the strong focus on short-term cost-efficient network operation, which is necessary to decrease the monopoly profits of network operators but comes at the expense of more risky investments contributing to long term efficiency. As a result, already existing risk-averse behaviour of network operators is reinforced, which impedes investments in active network management technologies by DSOs. Therefore, it is recommended to add explicit innovation incentives to incentive regulation like the IFI type of incentives in the United Kingdom. These incentives effectively increase the scope for innovation by DSOs and therefore may speed up the implementation of active network management. This recommendation applies to both Denmark and Germany.

Market based congestion management

Installing new conventional and RES generators may require reinforcing the transmission and distribution grids, especially when new generation is either located far from load or production is exceeding consumption sometimes. Reinforcing the network usually takes more time than installing new plants, and starts only when generation consents have been provided. Consequently, existing network capacity falls short and congestion will emerge. For interconnections already implementation of market based congestion management is required by EC regulation 1228/2003. Countries are increasingly using implicit and explicit auctions for cross-border congestion management. Also for national connections implementation of market-based congestion management is recommended in order to relieve congestion against lowest costs for all market actors including RES-E/DG as well as to diminish the occurrence of congestion. The recommendation applies to both countries.

Common standards for functionality of smart meters

Common standards for smart meters are required in order to ensure a certain standard of data quality and functionality within country. A common standard prepares a system for an increase of market-based demand response in the future and guarantees that the whole demand response potential can be utilised. An increase of demand response is valuable to increase the flexibility of the system to react to the higher variability of generation in systems with high penetrations of wind and PV. At present, common standards have not yet been defined. Therefore, it is recommended to establish common standards for smart meter functionality in Denmark and Germany.

Basic time-differentiated prices for all consumers

Smart meters are useful but not sufficient for an increase of demand response. Therefore, consumers need also to receive signals about the system status. In a liberalised market, this signal should be provided to consumers by making prices more variable. As a first step, prices should be differentiated to peak, shoulder and off-peak periods. In the medium term, i.e. before 2020, consumers should be facing hourly-based prices. It should be noted that the communication of hourly prices to final consumers itself might not always automatically induce price responsiveness. This might vary over the various types of electricity consumers. In order to fully use the demand response potential with for example household consumers automated response devices should be developed and implemented in parallel, since especially these consumers might be reluctant to make personal, real-time decisions on electricity consumption and responsiveness to electricity price changes.

Balancing responsible parties

The Scandinavian type of balancing market design with balancing responsibility for all connected parties (including RES-E/DG) provides an incentive to both generators and consumers to limit their imbalance as far as possible; connected parties have to pay imbalance payments in case their actual production deviates from their production forecast. Consequently, at a system level the amount of balancing power to be provided is reduced compared to a system without balancing responsibility. This allows for the integration of RES-E/DG production in the electricity system against lower costs. It is recommended that a balancing system with balancing responsibility for all connected parties will be introduced in Germany. In Denmark such a system has already been implemented in the past.

Possibilities to provide ancillary services

Currently requirements of system operators as well as obliged provision of some ancillary services by conventional generation, prevent the delivery of ancillary services (including balancing services) by RES-E/DG. However, for both system (dramatic decrease of conventional generation in some regions) and level playing field considerations, it is deemed useful that RES-E/DG will be enabled to provide ancillary services. Therefore, requirements to RES-E/DG, including aggregators of a portfolio of small (distributed) generation assets, and all minimum size limits of the underlying individual installations or connections should be removed as far as economically and technically feasible. Furthermore, the ancillary services market design should allow for sufficient AS provision, efficient contracting of these services, as well as for a good trade-off for generators between either the provision of energy on the one hand or the provision of one of the different ancillary services on the other. Especially, services with a system-wide character (i.e. tertiary reserves) may be contracted through markets (i.e. auctions) instead of self-procurement by the TSO or bilateral contracts.[8] Consequently, RES-E/DG may diversify their revenue streams. Since today there is little experience with RES-E/DG providing ancillary services, further field testing/research is required. The recommendation applies to both Denmark and Germany.

5.2 Recommendations for further research

Finally, on an EU or national level this analysis could be followed by a more detailed and quantitative analysis of the different measures proposed and assessment of cost and benefits for a specific system. The actual added costs and benefits are dependent on many country-specific conditions such as market structure, geographical conditions, and prevailing regulation. Such analysis would give further insight in the prioritisation of regulatory actions over time. Whereas

[8] For local services like the provision of reactive power, the number of service providers may be too small for a market in some cases.

the prioritisation and timing of regulatory actions in this study could only be highlighted indicatively, quantification-based recommended actions could give rise to more definite priorities and timing. This remains a challenge for future research.

6 References

Andersen, F.M., Grohnheit, P.E., Mancarella, P., Pudjianto, D., Strbac, G., Olmos, L., Gómez, T. and E. Lobato, deliverable 7 of the RESPOND project, July 2009. Available at: http://www.respond-project.eu/.

BMU (2008). Weiterentwicklung der Ausbaustrategie Erneuerbare Energien: Leitstudie 2008 (In English: Lead Study 2008: Further development of the 'Strategy to increase the use of renewable energies' within the context of the current climate protection goals of Germany and Europe), October 2008.

Dena (2005), Energiewirtschaftliche Planung für die Netzintegration von Windenergie in Deutschland an Land und Offshore bis zum Jahr 2020, February.

European Council (2009), Directive 2009/28/EC on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/ECDirective, OJ L 140/16, 5.6.2009.

Energinet.dk (2007), System Plan 2007, October.

Forbes, K.F. (2009), Space Weather, Electricity Flows, and the Smart Grid, Third Space Weather Enterprise Forum, Washington D.C., 20 May 2009.

Holttinen, H. (2007), Presentation IEA task 25 for Greennet.

Lobato, E., Olmos, L., Gómez, T., Andersen, F.M., Grohnheit, P.E., Mancarella, P. and D. Pudjianto (2009), Regulatory and other Barriers in the implementation of Response Options to reduce impacts from variable RES sources, deliverable 6 of the RESPOND project, January 2009. Available at: http://www.respond-project.eu/.

Ramsay, C., G. Strbac, A. Badelin, and C. Srikandam (2007). Impact analysis of increasing (intermittent) RES and DG penetration in the electricity system, deliverable 4 of the RESPOND project, November 2007. Available at: http://www.respond-project.eu/.

Van der Welle, A.J., J. de Joode, and F. van Oostvoorn (2009). Regulatory Roadmaps for the Optimal Integration of intermittent RES-E/DG. Final Report of the RESPOND Project, deliverable 8 of the RESPOND project, August 2009. Available at: http://www.respond-project.eu/.

Zvingilaite, E., H.K. Jacobsen, E. Poza Sanchez, A. Van der Welle (2008). Overview of optimal market response options: Identification and analysis of market response options, deliverable 5 of the RESPOND project, June 2008. Available at: http://www.respond-project.eu/.