IMPROGRES

Improvement of the Social Optimal Outcome of Market Integration of DG/RES in European Electricity Markets

Regulatory strategies for selected Member States (Denmark, Germany, Netherlands, Spain, the UK)

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Project objectives

The IMPROGRES project aims to identify possible improvements in the direction of a socially optimal outcome of market and network integration of distributed generation (DG) and electricity production from renewable energy sources (RES-E) in Europe with a focus on efficient interactions between distribution networks and embedded DG, fossil-based and from renewable energy sources (RES). To that effect the project sets out to:

- identify current interactions between DG/RES businesses, distribution system operators (DSOs) and energy markets directed at coping with increased DG/RES penetration levels,
- develop DG/RES-E scenarios for the EU energy future up to 2020 and 2030,
- quantify, for selected network operators, the total future network costs that have to be incurred to accommodate increasing shares of DG/RES according to the DG/RES-E scenarios,
- identify cost minimising response alternatives to accommodate increasing penetration levels of DG/RES for the same network operators, as compared to prevailing conventional DSO practices,
- recommend policy responses and regulatory framework improvements that effectively support improvements towards a socially optimal outcome of integrating DG/RES in European electricity networks and markets.

Project partners

- Energy research Centre of the Netherlands (ECN), The Netherlands (coordinator)
- Liander, (previous name: Continuon) The Netherlands
- Fraunhofer Institute for Wind Energy and Energy System Technology IWES (previous name: ISET), Germany
- MVV Energie, Germany
- Risø National Laboratory for Sustainable Energy, Technical University of Denmark (Risø DTU), Denmark
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EXECUTIVE SUMMARY

This Work Package 6 report of the IMPROGRES project provides an overview of regulatory strategies and incentives, conducive to (i) network integration of increasing levels of distributed generation including notably intermittent renewable technology such as wind power and solar photovoltaics (PV) as well as (ii) options for reducing impacts on surging network integration costs. Similar to the IMPROGRES project in general, this report focuses on European distribution networks. It includes specific country studies of Denmark, Germany, the Netherlands, Spain and the UK. This summary presents the main findings of this report.

Integration of distributed generation, notably from renewable, (DG/RES) in networks
When distributed electricity supply grows to a certain non-negligible level, it can no longer be ignored in planning and operation of the electricity networks. With progressive use of stochastic, renewable energy sources by decentralized generators connected to distributed networks, flows of energy between transmission network, distribution network and end-use customers take on a pattern that is to an increasing extent bi-directional and variable in nature. As a result, DSOs have to deal with an increasing number of different network situations. The network management of all these different situations will be increasingly costly. This is particularly true if the current 'fit-and-forget' network management philosophy is maintained. This philosophy means that the network itself is prepared for all possible network situations and no active contribution of generation and demand to network operation is expected. When network reinforcements have to cover all possible situations, utilization of network assets decreases. This, in turn, implies increasing costs. Therefore it is highly desirable that active management of distribution network components be considered deploying ICT technology and including the control of power injections by generating installations on the one hand and the power uptake by load devices on the other. This will increase the visibility of DG by network operators. Moreover, active network management (ANM) of distribution networks may contribute to the realisation of potential advantages of distributed generation, such as reduced system losses, improvement in voltage profile and better power quality in the existing transmission and distribution network.

The benefits and costs of active network management for the three case studies were identified in the D6 report. In these case studies a cost saving potential was found of about 5-10% of the additional network cost. Extrapolating these findings to the EU-27 would imply network cost savings due to active network management of about € 1-3 billion in the period up to 2020. To identify opportunities for realization of this cost savings potential, existing network planning and innovation practices were analysed and recommendations for improvement were formulated.

Regulatory issues for better integration of DG in networks
Several other key regulatory issues concerning the integration of DG in networks were also identified and will be elaborated below, i.e. network cost recovery, network charging, interaction of network charging and support schemes, and the incentivisation of demand response.

a) *Network cost recovery*

Current network regulation does not yet (fully) consider the effects of the energy transition that is taking place. Regulators often do not allow for network costs caused by the increasing amount of energy produced by DG in the efficiency assessments of DSOs. Consequently, network costs for the integration of DG are not fully recovered by DSOs in areas with large increases of DG.

b) Network innovation

Distribution network planning is currently done according to the “fit-and-forget” paradigm concerning the connection of DG. ANM is not yet implemented on a wide scale due to the fact that regulation often does not allow for realization of full (long-term) potential benefits of ANM for both markets and networks. DSOs benefit only partially from ANM types of innovations as part of the benefits flow to other parties in the electricity value chain such as generators, suppliers and loads. When DSOs experience full costs but not full benefits of investments in ANM, this affects their trade-off between conventional network solutions and ANM. Consequently, in a number of cases they will be biased to invest in conventional grid solutions instead of ANM. Therefore, part of the smart grids projects will not be realized, although these are preferable for the country as a whole.

c) *Network charging*

A *shallow connection charge* approach is recommended as this provides a fair and transparent access treatment for DG investors. The remaining costs for integrating distributed generators in networks are usually covered by *use-of-system (UoS) charges*. When distribution grids are increasingly dominated by the requirements of distributed generators, the remaining grid reinforcement costs can no longer be unambiguously attributed to load only. A future with high penetration rates of both load as well as production calls for allocation of part of the grid reinforcement costs to generation. Consequently, Member State governments and regulators are advised to consider the introduction of UoS charges for generators, especially but not only in distribution grids with a high share of DG/RES. These UoS charges should be in line with the level of UoS charges to be introduced at the same time for large conventional generators to balance the impact on the competitive environment of DG producers. It is essential that generators receive due financial signals of the network-cost-consequences of their interactions with the public electricity grid (instead of generation support scheme signals only). Time-of-use signals may contribute to lower network peak demand by shifting generation and consumption to times of lower network utilization. Therefore, UoS charges should preferably be made time-dependent. In the longer term, where applicable, DSOs should be incentivised to supplement UoS charges with locational signals. In that way, potential DG investment will face reduced UoS charges at certain locations where DG investment has a positive network impact and the other way around. For transparency reasons, it is recommended that locational signals be provided directly through network charges.

d) Demand response

Currently, demand response is nearly non-existent. In order to increase the responsiveness of the demand side of the electricity system, the roll-out of smart meters among low-voltage customers is currently ongoing in several Member States. This should be accompanied by sending consumers price and/or volume signals; otherwise customers will probably not react. Price signals would constitute differentiated energy prices. The most common schemes to do so are time-of-use (TOU) prices, real-time pricing (RTP) and critical peak pricing (CPP) schemes. Volume signals include limitations on the consumption of specific loads during a certain time span through, for instance, interruptibility contracts. Additionally, demand response programs should be defined and progressively implemented, starting with those customers that already have smart meters. It is important to carefully define the role of each of the agents involved, especially for the retailers. Home automation should be developed and promoted to harness the demand response potential to a large extent. Evidently, the functionalities of the “smart meters” that are being installed should enable endorsement of such applications.

Regulatory priorities for meeting the EU-2020 targets

A major contribution to the EU objectives towards achieving improved sustainability, security of supply and competitiveness in the energy sector will come from harnessing the potential flexibility in electricity demand and in distributed generation. Regulated network companies have a role in facilitating this process by developing sufficient network capacity, and by establishing advanced metering and communication infrastructure at every grid connection. However, a major part of the benefits of smarter grids will be outside the regulated domain, affecting the relation between customers and energy suppliers or energy services companies. As a consequence, network regulation should give a prominent role to ‘external effects’: cost and benefits outside the network. Developing the infrastructure for smart metering and control of distributed generation and demand response may not be a financially viable ‘smart grids project’ when only viewed from a network cost-benefit perspective.

Summarizing the main *regulatory recommendations* from the IMPROGRES project:

- Choose for *shallow connection charges* to lower the barriers for distributed generation and to simplify connection procedures.
- Introduce *Generation Use of System charges* to provide better incentives for improved network utilization and to improve the financial position of those DSOs with larger shares of distributed generation.
- Introduce more *incentives for DSOs*, preferably output-based, to internalize favourable effects of smart grid solutions for other electricity system actors in DSO investment decisions.
- Support the establishment of a *smart metering infrastructure* as the precondition for further market integration of distributed energy resources.
- Depending on availability of smart meters, *more flexible network tariffs* should be introduced, at least using Time of Use tariff structures, and wherever relevant and possible, also locational incentives.

1 INTRODUCTION

This report provides an overview of regulatory strategies and incentives leading to cost-minimisation of network planning and operation from electricity system perspective in due anticipation of energy futures with high DG/RES penetration rates. The extensive use of renewable energy resources calls for new solutions at all voltage levels. Figure 1.1 below exhibits three main network categories. Of these three categories, the main focus of the IMPROGRES project regards active distribution networks (Smart Distribution Networks). A number of other projects are focusing on transmission networks (IRENE-40, TRADEWIND) and micro grids (MICROGRIDS, MORE MICROGRIDS). Upcoming challenges to European electricity networks can only be properly addressed if measures designed and implemented to make networks future-proof are coordinated at all relevant levels (European, national, and regional).

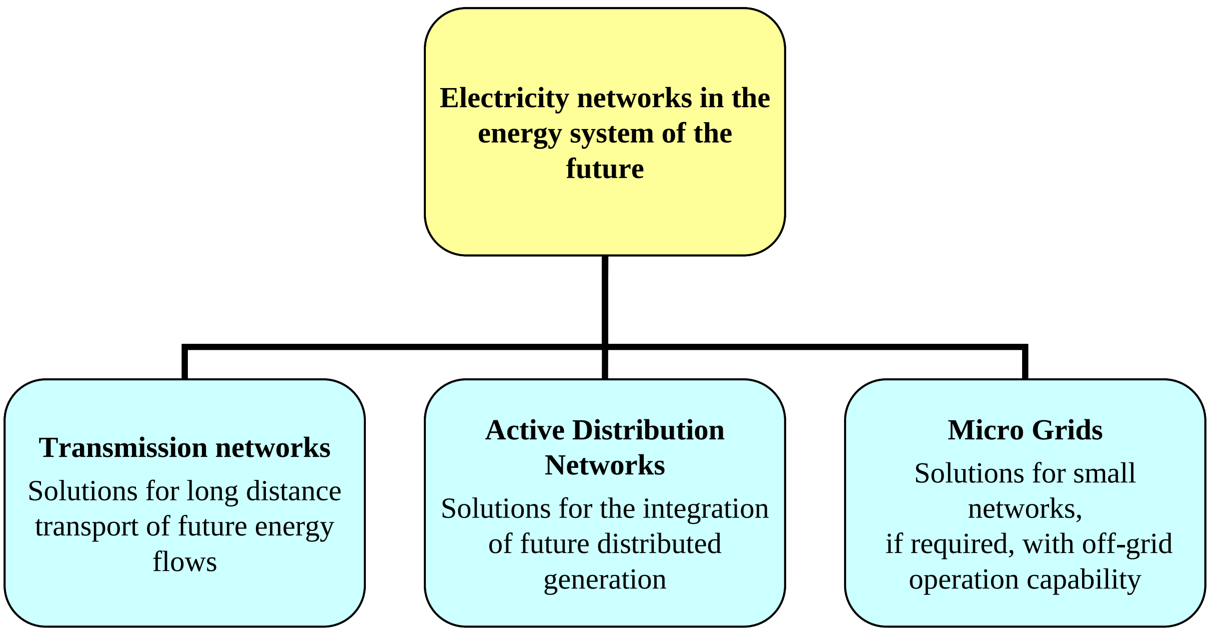

Figure 1.1: Overview on electricity networks in the energy system of the future

Active distribution networks refer to a network-operational approach to make best possible use of available infrastructure. In an active distribution network, controllable components - controllable generation units as well as loads and power storage devices - are deployed under the coordination of a distribution network management system to optimise the use of existing infrastructure. Thus, an active distribution network implies that the network operator has the opportunity to actively involve both embedded generators and consumers in operating his network through information and communication systems. This means that in an active distribution network – depending on demand and supply of energy – only certain embedded generators or certain embedded generators together with consumers are actively participating in network operations. Hence, active distribution networks set the realisation of an overall stronger and more efficient use of distributed energy resources, while at the same time complying with prevailing power quality and security standards.

This report sets out the prevailing standard network response scenario and develops the alternative response scenario to cope with increasing penetration of DG/RES-E. It identifies incentives for DSOs, DG operators as well as consumers that are to foster the transition from the standard to the alternative response scenario.

Objective of this study is to develop policy and regulatory recommendations to implement the most cost-efficient future network infrastructure and market design. As investments in networks are carried out for a long period of time, measures taken now will have impact on the cost development of networks and finally the electricity costs for decades to come. The development of different market places and the way DG/RES can participate here also will play a role in how optimally the integration of these sources will take place for the electricity system as a whole.

This report starts with three introductory chapters, formulating a vision on future smart grids, and discussing the issues of the grid boundaries and active network management. This is followed by a discussion of regulatory issues in five case study countries.

2 THE FUTURE VISION OF SMART GRIDS

2.1 Definition of a Smart Grid

The need for reduction of CO_2 emissions, decrease of energy imports and decrease of the use of finite fossil fuels result in the need for large investments and a number of innovative technical solutions in the context of power grids. The share of DG/RES in today's power systems has risen to a critical point, so that in some regions it is no longer possible to treat distributed generation as "negative load". But not only the additional generation from DG/RES puts the power grid to its limits; it is also the rising energy demand.

The traditional answer to these developments would be to build a stronger power grid. That would imply the reinforcement of transmission and distribution lines, and also the building of new lines. This "aluminium" solution comes often at a higher price than power grid operators or even society is able or willing to pay. Hence, "smart" solutions are required that make optimal use of existing infrastructure and can offer further additional functionality, that cannot be realized with a traditional power grid.

Thus, several initiatives on national and international level[1] address the topic of a common smart grid understanding and possible future prospects. Such a common definition e.g. could be formulated comparably to the one stated by the National Technology Platform – Smart Grids Austria as follows:

"Smart Grids are power grids, with a coordinated management based on bi-directional communication between grid components, generators, energy storages and consumers to enable an energy-efficient and cost-effective system operation that is ready for future challenges of the energy system."

The term "smart power grid" in this context serves as the umbrella for a harmonized and coordinated application of such new technical solutions, which heavily rely on information and communication technology (see Figure 2.1)

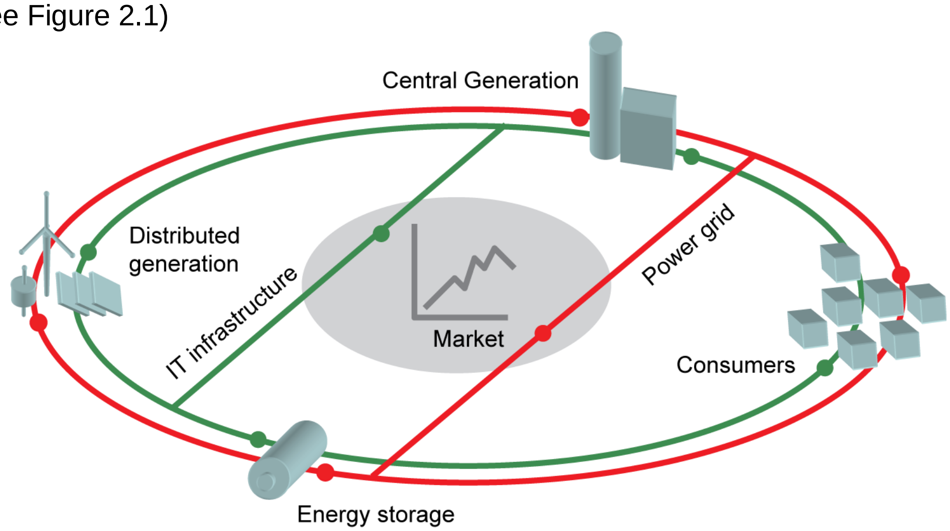

Figure 2.1: Definition Picture of a Smart Grid. (Source: National Technology Platform - Smart Grids Austria; www.smartgrids.at)

[1] Recently the "Technology Platform on Smart Grids" has been implemented within the 7th Framework Programme of the European Commission trying to bundle several activities, industries and stakeholders in this field (see www.smartgrids.eu). Also on national level in different EU Member States corresponding research programmes have been implemented (see e.g. www.smartgrids.at)

2.2 The role of Active Distribution Grids

For many decades the electricity system has been driven by the paradigm that most of the electricity is generated in large centralised power plants,[2] transported to the consumption areas through *Extra High Voltage (EHV)* transmission grids, and delivered to the consumers through passive distribution grids that involves a *High Voltage (HV)*, *Medium Voltage (MV)* and *Low Voltage (LV)* network infrastructure (see Auer et al (2005)). In this context, the rational for splitting the electricity grid infrastructure into separate transmission and distribution grids has been the following:

- Transmission grids consist of high voltage (typically > 60-150 kV)[3] power lines designed to transfer bulk power from major generation areas to demand centres over long distances. In general, the larger the voltage is, the larger the transfer capacity of transmission grids. Only the largest industrial customers are connected to the transmission grid directly. Transmission systems have been designed to be extremely robust with built-in redundancy, i.e. the transmission system can continue to fulfil its function by alternative routing and generation in the event of several simultaneous failures of the network. In liberalised electricity markets they are operated by "Transmission System Operators" (TSOs) or "Independent System Operators" (ISOs), which are usually independent and unbundled entities operating the transmission system and being also responsible for investments into network reinforcements and extensions (but transmission grids are also subject to regulatory control).
- Distribution grids are typically at voltage levels less than 60-150 kV, responsible for the connection of consumers at smaller distances. Furthermore, distribution grids are less robust than transmission systems, i.e. reliability decreases as voltage level decreases. E.g., in practise a connection at the 30 kV level could, on average, expect to lose only a few minutes of connection per year, whereas a connection at 230 V level for a domestic consumer in a rural area would, on average, expect to lose at least an hour per year.

Up to now, there has been very little so-called "active" management of distribution grids. Rather, they have been designed and configured on the basis of extreme combinations of circumstances (e.g. maximum demand in conjunction with high ambient temperatures, which reduce the capacity of overhead lines) to ensure that even in extreme circumstances predefined technical limits are met and quality of supply is guaranteed for customers.
So distribution grids – being the result of technological and institutional development over many decades of the 20th century – are increasingly changing its architecture to enable the injection of dispersed and large-scale DG/RES generation on distribution grid level. Moreover, active distribution networks are characterised by novel concepts and interactions of several network users involved (e.g. generators, grid operators and consumers) on different scales and based on different conceptual models.[4]

The evolutionary changes of the distribution grids in terms of system design, development and network operation philosophy, however, are expected to be gradual and uneven. But it is supposed to be clear that the distribution networks evolve towards transmission-like architectures. This transition process may require several intermediate steps (see also L'Abbate et al (2008)):

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[2] One of the major benefits of big centralised power plants is the utilization of significant amounts of so-called „Economies of Scale" in electricity generation

[3] Note, there is no common definition and strict voltage level separating the transmission and distribution grids in different regions worldwide. E.g., in Europe the voltage range from 60-150 kV separates the transmission and distribution grids, depending on the synchronised system within Europe.

[4] However, a clear picture does not exist at present about the most promising smart grid concepts to be implemented in the future. Scientific research and technological development in this context are still in a premature phase.

- In a first step, the implementation of new and advanced information, communication, control and data management systems is supposed to be a precondition to move from the traditional approach of DG/RES connection (`fit and forget'; see Figure 2.2a below) to more "active" distribution network operation (Figure 2.2b) supporting also the implementation of future advanced concepts like micro-grids (Figure 2.2c) or virtual power plants (Figure 2.2d). Both of these latter concepts may need the utilization of advanced solutions such as information and communication technologies (ICT) and flexible controlling devices (FACTS).[5] Moreover, further steps of complexity describe the implementation of corresponding devices that enable the management of bidirectional load and information flows. The implementation on distribution grid level is accompanied by further upgrades of protection devices and the implementation of new software and hardware (i.e. power electronics-based) technologies for more flexible system control. In the following Figures 2.2 the gradual evolution of future distribution network architectures is presented in detail.

Figure 3a. Traditional Distribution Grids Scheme

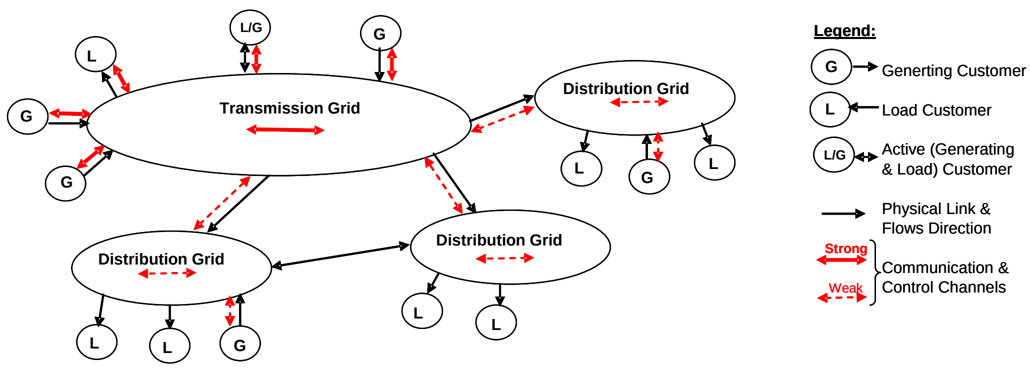
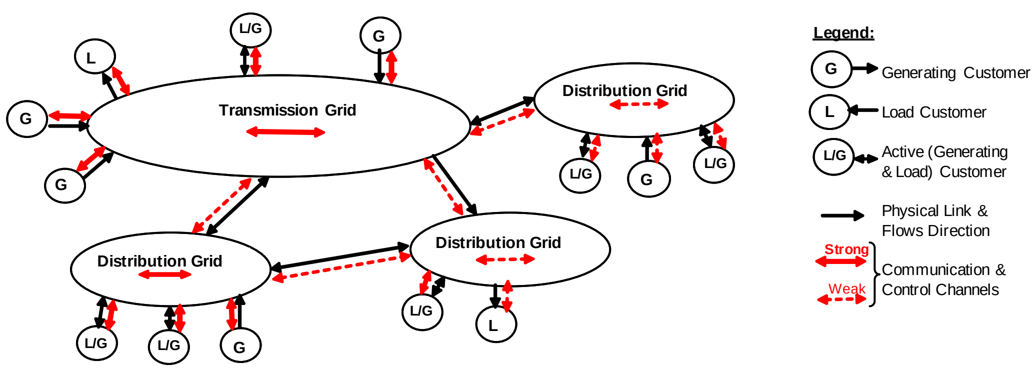
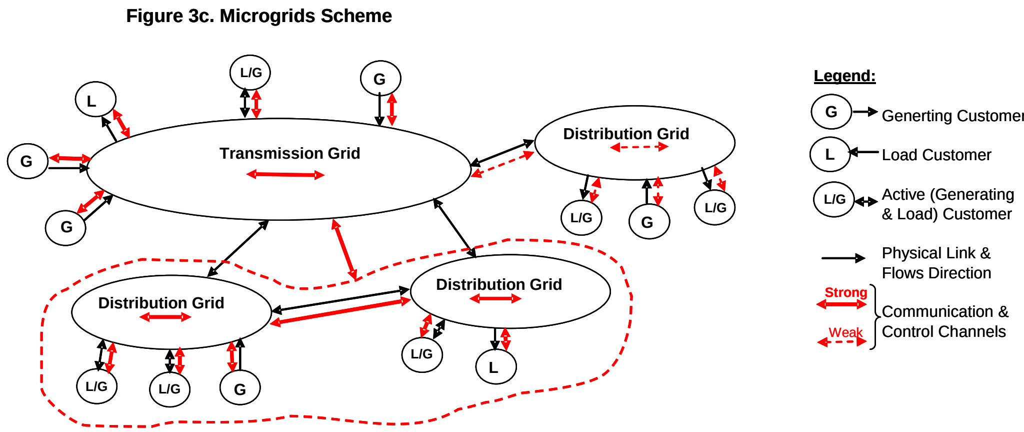


Figure 3b. Active Distribution Grids Scheme



[5] The acronym FACTS stands for Flexible Alternating Current Transmission Systems



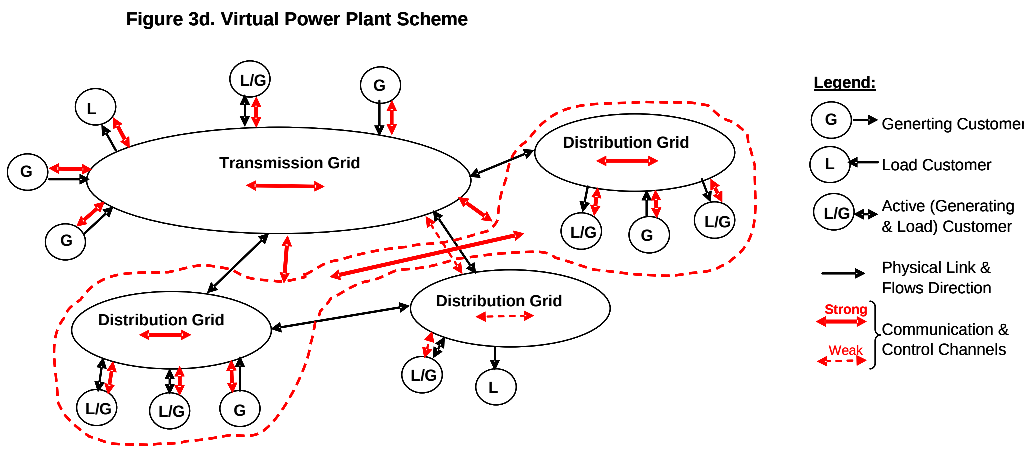


Figure 2.2: Different configurations of future distribution grid architectures: Fig. 3a (numbering from the original source): Traditional distribution grids; Fig. 3b: Active distribution grids; Fig. 3c: Micro-grids;[6] Fig. 3d: Virtual Power Plants.[7] Source: L'Abbate et al (2008)

[6] In general, a micro-grid is a part of a distribution network containing DG/RES sources, together with local storage devices and controllable loads. It can be regarded as a controlled entity which can be operated as a single aggregated load or generator, eventually providing network support and services. Micro-grids generally have a total installed capacity between few hundred kW and a few hundred MW. The unique feature of micro-grids is that, although they operate mostly connected to the distribution network, they can be automatically disconnected by intentional islanding in case of faults affecting the upstream network. Then, micro-grids having sufficient generation and storage resources can ensure power supply to local customers. After a fault has been cleared and the upstream network operation restored, micro-grids can be resynchronised to the rest of the system. Additionally, the islanding procedure could also allow a micro-grid to support 'black start' in case of a widespread system outage.

[7] The Virtual Power Plant (VPP) is a decentralised energy management system tasked to aggregate different small generators for the purpose of energy trading and providing system support services. The VPP concept is not itself a new technology, but a scheme to combine DG/RES and storage and exploit the technical and economic synergies between the systems' components. This aggregation is not necessarily pursued by physically connecting the different power plants but by interlinking them via information and communication technologies. For this reason, the result is a virtual power plant, which may then be a multi-fuel, multi-location and multi-owned power station. A VPP balances required and available power in identified areas, based on offline schedules for DG/RES generation, storage, demand-side management capabilities and contractual power exchanges. For a grid operator or energy trader, buying energy or ancillary services from a VPP is equivalent to purchasing from a conventional power plant.

- Future concepts going beyond those configurations presented in Figure 2.2 may rely on fully automated, active, smart and intelligent operation of distribution grids. This means that fully autonomous "cells" have to be implemented on distribution grid level. More precisely, the distribution system may be subdivided in more subsystems. Eventually, each subsystem has to be able to balance supply and demand effectively (i.e. be self-sufficient) for a twofold reason: (i) to be able to disconnect from the interconnected system and continue running in case of large and widespread disruptions and (ii) to reduce the burden (in terms of control actions and losses) on the upstream transmission systems. In a fully autonomous cell concept on distribution grid level also comprehensive "communication" between the transmission and distribution grid is essential for requesting the cell to provide black-start capability support and restore the service after a fault. In practise, Denmark has been the first country implementing a "cell concept" like that (see e.g. Eriksen/Orth (2008), L'Abbate et al (2008)).

3 Active Network Management

3.1 Definition

In the past, electricity generation was mainly from centrally scheduled large-scale power plants. Aggregate centralised generation followed aggregate demand for electricity by all the connected customers. With the current trend of the growing shares of distributed generation at all voltage levels in the grid, and increased possibilities for flexible loads, the whole electricity system is undergoing a gradual evolution into a much more integrated and interactive system with an important role for ICT enabling a more optimal operation of all major components in the system. We are already in the early stages in the development of 'smarter' grids.

To some extent, transmission networks have always been operated actively. Reconfiguration of the network and rescheduling of power plants are being used to react on changing situations relating to availability of network components and power plants, and to the load being different than forecasted. As a consequence, a higher level of network utilization can be achieved, resulting in less costly transmission grids.

Currently, distribution networks are operated in a passive way and are designed with a philosophy which can be characterised as: 'fit and forget'. Lines, cables and transformers are usually dimensioned with reserve capacity to allow for (decades of) load growth. Almost no control of generation or loads in distribution networks takes place. The fundamental question - similar to the situation with transmission grids - is if a more active management of distribution grids would be possible? Would it be beneficial for the utilisation of the networks, resulting in lower overall costs? The Improgres project does not deal with important technical grid issues such as safety and reliability. Therefore, the assessment of Active Network Management (ANM) is limited to the integration of distributed generation and demand response in a more active operation of networks, focusing on benefits in the form of reduced investments in network enhancement, including the effects on generation costs and taking into account external effects.

3.2 ANM in grids with small numbers of actors: the case of the Netherlands

High electricity prices in recent years have led to a rapid growth of new CHP units in greenhouses. This was not foreseen by the DSO and the TSO, resulting in a situation of local generation overcapacity compared to the grid capacity in Westland, an agricultural area near Rotterdam. During some hours per day, congestion takes place in this region. This is a temporary situation (expected to last for only about a year) until grid reinforcements have been implemented. A congestion management system is developed as a system to allocate the scarce transport capacity over the different distributed generators. It can act as an example as to how active network management could be organised in the future. An important difference with ANM is the fact that in Westland, the DSO is relieved only temporarily of its obligation to transport all the electricity supplied. For Active Network Management as analysed in the IMPROGRES project for the case of North Holland, we assume a continuous relieve of the transport obligation: the DSO is allowed to defer network enhancements indefinitely, and is allowed to maintain network conditions in which not all generation can be transported (or all load can be met) at all times.

Congestion management in Westland
Operators of new CHP units within the congestion zone are obliged to formulate a plan for generation for the coming day and submit this to their Program Responsible Party[8]. Additionally they have to formulate bids for paying the TSO for not producing the electricity that they have sold already on the market. When congestion is expected, the network operator takes over the production obligation from the CHP operator, and compensates this by obtaining additional generation from outside the congestion zone[9]. The TSO pays generators outside the congestion area to produce more and receives (a smaller amount) from some CHP operators in the congestion area for not producing. This so-called 'redispatch' always results in a cost for the network operator.

Potential network cost savings for the DSO due to Active Network Management
The IMPROGRES case study area Kop of North Holland is a windy area, 50 km north of Amsterdam, with many greenhouse expansion plans. Considering the distribution grid in the Kop of North Holland, the assessment is limited to a few options with a large potential. Wind curtailment is the temporary reduction of the output of wind farms. A number of scenarios were defined for 2020 with different levels of DG penetration (See IMPROGRES deliverables D5 and D6: [Olmos et al, 2009, and Cossent et al, 2009]). For the 2020 scenario with high penetration of distributed generation, a reduction of 200 MW at times of maximum wind output (500 MW) is our estimate for the maximum potential for wind curtailment. CHP units are assumed to reduce output by 30%, equivalent to 265 MW, at times of peak generation. Electricity demand for lighting in greenhouses can be shifted by a few hours to different hours of the night (potential 100 MW). With the network models of Comillas as described in [Cossent et al., 2009], applying these three measures together will lead to about 30% lower network cost. On an annual basis the total network cost savings (including maintenance and losses) of active network management is calculated to be 10.5 M€/year. When treating the three options on an equal basis, the annual network cost savings amount to 18,500 € per year per MW of deployed ANM options.

Foregone benefits of CHP operators due to ANM
Agricultural CHP units in the Netherlands typically generate about 4000 MWh electricity per year per MW of installed capacity. Most of this is used onsite, and on average about 1500 MWh per year per MW is exported and fed into the grid, primarily during the peak hours. Taking into account the value of the heat, the variable cost of electricity generation (in 2007) was about 45 €/MWh. Typical prices on the day ahead market for the peak hours are around 75 €/MWh. Not producing at full capacity during 1500 peak hours a year therefore implies foregone benefits to the CHP operator in electricity sales of 45,000 €/year per MW of peak power reduction. When the CHP operator has already sold his electricity production, he would be willing to pay to the DSO at most 45 €/MWh (due to the savings on variable costs). For that price the operator is indifferent in the decision to produce or not. For lower prices he will make an additional profit. Cost for the DSO are therefore at least 45,000 €/year per MW of peak generation reduction through CHP units only. This compares unfavourable with the much lower level of the benefits of network investment deferral of 18,500 €/MW/year.

From this simplified cost-benefit analysis of Active Network Management with CHP units, the following can be concluded. If the network operator has to rely on CHP units that can reduce their output for many hours per year (1500 hours in the example above), there is no viable business case for the DSO

[8] A Programme (or Balancing) Responsible Party is a commercial entity (e.g an electricity producer, retailer or trader) which formulates programmes for planned electricity generation and load and have to submit these programmes to the TSO. After real time the PRP will be charged an imbalance charge for any deviation from the submitted programme.
[9] In this temporary small scale mechanism in Westland, the TSO uses its market for regulation and reserve power for the incremental bids.

to have the CHP units contribute to network cost savings. Only when a contribution from CHP units is required for a much shorter period of time (a few hundred hours per year or less), there appears to be a potential for a viable business case. This situation would occur when CHP power output reduction is only needed in periods of high wind power output.

When a DSO is more or less forced to rely on a small number of installations to reduce their output, there is a serious threat of gaming and misuse of market power. This can be limited somewhat by creating as much competition as possible by limiting the contribution from these units to a level that is substantially below their technical potential.

Limiting ANM only to export of excess generation to the grid during high wind power output, and taking into account a reduction of the requested contribution to limit market power, the actual potential for ANM is estimated to be only about 100 MW instead of the technical potential of 565 MW. The resulting estimated cost savings of 100 MW of ANM options are expected to be about 5% of network investment cost.

4 ECONOMIC SIGNALS FOR IMPROVED NETWORK INTEGRATION OF DG

The integration of DG in distribution networks is often considered as suboptimal, both with respect to the level and distribution of network costs among network users. In order to improve network integration, existing barriers for network integration as well as opportunities for full realization of the cost saving potential of new technologies are identified. Section 3.1 deals with the importance of full network cost recovery for DSOs in light of the changing network cost structures due to the energy transition taking place. Section 3.2 highlights the value of innovation incentives to promote a level playing field for investments in conventional and new network technologies. Section 3.3 provides measures to speed up network planning for getting DG earlier on stream without increasing network costs substantially. Section 3.4 discusses different network calculation approaches and their merits. Finally, Section 3.5 focuses on demand response as a way to increase flexibility of power systems with much intermittent DG. In this way this chapter aims to provide an overall introduction for the discussion of the regulatory issues in five case study countries in the next chapters.

4.1 Network cost recovery

Electricity grids are capital intensive infrastructure elements being characterized by the grid assets' lifetime of many decades. Once investments are made, they are effectively sunk. It makes grid assets vulnerable to changes in regulatory conditions which could prevent or hinder cost recovery. Therefore, long term investments into the grid infrastructure require stable regulatory conditions. Distribution grid operators are reluctant to facilitate large-scale integration of DG/RES generation facilities into their distribution grids, unless the corresponding extra cost drivers in this context are understood, quantified and – most important – cost recovery is guaranteed in network regulation.

Recovery of costs is usually based on a number of cost drivers like for instance the number of customers, units of electricity distributed, peak demand and network length (Jamasb and Pollitt, 2001; Jansen et al., 2007). However, cost drivers change due to the energy transition. Many countries face substantial increases in generation capacity, increase in the unevenness of location of supply and demand, and increase in the regional excess of energy produced at some times. This requires changes in the proportions between cost factors as well as the addition of new cost drivers like (net) electricity produced by DG in regular productivity estimates (De Joode et al., 2007). Therefore, regulators should closely monitor cost developments and adjust them when appropriate.

4.2 Network innovation

Currently, 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 to decrease the monopoly profits of network operators. In order to prevent that gains in short term efficiency come at the expense of long term efficiency, also long-term efficiency issues like quality of supply and innovation should be duly taken into account in network regulation. Concerning quality of supply, therefore network operators usually are allowed additional funding through a quality (Q or K) factor for guaranteeing quality of supply. Likewise, it is also warranted to treat innovation as a special aspect in regulation, for at least two reasons.

Firstly, existing regulation declines DSOs' inclination for investments in innovative network solutions. Since investments in innovative measures and devices are by definition more risky than investments in more conventional measures and devices, the return on investments for the former type of investments need to be higher as well. However, the strong focus of current regulation on short term cost reduction combined with short regulatory periods of three to five years, offers limited possibilities to realize full long term benefits of innovative investments; the higher benefit of the latter are often already (partly) captured by regulation after three to five years, skimming the net benefits and deteriorating business cases of new risky investments.

Secondly, benefits of ANM type of innovations are only partly experienced by DSOs, part of the benefits flow to other parties in the electricity value chain like generators, suppliers and loads. When DSOs do not experience full benefits of investments in ANM while they obtain full benefits of conventional 'fit-and-forget' network solutions, this affects their trade-off between investments in conventional network solutions and ANM. Consequently, in a number of cases they will be biased to invest in conventional grid solutions instead of ANM. Therefore, part of the smart grids projects will not be realized without innovation incentives although these are preferable for the country as a whole. Network innovation incentives can be either input based mechanisms which link a remuneration to the *efforts* of network operators or output based mechanisms which link the remuneration to the *results* of those efforts i.e. ensuring an efficient and reliable energy supply. Preferably, network innovation incentives should be output based in order to leave the decision whether to invest in a specific technology completely to the network operators themselves. Instead, output based regulation can be aimed at ensuring an efficient and reliable energy supply, both in the short and long term. However, an output based regulation method may not always be possible due to the large number of factors that influence DSO performance including network topology choices made in the past, network characteristics (meshed or radial, urban or rural), DG penetration level, DG concentration etc.
One possible indicator could be distribution network capacity utilization which provides an indication of the actual availability of network capacity with respect to a certain standard value.

4.3 Network planning

In some countries there are queues for the connection of new generation capacity, slowing down the connection of new distributed generation amongst others. In order to be able to integrate substantial shares of DG in short notice, current investment planning policy should be improved. Brattle (2007) indicates a number of possibilities with high potential to improve the current situation;

- *Publish information on the amount of connection capacity available at different parts of the network*, preferably on a substation by substation basis. This improves transparency and therefore the investment climate.
- *Implement project milestones in the planning process with cancellation fees*. Project milestones may concern procurement of planning permission by the generator and/or progress in securing equipment or fuel delivery, among others. Cancellation fees can be tuned to the connection costs including the cost of required grid reinforcements behind the connection point. In that way, cancellation fees vary by location and are higher in congested areas. Consequently, investors are forced to be more carefully in their connection requests, especially at places with high network reinforcement and therefore social costs. Likewise, also the DSO should be subject to milestones in order to complete certain tasks within time.

- The permit process for network expansion is often started only after receiving applications for new capacity. Required time for network expansion can be reduced by starting the permit process for likely network reinforcements prior to receiving those applications. For the time being*, therefore it is advised to start the permit process for network expansion prior to receiving those applications*. In case this measure proves to be insufficient, constructing connections and concomitant grid reinforcements prior to applications for connections might be considered as an option.

4.4 Network charging (network cost allocation)

When integrating significant amounts of DG/RES generation technologies into the existing electricity systems, required grid reinforcement and extension measures raise the question where to allocate the corresponding extra cost. In a meshed grid infrastructure the allocation of grid reinforcement and extension measures and corresponding cost to a newly integrated DG/RES generation facility is ambiguous, see Figure 4.1.[10]

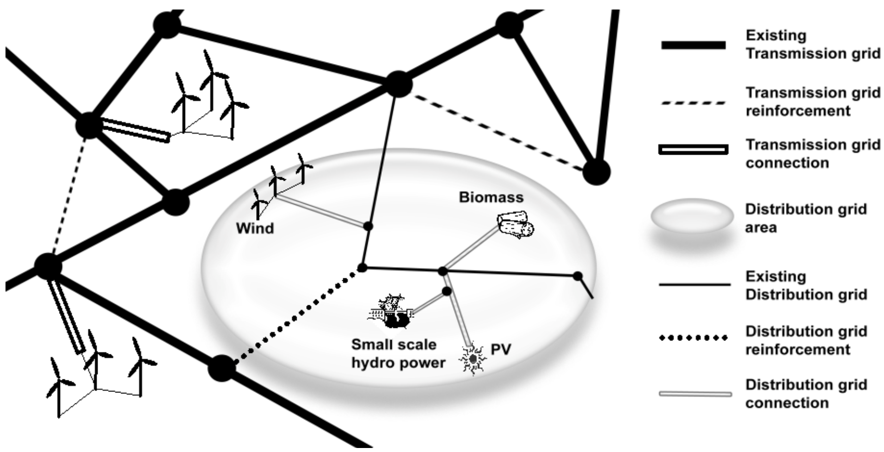


Figure 4.1 Grid connections and grid reinforcements caused by large-scale DG/RES integration. Source: Auer (2006)

The core problem in this context is that any changes in a meshed grid infrastructure (e.g. also disconnection of a large industrial customer) will change the load flows in the electricity system. Therefore, the status quo of load flows in an electricity system is also just a snapshot of the existing randomization of generation and load centres. Moreover, the status quo as well as changes of load flows have a variety of dimensions, as there are e.g. changes in the geographic distribution of generation and load centres, bottlenecks in peaking periods or commercial power trading activities. Therefore, the allocation of load flow changes and, subsequently, grid reinforcement and extension measures to the integration of a single new DG/RES generation facility is ambiguous. However, at the same time it is clear that generation considerably contributes to network reinforcements and associated network costs. Assuming that network costs due to RES/DG are fully remunerated to DSOs by inclusion in the allowed expenditures (see Section 3.1 for some notions regarding this assumption), DSO' network costs can be fully recovered from the network users i.e. both generation and (demand) load.

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

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.

Connection charges

Two distinct approaches of calculating connection charges can be distinguished: deep and shallow connection charges;

- Deep connection charges: Based on this approach, the DG/RES developer bears several extra grid-infrastructure related DG/RES integration cost (i.e. grid connection as well as grid reinforcement/extension cost) and includes them into the total DG/RES project cost.
- Shallow connection charges: The shallow approach characterises the situation where the DG/RES developer bears the grid connection cost, but not the grid reinforcement/extension cost (they are socialised in the use-of-system (UoS) charges).

Deep and shallow connection charges have both their merits and demerits (see Scheepers (2004), Knight et al. (2005), DTI (2006), Auer (2006), Vogel (2008). In general, the deep DG/RES 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 vexing challenges;

- The computation of proper deep connection cost (and, subsequently, connection charges to DG/RES generators) is very difficult because it is impossible to correctly foresee the future set of entrants on the distribution grid, their needs (e.g. connection capacity) and the values they place on each location.[11] 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 oversizing connection capacity and hence prescribing overcharges for connection of DG/RES generators.
- In almost all cases the situation described above is getting even more complex, since DG/RES connection inquiries are rather sequential in time than simultaneously. 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 cost 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 distribution grid operator and rebating it to the first entrant).[12]

Although deep DG/RES integration policies provide strong locational signals, compared to deep connection charging, shallow connection charging has at least the following advantages;

[11] Only in theory the distribution grid operator can optimally plan the distribution network 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 cost of several new DG/RES generators on distribution grid level.

[12] In general, DG/RES generators and, therefore, also the first entrants are likely to be less well-informed than the distribution grid operator about the connection capacity needed and corresponding cost. Moreover, the first entrant is usually also 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 would be an advantage if distribution 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 distribution 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 connection charges avoid large upfront costs for RES-E/DG, which would discriminate against DG as compared to centralised generation technologies.
- Shallow connection charges are more straightforward to calculate since they concern only connection costs and do not require forward looking costs calculations. As a result negotiations about the fair deep connection cost component are avoided, and charges are more transparent and acceptable for different parties involved.
- Shallow connection charges are more transparent and therefore an important instrument to provide fair and non-discriminatory network access to the network for different kinds of generators, including small renewable generation units.
- The first mover problem disappears since the first entrant is charged only for the cost of the connection. Moreover, from the distribution grid operator's point-of-view the risk of cost remuneration in case of over-sizing connection capacity (e.g. for providing the basis for synergies for later DG/RES connections at the same location) disappears since grid reinforcement and upgrading cost are socialised in the UoS charges and, therefore, are directly borne by the network users.

As a conclusion, shallow connection charges are advised to be implemented.

Use of system charges

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 covered in some way. Therefore, Use of system (UoS) charges are often introduced to spread out the remaining network (reinforcement) costs. Currently, UoS charges are in most countries only levied upon consumers. Provided the contribution of generators to network costs as outlined in this Section before, also generators should receive an incentive to take into account the network costs that the system will incur due to their operation. Therefore, the introduction of cost-reflective use of system charges for generators is deemed useful. Coordinated implementation of this measure, at least in the North-West European market but preferably at wider European level, seems necessary since an uneven implementation of UoS charges for generators might result in an uneven level playing field for generators across the EU.[13]

UoS charges can be either full capacity- (kW) or energy-based (kWh) or a mix of both. On the one hand, in case UoS charges are fully capacity-based (kW) this accounts for the fact that the required network capacity for network users is mainly capacity based; DSOs have to guarantee the connection and transport of the energy produced at full capacity, taking into account existing complementarities between production patterns as well as the interaction between production and consumption patterns. On the other hand, in case UoS charges are fully energy-based (kWh), this accounts for the fact that network costs are not only related to investments in additional network capacity, but also to O&M costs like energy losses which are related to the actual amount of energy transported through the network. However, with fully energy-based UoS charges energy sources with low load factors do have to pay only a part of the network costs they induce to the system which means that network costs are redistributed upon energy sources with high load factors. At least from a cost-causality point of view this is not preferable.[14] Consequently, *UoS charges should preferably be dependent on both kW production capacity and kWh energy produced, with a higher weight given to the amount of kW capacity of the producers.*

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[13] This is in line with recommendations provided in earlier projects like Sustelnet (Scheepers, 2004), DG-GRID (Skytte and Ropenus (2005), ELEP (Knight et al., 2005) and RESPOND (Van der Welle et al., 2009).

[14] Whether or not redistribution of network costs through UoS charges is favourable is subject to political decisions.

Furthermore, since the network impacts of RES-E/DG differ to time and location, efficient integration of renewable sources can in theory be improved by temporal and locational differentiation of UoS charges. Time differentiation in Use of System charges is more practical to implement than locational signals. Signals that provide information on what hours of the day to shift generation or loads can be beneficial in postponing network investments. In this way, generators receive an incentive to behave in accordance with system needs when deploying their units. Many generators already have the possibility to react to variable network charging, since they already dispose of smart metering.

4.5 Demand response

The increasing supply from intermittent renewable energy sources adds one additional source of stochasticity to the generation mix, which lowers the flexibility of generation to follow demand and increases system integration costs, especially distribution network costs. In order to compensate for this cost increase, demand could be made more responsive to system conditions. Shifting load from peak to off-peak periods lowers not only demand for generation peak capacity, but also demand for additional network capacity. As marginal costs of reducing or increasing demand are generally deemed lower than marginal costs of additional generation and network capacity, it is more efficient to reduce demand instead of deploying additional generation and network capacity to enlarge the flexibility and controllability of system operation.

Currently, demand response is nearly non-existent, due to the fact that very few customers have contracts which include some sort of real-time or near-real time price information. In order to increase the responsiveness of the demand side of the electricity system, in several Member States the roll-out of smart meters among low-voltage customers is ongoing. This should be accompanied by sending consumers price and/or volume signals, otherwise customers will probably not react. Price signals would constitute differentiated energy prices. Common schemes are time-of-use (TOU) prices, real-time pricing (RTP) or critical peak pricing (CPP). Volume signals are limitations on the consumption of specific loads during a certain time span through, for instance, interruptible contracts. Additionally, demand response programs ought to be defined and progressively implemented, starting with those customers that already have smart meters. It is important to carefully define the role of each of the agents involved, especially for the retailers. Home automation ought to be developed and promoted to harness the demand response potential to a larger extent. Evidently, the functionalities of the “smart meters” that are being installed should enable to endorse such applications.

5 REGULATORY STRATEGY FOR DENMARK

Denmark's electricity system is characterised by a large share of wind power and CHP generation. Integration of the latter has been achieved through a range of energy-specific legislation and regulatory measures adapted over decades. First the main characteristics of present and future integration of DG/RES in power markets and networks are addressed. Then, a closer look is taken at support schemes to promote certain generation technologies before turning to DSO regulation, demand response and network planning. The section ends by concluding that major parts of regulation should be maintained with the addition of elements in order to support the efficient localisation of new DG investment and to incorporate new and flexible load in network planning.

5.1 Integration of DG/RES in Networks and Markets

Electricity production in Denmark is primarily based on large central CHP plants, wind as well as small-scale decentralized CHP. A large fraction of wind and small-scale CHP generation has been connected to the distribution networks (60 kV or lower) until now. Decentralized CHP installations are predominantly based on natural gas, waste, biomass and biogas. The planning of onshore wind turbines is administered by the municipalities/local authorities, and there has been a tradition for local consumer ownership. In the past ten years, the erection of offshore wind farms, which by contrast are connected directly to the transmission system, was promoted through the adoption of tendering procedures. In 2009, offshore wind capacity amounted to 631 MW (ENSa). In 2007, a plan identifying appropriate sites for offshore turbines was issued for 23 wind farms with an aggregate capacity of 4,600 MW that may produce approximately half of Danish electricity consumption under favorable wind conditions (ENSb). Hence, the challenge of integrating additional wind capacity will particularly arise at the transmission rather than at the distribution level.

The expansion of other DG technologies into the distribution grids is expected to be very limited in the future up to 2020. High shares of RES and DG have already been integrated in Denmark without big difficulties. The 2020 sustainability targets for Denmark and the Danish renewable electricity (RES-E) expansion plans indicate that the DG share in 2020 could reach 35% of total electricity produced.

Impacts on *distribution networks* result mainly from increased connection of onshore wind and increasingly flexible CHP to the medium voltage networks (60 kV) in rural areas. In recent years, some 2000 onshore wind turbines (mostly 200-300 kW) have been scrapped and replaced by larger and more modern wind turbines which exhibit more favourable operational characteristics for network operation. This repowering has increased the capacity and generation in distribution grids, but has not caused significant problems in DSO grids in Denmark. Electricity production based on PV and micro-CHP grows very slowly and will not have a decisive impact on distribution networks before 2020.

In the wholesale and balancing power markets, most DG/RES units participate through aggregators. The participation by DG/RES in these markets are not seen as affecting the DSO grids significantly, but this might become an issue if participation in regulating markets becomes widespread among DG and the amount of DG in the grid becomes large enough to require more curtailment. For the moment this is not relevant in the Danish DSO grids.

5.2 Support Mechanisms

In Denmark for many technologies there has been a transition from the classical feed-in tariff to price premiums as the predominant type of promotion scheme. Originally, many legal provisions governing support were included in the Electricity Supply Act (*Elforsyningsloven*, 1999). Since December 2008, a

new law on the support of renewable energy has been in force (*Lov om fremme af vedvarende energi*, VE 1392) laying down support schemes and levels for the individual technologies as well as access conditions and administrative procedures.
Feed-in premiums are applied for *onshore wind power*. In the last decade, the price premium for new onshore wind turbines has been increased significantly. For onshore wind turbines that have been connected to the grid after February 2008, the premium amounts to 3.4 ct/kWh. Furthermore, operators of onshore wind installations receive a balancing compensation equivalent to 0.3 ct/kWh since they are responsible for their balancing costs themselves. Old onshore wind turbines are financed by a fixed feed-in tariff. The support for *offshore wind farms* is allocated by means of a tendering procedure. Offshore wind operators that have been awarded the contract then obtain a guaranteed feed-in tariff for a pre-specified amount of full-load hours. Similarly to the development of price premiums for onshore wind power, during the last tender round the feed-in tariff levels have been increased compared to previous tenders. *PV* support is based on net metering. Only limited support exists for solar heating in new dwellings (up to 20% subject to a number of criteria). For *CHP* the picture is mixed. Since 2007 all thermal generators above 5 MW have been participating in the spot and balancing markets. Market participation for smaller generators is organised by commercial aggregators that are financial entities that operate on both the spot and regulating power markets and aggregate production originating from DG and small-scale CHP. Small-scale CHP units with a capacity of less than 5 MW, mostly built in the 1990s, had to choose between an annual production subsidy (fixed lump sum payment) and a priority dispatch regime with a fixed feed-in tariff. The advantage of the former is that small-scale CHP units are given an incentive not to generate electricity when wind generation is abundant and prices are very low. Under the priority dispatch regime, CHP does not receive this incentive and consequently will not take into account the electricity demand in its production decisions; this is detrimental to market flexibility and system costs. The change from a fixed feed-in tariff to feed-in premiums for existing small-size and medium-size CHP installations has improved the efficiency and functioning of the market as CHP units became exposed to market prices with a high time differentiation.
At present, support schemes in Denmark are not locationally differentiated. There is also no differentiation of support according to voltage levels, but only a differentiation per type of DG/RES source (lowest for wind, higher for biomass, highest for PV).
The costs for the support scheme remunerations are socialized via TSO tariffs. The latter includes a so-called PSO element (public service obligation) for the promotion of environmentally friendly energy that is paid for by consumers. A special characteristic of the PSO element is that it also covers expenses for research and innovation projects.

5.3 DSO Regulation: Connection and Use of System Charges

In Denmark there is one TSO, ten operators of the regional transmissions networks (132/150 kV and some 60 kV) and 101 distribution network companies (by the end of 2007). The TSO owns and operates the 400 kV network as well as part of the 132/150 kV network and also operates all other networks of > 100 kV reimbursing the owners. The TSO has an obligation to acquire networks of 100-200 kV (in practice > 100 kV) put out for sale (Danish Energy Regulatory Authority/ERGEG, 2008).
The TSO Energinet.dk is state-owned. As for the transmission level, connection and Use of System (UoS) charges are levied on both generators and load, although the charges for generators are very limited. All generators - except those with priority access - pay the same network tariff, which is 0.0536 c€ per kWh in West and 0.0268 c€ per kWh in East Denmark (Q1 2009). No network costs are allocated to generators with priority access (CHP units smaller than 5 MW which do not face market pric-

es), which means that they do not pay any network charge at all. Charges for load are cascaded through the DSO to the loads (Danish Energy Regulatory Authority/ERGEG, 2008).

With regard to the distribution level, ownership of network assets by DSOs is a requirement of the Electricity Supply Act. The 101 DSOs are legally and increasingly functional unbundled. Currently a movement to ownership unbundling has become visible; soon the majority of DSOs will have sold off their minority holdings in generation, although there is no restriction on RES-E/DG ownership for DSOs as long as it is a minor activity.
Costs for operating and investing in distribution networks by DSOs can be passed on to generators and consumers through two kinds of network charges; connection charges and use-of-system charges.
Each distribution network company has its own network tariffs. This means that there are around 100 different sets of network tariffs. Only the methodologies of setting the tariffs are approved ex-ante by the Danish Energy Regulatory Authority. Distribution network companies pay for transmission network tariffs to Energinet.dk and to regional transmission companies. Thus, distribution network tariffs include these payments as a component in the distribution tariff. All Danish DSOs are subject to an incentive regulation defining an allowed revenue cap. The system has not been functionally in place over a longer time and has experienced major revisions so that final conclusions can hardly be drawn. However, it should be ensured that the system allows higher revenue caps for DSOs in regions where a high share of DG/RES units is installed.

Connection charges for DG/RES units in Denmark can be classified as shallow. This has provided stable and transparent conditions for new investment, and shallow charges should hence be maintained. Use-of-system charges are paid both by consumers and generators in Denmark. No UoS charges are applied for wind and local CHP. However, the generator share of overall UoS income is comparatively small. Most DG/RES units are subject to an exemption clause because they have priority access, e.g. small CHP units and wind turbines. Consequently, investment decisions by RES generators are not influenced by network costs in the choice of their production location and in their production profile. This may be deemed inefficient if penetration of RES generators rises further.
In the future, there remains an option to consider use-of-system charges for DG in areas where there might be implications for the locational decision and the share of DG is high. Locational incentives could be given by a DSO payment or a reduction of connection charges if a generation unit with a typical generation profile is connected to a certain network node that induce lower costs in the network.

5.4 Demand Response and Smart Metering

In general, load is expected to grow very slowly in Denmark which results in an increase in DG generation relative to load. However, some possibilities for additional load exist. Both additional heat pumps and other electric heating devices and electric vehicles will provide additional load that is potentially flexible. These two categories of load might mitigate potential problems in distribution grids with a large share of DG, especially wind. The night excess generation can be balanced with additional load during night time. Planning and regulation should seek to ensure that DSOs integrate the additional load in planning so as to encourage its active contribution to flexibility.
With regard to DSO planning, it is important that the local implications of national policies to promote heat pumps and electric vehicles are integrated into network planning. In general, electric vehicles will add load where there are no problems with excess generation in DSO grids, but there might be positive impacts on transmission level constraints. For heat pumps and electric heating, emphasis should be put on allowing this first in areas with high wind penetration. In most cases, this will also be in areas

where there is less district heating and natural gas heating coverage. In all cases with additional demand, it is important that these residential demand categories are also equipped with metering and control equipment that can respond to price fluctuations. A low power market price is correlated to excess wind generation in local grids. Increased demand response might reduce problems with excess generation.

Finally, the DSO should be entitled to curtail part of the wind generation while paying compensation based on market prices (80-90% of wholesale price). The existing subsidy (premium) to the wind generator should still be provided for the curtailed wind by the nationwide PSO contribution.

5.5 Network Planning

Distribution network integration of future wind expansion will be moderate in Denmark. The majority of additional capacity will be offshore and connected at higher (transmission) levels. For distribution networks, although some pilot projects for the initial 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 and wide options for including investments related to renewables. Future network planning at the DSO level should integrate the expected DG investment and identify the most beneficial location of this in the local network.

Curtailment of wind generators in congested DSO grids should be integrated in regulation as an option to consider for the DSO instead of reinforcement. Compensation based on market prices should take place and if this proves to be cheaper the DSO it will also be a benefit for customers. In some cases the reinforcement to avoid a marginal and occasional curtailment is not worth it and might even prove unnecessary as more flexible or additional load might prevent it from happening in the future.

5.6 Conclusion

Based on the previous findings, the following conclusions for regulatory recommendations can be drawn:
The shallow connection charge approach provides a fair and transparent access treatment for DG investors and should be maintained. To account for the increased network cost induced by additional DG generation, it should be considered to supplement connection charges with UoS charges for generators in grids with a high share of DG/RES. However, these UoS charges for DG producers should not exceed the level of UoS charges that large conventional generators pay in order to ensure a level playing field between generators.

DSOs should be incentivised to provide locational signals to potential DG investment in the form of reduced connection charges or reduced UoS charges at certain locations where DG investment has a positive network impact.

Locational signals should not be included in the support schemes as location differentiated support. It is preferable to provide locational signals directly in network charges instead.

Anticipated future flexible and additional load should be incorporated in distribution network planning.

6 REGULATORY STRATEGY FOR GERMANY

6.1 Introduction

Germany has shown a strong growth rate in DG/RES development. While historically this is owed to a timely stable and economically favourable promotion mechanism, recent legislation strengthens transparency in the rules for DG/RES grid access and setting tariffs of grid related services.

For the future development a further rise in DG/RES generation is expected. The expansion of onshore wind power, PV, CHP (from natural gas, biogas) will lead to a rising impact on the distribution networks. Presently due to the high amount of wind energy in eastern and northern Germany, wind curtailment already occurs. On the one hand this situation is caused by limited network capacities in the event of high wind velocities. On the other hand due to the need for control power of conventional generation to provide system services, wind curtailment is enforced. Meanwhile conventional generation within the TSO region still takes place. This situation which until now is limited to some regions may occur in entire Germany if regulatory strategies are not implemented.

6.2 Support mechanisms and market integration

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. The EEG guarantees fixed tariffs to RES operators for feeding electricity into the grid for a period of 20 years. The tariff depends on the year when the equipment was installed. The feed-in tariff (FIT) is a flat price differentiated by technology.

The TSO sells the RES generation on the day-ahead-market. It is also responsible for wind power forecasts and compensation of deviations in generation. The RES generation enters the market without any minimum price and obtains the merit-order-price. The difference between FIT on the one hand and obtained market price and avoided system charges by decentralised generation on the other hand is paid by electricity consumers (socializing mechanism). The market entry without minimum price will be legally active from 2011 on. In the meantime there is a transitional regulation in place.

Now RES producers do have the free alternative to choose monthly between 1) producing for the market and thus receiving the market price via direct commercialisation or 2) remaining under the fixed FIT. But until now the market selling seems to be the less attractive option to them.

For wind power using FIT the producers get a higher incentive for the first years (at least 5 years depending on the wind location) and a basic incentive afterwards. In this case the basic incentives of approximately 5 ct/kWh are almost comparable to the prices on the wholesale markets. Therefore the direct commercialisation of high shares of wind energy can be expected for the next years.

When using direct commercialisation one important consideration for the wind energy producing owners would be employing a wind power forecast system by themselves (day ahead and shortest term) and the other will be the formation of commercialisation cluster. This is meant to make use of the equalization of forecast errors between widely distributed wind parks. Electric power from wind may be disposed by the owners at the day-ahead-market. Forecast errors can be compensated by the owners on the intraday-market by using shortest term forecast systems. The balance energy must be paid by them accordingly.

The introduction of two additional EEG-bonuses are considered which may improve system integration of RES within EEG. They would be paid by the TSOs/DSOs via the already known EEG socializing mechanism:

- Still under discussion is the “steadiness bonus” or “integration bonus”. It attempts to optimize network capacity utilisation (lesser peak feed-ins, lesser grid congestions) with generation management of controllable RES like biogas, shifting intermittent RES (wind, PV) by stationary batteries and demand side management. All parties will be controlled by virtual power plants. This bonus thus facilitates an integration which is controlled by the demand and the fixed RES generation of PV and wind power. The control signal would differ between the grid requirements of at least 5 regions. But the voltage level and smaller regional disaggregation are not quite clear. The control signal may temporary change in the case of limited grid capacity from a single generic German signal to a location specific signal.
- Introduction of a feed-in premium as an alternative to the FIT, which enables the market integration of RES.

Furthermore, owners of PV panels have the possibility to get an incentive for their own consumption of electricity. This incentive may set stimulation for demand side management and storage technologies at the household level. On the other hand this systems will lead to uneven distributed costs for system charges between consumers with and without own consumption.

Important to note is that there is no double gaining at the moment: RES are momentarily not allowed to participate in the balancing market, if they are receiving FIT.

In Germany, CHP fired with natural gas are supported by an incentive formulated in the combined heat and power plant act (KWKG).

As well as for RES, the combined heat and power plant act guaranties priority access. CHP owners can choose between a fixed price (quarterly updated by the wholesale market price) or sell electricity themselves. CHP owners also receive bonuses for heat production and avoided system charges. Contrary to RES, the CHP gets bonuses additionally - independent of commercialisation. Therefore market stimulation can influence directly the mode of operation. But in practice CHP mainly works in a heat-lead mode of operation. The power-led industrial CHP are generating electricity independent of market signals as well. Furthermore and contrary to RES, the CHP are able to provide balancing energy in addition to the normal generation.

In comparison with Denmark the buffer storages of existing CHP units are still too small for a decoupling of heat and electricity generation. In Germany, also micro-CHP is being subsidized. This creates a viable option for decentralized household generation.

6.3 Connection of DG/RES and network charges

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 *(Infrastrukturplanungs-beschleunigungsgesetz),* 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 will start before the end of 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 is not 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 DG/RES 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.

6.4 Network impact

The majority of DG/RES is connected to distribution networks (150 kV and lower). Only in case of wind power about 15% is connected to transmission networks (200 kV and higher).

Currently, power is mainly transferred from the transmission level downwards in the chain to the end consumer ('top-down'). However, increasing penetration of renewable sources imply that power from intermittent generation will increasingly exceed local load and needs to be exported to other regions. As a result, upward flows may occur as well and power flows alternate between top-down and bottom-up, in other words are bidirectional. Since most non/less controllable production from wind, PV and CHP is directly connected to distribution networks, these networks face the most severe consequences.

The transmission network will face more variable upward flows from the distribution networks as well as more exchange of energy through the interconnections. Besides, changes in locations of load and generation will change the electricity flows in the networks. The main load centres are in the South and West of Germany. Conventional generators are more or less equally divided over Germany. In the North and South are more nuclear and in the West and East more coal plants. The first nuclear plants to close (if there is no political change) are in the South. The largest amount of new generation is planned in the North; offshore wind in the North and Baltic sea as well as new hard coal plants. Besides, the most onshore wind power capacity is installed in the Northern part. Therefore, there will be an even higher need for power transmission from the North to the South in the future, requiring more reinforcements of North-South transmission connections. At the moment the implementation of some of the planned network extensions is delayed.

Until now only avoided system charges are present and officially calculated. But considering the further development of DG/RES rising systems charges have to be expected.

Due to the regional specific high amount of wind generation, sometimes wind turbines are the single suppliers in a region. Therefore wind turbines are enabled to provide systems services like voltage control and reactive power, frequency control and black start capability. All DG/RES connected to medium and high voltage levels have to fulfil these rules. For DG/RES connected to low voltage levels, the regulatory rules are under development. These connection rules partly enable a secure grid management by DG/RES.

6.5 Demand response and smart metering

Smart metering can be implemented to bill consumers according to their actual use instead of their assumed consumption profile. For small customers no large-scale roll-out of smart metering is envisaged as the metering market is liberalised. Customers are free to choose a smart meter. For newly built houses the use of smart meters is obligatory. Electricity prices for small consumer do not differentiate in time. Time-differentiated prices for all customers will be introduced in January 2011 §40 EnWG (German legislation / EnergieWirtschaftsGesetz). Recommended is the introduction of minimum functional requirements for smart meters. This is left to market forces (No legislation actions taken yet). The same applies for the development of common communication standards where several task forces (associations, manufacturers ect.) were founded.

The suppliers offer a special night tariff for night-storage heater and heat pumps. Interruptible contracts like in the case of heat pumps allow suppliers to interrupt power supply for several hours a day.

Presently some pilot projects are in process. They are part of the E-Energy funding programme - ICT-based energy system of the future - of the Federal Ministry of Economics and Technology (BMWi) in an inter-ministerial partnership with the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU). To demonstrate the functioning of smart home area networks for automatic load control, the project “E-DeMa” is carried out which is part of the E-Energy program. In “Smart Watts” (also part of E-Energy) the demonstration of automatic load control is planned.

6.6 DSO regulation (Grid connection and grid expansion)

In Germany the specific regulations for RES are included in the EEG. The EEG obliges grid operators to purchase electricity from renewable energies at a fixed tariff and RES are entitled to grid connection and grid usage, and if necessary, to an expansion of the grid capacity by the grid operator. The respective nearest grid operator is as rule obliged to boost and expand his grid in order to guarantee the purchase, transmission and distribution of electricity from renewable sources. There is one limitation; the grid operator can refuse the grid expansion when the grid expansion is economically and technically not reasonable.
The costs of optimising and expanding the grid are at first costs for the grid operator. The cost of grid expansion may be passed on, through the grid usage fees, to the consumers by adjusting the electricity price accordingly.

6.7 Conclusions

When distributed electricity supply surpasses a particular level, it can no longer be ignored in planning and operation of the electricity networks. With progressive use of renewable energy sources in decentralized generators that are integrated in the distribution network, a bidirectional flow of energy between transmission network, distribution network and customer assets is developing. The influence of this bidirectional flow in the grid will become more and more relevant requiring an active management of decentralized assets. The realisation of the advantages of distributed generation, like reduced system losses, improvement in voltage profile, better power quality and release of power on the existing transmission and distribution network implies the active integration of DG units in the distribution grid. Besides the integration of DG units, the integration of the typical customer in the distribution grid will become more and more important as well. New concepts and strategies are required for operation of a decentralized energy system with operation of customers and price signals for influencing DG units and loads. The extending of the existing technical and legal interface between system operator and customers needs improvements of the regulatory framework of the electricity networks, to overcome the existing legal barriers or lack of standardisation.

Furthermore the establishment of active network management seems to be very important for avoiding RES curtailment. Like already mentioned, wind power curtailment takes already place because of necessary system services for balancing power in general and voltage control and short-circuit current at the transmission network level. So one challenge is to change prequalification criteria and judicial limitation to enable RES to provide balancing power. Dynamic voltage control at the DSO level can diminish the necessary conventional capacity at the TSO level. The recent regulatory connection rules for DG/RES may improve this situation. But until now dynamic control of DG/RES does not take place. It seems be necessary to formulate more specific requirements for a further DG/RES integration.
One fundamental challenge is to find the economical optimum between the necessary network extension and specific DG/RES integrations measurements at DSO level.

7 REGULATORY STRATEGY FOR THE NETHERLANDS

After a certain level of DG/RES penetration, integrating increasing amounts of DG/RES tends to raise distribution network costs and total system costs more than proportionally. This may ultimately hinder the further growth of renewable generation because of the negative impact on the financial position of DSOs. In order to counteract the distribution cost impacts, cost-efficient measures are required to mitigate the adverse cost impacts of distribution networks costs for society as a whole and for DSOs in particular. Therefore, in this chapter a number of regulatory options have been identified that probably lead to lower system cost than would be the case under continuation of current policy and a less adverse incidence of system cost on DSOs.

These are:

- abolishment of priority transport for renewable and energy-efficient technologies (Section 7.1),
- introduction of more cost-reflective network charges for generators (Section 7.2),
- active network management (Section 7.3), and
- allowance for the interaction between support schemes and network tariffs (Section 7.4).

7.1 Integration of DG/RES in power markets

Combined heat and power

Several aggregators are active in the business of aggregating supply from CHP units in industry and agriculture. In horticulture, greenhouses often have a CHP installation with heat storage and a back-up heating system. The resulting flexibility is often used to maximise electricity sales revenues at times of the highest day-ahead market prices. To enhance profits further, some also participate (passively) in the balancing market. In this way, already about two-thirds of the 3000 MW of horticultural CHP units in the Netherlands are integrated into power markets. The remaining one-third consists mainly of smaller CHP units (<1 MW), often situated in older and smaller greenhouses. Their operators appear to be reluctant to spend the time and effort on actively maximizing the benefits from their heating installations.

There do not appear to be any major market barriers in integrating CHP units into power markets via aggregators. In industry, process requirements and lack of heat storage possibilities would seem to be the main technical factors limiting further integration of industrial CHP units into power markets.

Wind

The output of wind farms is generally sold to balancing responsible parties in long-term contracts for a fixed price (often related to the forward market, and including a discount for balancing costs). These balancing responsible parties usually have a large share of flexible power plants in their portfolio. Currently, they do not appear to have any problems in adjusting their fossil fuel power plants to the variable wind output. In 2020 the installed wind capacity in the Netherlands is expected to reach 10,000 MW, which is in the same order of magnitude as the total electricity demand during the night hours. This will likely lead to larger fluctuations in power prices, resulting in more opportunities to integrate flexible DG/RES, especially demand response, into the power markets.

Priority access for renewable and energy efficient technologies
As a result of the chosen implementation of Article 16 of Directive 2009/28/EC in national legislation, the Ministry of Economic Affairs intends to introduce priority transport for electricity from renewable sources in case of congestion. In the Westland region of the province of South Holland, regular congestion occurs due to rapid expansion of the number of CHP units. A temporary congestion management procedure has been introduced, obliging all new CHP in the congestion zone to participate. As part of a proposal for this new congestion management system, all renewable sources and efficient co-generation are excluded from taking part in this system and will therefore get priority transport. One of the variants under discussion forbids DG/RES[15] under all circumstances to reduce output as contribution to congestion management.
However, a special provision for priority transport for renewables is not necessary from both a legislative and system operational point of view. From a legislative point of view, either priority or guaranteed access for renewable generators is required. Since, network operators do have a duty to connect generators and consumers who want a connection, those parties already dispose of guaranteed access and the implementation of Article 16 of Directive 2009/28/EC does not require any additional changes in national legislation.

From a system operational point of view, wind turbines will not be curtailed at all or only in a very limited number of hours per year. First of all, wind turbines have very low marginal costs due to the absence of fuel costs, and will therefore come first in the merit order of power plants. The merit order and marginal costs are important in a market-based congestion management system; such a system provides an incentive to those producers with the highest marginal costs (i.e. with the highest avoided costs of non-producing) to curtail and thereafter to producers with lower marginal costs. Therefore, wind will usually only receive an incentive to curtail in extreme situations, which will rarely happen. The low incentive for wind turbines to curtail is even further diminished by the feed-in premiums for the production of energy from renewable sources. Note that these premiums are granted irrespective of market- and network conditions.

Only under extreme conditions, when grey producers would be willing to pay more than the foregone sales and subsidy benefits of the renewable producers (i.e. with very high congestion charges, or the equivalent of negative electricity prices, below about -50 €/MWh[16]) renewables would have to reduce output. Grey producers do have to make considerable costs for producing during time periods with negative market prices due to the fuel costs during start up and shutdown, and due to increased wear and tear of power plants as well as reduced efficiency and higher CO_2 emissions due to operation in part load. Therefore, the main effect of introducing priority access for renewables will be that investors in grey electricity plants will be faced with additional costs and additional risks.

Under certain system and market conditions, curtailing renewables will result in lower system and net social costs. These lower net costs relate to the incremental benefits of this option, resulting from this option, of improved operational circumstances for conventional generation (less wear and tear of production assets, less part loading with associated higher CO_2 emissions), outweighing the costs of cur-

[15] Actually, the term DER, Distributed Energy Resources, would be more appropriate here, since DG/RES is not supposed to include demand response. In the Improgres project we use the term DG/RES, sometimes also including demand response.
[16] The actual level depends on the details of the relevant feed-in premium. When the annual production is below 1760 MWh per MW installed, then curtailment would become financially attractive for wind farm operators if electricity market prices are below -66 €/MWh. For annual production higher than 1760 MWh per MW, the limit would be a market price of -30 €/MWh (Source: ECN estimates).

tailing renewable generators including the possibly[17] less avoided CO_2 emissions. Consequently, we advise to allow paid curtailment of renewable generators and to seriously reconsider the envisaged priority transport regime.

7.2 DSO regulation: connection and use-of-system charges

Costs of DSOs are affected by increasing shares of DG/RES

With shallow connection charges, and in absence of generation use of system charges, DG/RES generators have limited incentives to contribute to optimising network cost. As a consequence, DSOs are affected when DG/RES implementation increases. In the perspective of an expected fast further growth of DG/RES, this means a serious problem that has to be solved. In any case it seems obvious that there is a need for an adequate compensation method to cope with the resulting disadvantages for DSOs. The first step should be to develop a method for allocating costs to both loads and producers.

In this project, for the calculation of the grid costs caused by producers, a marginal approach has been opted for. The marginal costs are calculated as the difference between the cost of the grid without producers and the costs of the grid with producers. The presented shape of costs caused by producers is based on this way of calculation. From a historical perspective with distribution grids without any production it is a plausible way to start the calculations of grid costs of producers.

Yet in the light of expected future developments with fast increase of DG/RES, one can question the appropriateness of the marginal approach. In more and more situations, the capacity of local or regional production will exceed the capacity of local demand, resulting in shortages of capacity when 'maximum production minimum load' snapshots are to occur. In those situations the marginal costs of expansions of the grid seem to be caused only by producers. Turned upside down, under those conditions the marginal costs of an increase of load seem zero. Our case study area 'Kop van Noord-Holland' and the area 'Westland' have already evolved into typical examples of such situations that are expected to become more widespread in the future.

Therefore a very important conclusion is that - in near future in which distribution grids increasingly are dominated by the requirements of distributed generators - a marginal approach is no longer an adequate way for the allocation of costs between load and production. Costs can no longer be unambiguously attributed to load and production. A first overall conclusion of this analysis could be that in a future with high penetration rates of both load as well as production, it seems logical to choose for a more integral allocation approach for the attribution of the integral costs of grids by giving equal weights to connected load as to connected production. *A further detailed research on the allocation of costs is recommended*. In such research further attention is needed to obtaining figures on simultaneous load and production; on the local, regional and even national level. Such properly obtained figures enable identification of differences in cost performance for distinct types of distributed generation, which can be put to good use in cost allocation.

[17] Priority access for DG/RES may raise part loading of conventional generating assets providing system balancing services. This may raise GHG and other pollutant emissions offsetting to a certain extent emissions reductions of renewable electricity substituting for fossil-fuels-based electricity. Hence, more DG/RES is likely to lower the overall specific GHG emission values but less so than might be anticipated in first instance.

Connection charges
Currently, connection charges are levied upon both generators and consumers. Connection charges for generators and consumers with a connection below 10 MVA are shallow, regulated and averaged. Charges include:

(i) a one-time connection charge (dependent on connection capacity, consisting of four components, differentiated for units within and beyond 25 meter from the grid). The distance component beyond 25 meter provides a small locational incentive to install the generator at short distance from the grid;

(ii) a periodic connection payment (dependent on voltage level and consisting of two components; one fixed amount related to a connection with a maximum length of 25 meters; one marginal variable amount related to every additional meter more than 25 meters).

Connection charges beyond 10 MVA are also shallow, but based on actual connection cost to the technical most suitable connection point. This is not necessary the shortest distance to the nearest cable. Therefore these charges can differ to somewhat more than for small production units (below 10 MVA) because of the individual location of production from the existing suitable grid.

Use of system charges
Currently, the incidence of Use of System (UoS) charges is almost exclusively upon consumers. To that effect, a very small transport-volume-independent charge constitutes the exception. 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. Moreover, from the point of view of the system operators, the implementation of shallow connection charges is not the favoured option, *if* the costs of network reinforcement due to new DG capacity on their respective networks are not fully recovered. Therefore, the introduction of cost-reflective use of system charges for generators is recommended. Coordinated implementation of this measure, at least in the North-West European market but preferably at a wider European level, is highly recommended[18]. The latter is of relevance, since an uneven implementation of UoS charges for generators might result in a non-level playing field across the EU.

UoS charges can be either fully capacity-based (kW) or energy-based (kWh) or a mix of both. To the extent that UoS charges are capacity-based, this is to account for the fact that the required network capacity for network users is mainly capacity-based. This relates to the fact that DSOs have to guarantee the connection and transport of the energy produced by DG on their respective networks at full capacity, taking into account existing complementarities between production patterns as well as the interaction between production and consumption patterns. To the extent that UoS charges are energy-based (kWh), this is to account for the fact that network costs are not only related to investments in additional network capacity, but also to O&M costs like energy losses which are related to the actual amount of energy transported through the network. However with fully energy-based UoS charges, energy sources with low load factors do have to pay for only a part of the network costs they induce to the system. This situation would imply a de facto cross-subsidisation with regard to network costs of energy sources with low load factors by those with high load factors. At least from a cost-causality point of view this is clearly sub-optimal. Consequently, our finding is that *UoS charges should preferably be dependent on both kW production capacity and kWh energy produced. Further research is needed to establish the optimal mix in kW and kWh charges.*

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[18] These two closely interrelated recommendations in italics are in line with recommendations provided in earlier projects like Sustelnet, DG-GRID, SOLID-DER and RESPOND.

Furthermore, since the network impacts of RES-E/DG differ with respect to time and location, in theory efficient integration of renewable sources can be improved by temporal and locational[19] differentiation of UoS charges. As mentioned above, to date the shallow connection tariffs already include a quite modest form of locational signal. Signals that provide information on which hours of the day to shift generation or loads to/from can lead to "peak shaving" of required use of network capacity. Hence, it can be beneficial in postponing network investments. This way, generators receive an incentive to behave in accordance with system needs when deploying their units. Many generators already have the possibility to react to variable network charging if and when this would be introduced, since they already dispose of smart metering. This stems from the requirement in the prevailing secondary legislation (metering code) that remote metering is to be applied for every 15 minutes to network connections of 0.1 MW and larger. Before introduction of differentiated UoS charges, a further research on possible effects on grid costs is recommended. One of the issues to be analysed is the question whether it is possible for DSOs to distinguish in tariff-incentives between different DG in different sections of the network if in one section ANM would be useful while it is not needed in another section.

As long as the introduction of use of system charges is not implemented, an adequate method of compensating DSOs is inevitable and recommended. Otherwise DSOs with a high penetration degree of DG/RES are faced with major financial disadvantage with a risk of an understandable unwillingness to an active cooperation in supporting growth of RES.

7.3 Active Network Management

Active network management implies reliance by the DSO concerned on active participation within his network area of distributed network generators, loads, and if applicable power storage devices for the provision of network services. In principle, active network management can be introduced after adoption of more cost-reflective distribution network tariffs in accordance with principles explained in the preceding section. However, in chapter 4 it was concluded that the business case for reducing network cost by intelligent operation of DG/RES units is relatively weak. Gaming issues make dependence of the DSO on a small number of operators undesirable. Large numbers or small units such as heat pumps or charging electric vehicles are less prone to gaming, but the ICT costs is expected to be larger.

Flexibilisation of distributed generation and loads is of key importance to enabling the integration of an increasingly larger share of wind energy in NW-Europe. Smart integration of DG/RES should be pursued primarily for the sake of integration of intermittent sources such wind and solar energy. To a lesser extent, because of the expected limited scope, it should be pursued for reasons of reducing network costs.

7.4 Support mechanisms and certificate markets

The 'Stimuleringsregeling Duurzame Energie' (SDE) is the Dutch government's main subsidy instrument in support of the application of renewable energy in The Netherlands. The production of both renewable electricity and green gas is supported under the SDE scheme. It is a so-called feed-in premium (FIP) system. The premiums are technology-specific for renewable energy technologies, qualifying for SDE support in accordance with SDE regulations set by the Dutch government. For each quali-

[19] That is, different network tariffs within a DSO region, depending on the location.

fying technology, the premium is set at a level that fully covers the financial gap for RES-E producers each year, the production costs are determined for the different renewable energy technologies, supported in the SDE scheme.[20] During the subsidy period of 15 years[21] the production costs are fixed; the premium is adjusted annually ex post solely on account of changes in average market prices in the relevant electricity and gas markets. In SDE terminology the above is summarized as follows: based on the projected production costs a *base tariff* is established ex ante. The base tariff takes into account the additional costs for the generator of electricity production and sales. The payable *subsidy tariff* is equal to the *base tariff* minus the *correction tariff*. The correction tariffs is based on the average market price, including compensation for the cost for imbalance settlement. The subsidy tariff is set each concession year at an ex post adjusted level so as to stabilise the average income of the energy producer per unit of energy in successive years.

Yet a ceiling for the subsidy tariff is defined: the *base electricity or gas price*, which equals two thirds of the projected long term electricity or gas price. If the realised relevant energy prices turn out to have skidded below two thirds of the ex ante projected price level, the subsidy tariff is capped. *Hence, electricity generators benefiting from SDE support run a certain (modest) price risk: at very low electricity prices the SDE subsidy cap might become binding.*

In the Netherlands, “green power” electricity products are quite popular as up to 2004 these products were heavily marketed as due to fiscal facilities this brought high returns to suppliers. Currently “the greenness” of green power products is marketed at a small loss by suppliers aiming at conquering market share from environmentally concerned household customers and customers from the business sector wishing to signal their “green” credentials to their customers. The green power market is sustained by Guarantees of Origin (GoO) that are issued to qualifying renewable electricity generators in the country where they feed their qualifying production into the grid. Because of the high demand for GoO created by its green power market, the Netherlands is a net importer of GoO. As the prevailing regulation is rather lax as far as environmental additionality is concerned, the price of GoO tends to be low. As GoO are traded bilaterally, public price records do not exist. Yet available indications suggest that the revenue stream for qualifying renewable generators for the transfer of GoO issued to them is rather low compared to the sale of renewable electricity, i.e. typically some 0,2-1 €/MWh on a gross basis. From this amount transaction costs to CertiQ, the operator of the GoO tracking system in the Netherlands as well as the cost of dedicated staff time and IT expenditures by renewable electricity generators have to be deducted.

The prevailing SDE subsidy regulation sets the base tariff for the SDE subsidy of a certain generating installation vintage year for a certain SDE technology category. The unit subsidy rate is not time-dependent. In other words, electricity market and network conditions, and consequently network cost impacts, do not have any repercussions for the SDE subsidy rate. It is acknowledged that allowance for network cost impacts can best be allowed for by introduction of (eventually time-dependent) generation use of system (transport) charge. By contrast, Jansen et al. (2007) advised to relate the market support benefits of eligible generation technologies to a benchmark wholesale power price on the

[20] Note that certain generic renewable energy technologies with a wide cost bandwidth are split further into separate qualifying categories with much less diversity in cost performance. This procedure seeks to further reduce windfall profits of SDE beneficiaries.

[21] For thermal conversion of biomass and the digestion options supported under SDE, both for the production of electricity and green gas, the subsidy period is set at 12 years .

relevant power exchange, e.g. the day-ahead price of the APX. Recently, Sjak Lomme suggested a simple to implement a simple rule to withhold SDE subsidies for qualifying production at hours with a spot price lower than 10 MWh/€.

7.5 Demand response and smart metering

The increasing supply from intermittent renewable energy sources adds one additional source of stochasticity to the generation mix, which lowers the flexibility of generation to follow demand. In order to compensate for this decrease of flexibility, demand could be made more responsive to system conditions, for increasing system flexibility. Shifting load from peak to off-peak periods lowers not only demand for generation peak capacity, but also demand for additional network capacity. As marginal costs of reducing demand are generally deemed lower than marginal costs of additional generation and network capacity, it is more efficient to reduce demand instead of deploying additional generation and network capacity to enlarge the flexibility and controllability of system operation.

Required network capacity can be diminished both for the investment and operational time scales i.e. demand response can play a role in reducing the need for network reinforcements as well as reducing network congestion. First of all, demand response lowers the peak demand on which networks are dimensioned under a passive network management approach. Therefore, expensive network reinforcements may be postponed or cancelled lowering the costs of network planning. Secondly, demand response may be part of contracts between DSOs and consumers to prevent network congestion.

For participating in demand response actions, consumers need to dispose of frequent signals of their electricity consumption as well as incentives to take into account the value of demand response which differs substantially in time and is increased by the stochastic nature of intermittent production which increases variability of energy flows.

Concerning electricity consumption signals, only large customers with a network connection capacity of 0.1 MW receive frequent signals as they dispose of a telemetric-meter/remote readable meter while smaller consumers connected to the low voltage network do not dispose of smart interval metering. Therefore, currently small consumers cannot participate in demand response actions.

Different types of incentives can be attached to these signals to induce demand response; price incentives either directly through market prices and network tariffs or indirectly through interruptible contracts. Concerning market price based incentives, large consumers already face hourly wholesale market prices either directly (if they are contracting energy directly on the market) or indirectly through the supplier. However, consumers connected to the low voltage network do not dispose of hourly pricing. Instead, they may choose for simple time-of-use tariffs differentiated to peak hours (working days, generally 7.00-23.00 h) and off-peak hours, although most consumers are wholly shielded from the fluctuations in real-time prices. In order to increase demand flexibility *for low voltage consumers, implementation of smart metering in combination with hourly pricing is advised*. As an alternative to hourly pricing, customers may be enabled to close interruptible contracts through virtual power plants with network operators in exchange for rebates on their energy bill.

In case energy flows in the regional distribution network show the same development as energy flows in the total electricity system, demand response can be based on electricity market price incentives as this will also limit network congestion and postpone network investments. However, it is likely that the direction and size of energy flows in regional networks will regularly differ from the direction and size of energy flows in the system as a whole. For this reason, time-differentiated market prices cannot steer network flows in regional networks sufficiently and should be complemented by variable network tariffs. The latter provide signals to consumers to take into account the network situation in their consumption pattern and in that way may limit congestion and postpone additional network investments. Currently, consumers do not face time-differentiated network charges. This issue is further explained in the next section.

Apart from that, the implementation of smart metering and pricing probably will be not enough to drive consumers' behaviour since consumers probably still face a lack of incentives to react on variable electricity prices as the demand response potential is limited. Small consumers cannot be expected to follow market prices and their consumption continuously due to prohibitive high transaction costs. *Introduction of automated smart home area networks (HAN) which automatically shift demand to low price periods is recommended to overcome this barrier.*

7.6 Network planning

Distribution companies are usually only willing to invest in grid extension with firm commitments from the side of their clients. On the other hand, clients are reluctant to commit themselves before financial closure of their investment plans. But this does not appear to provide problems in practice. DSOs have a legal obligation to connect new customers within 18 weeks, and seam to stick to this. However, the regulator overseeing DSOs should closely monitor the speed with which DSOs respond to requests for connection and incentivise DSOs by carrots and sticks.[22]

7.7 Conclusions and recommendations

Connection charges

For providing fair and non-discriminatory network access to the network for different kinds of generators including small renewable generation units, it is important that connection charges remain shallow.

Generator Use of System charges

The introduction of cost-reflective use of system charges for generators is recommended. Coordinated implementation of this measure, at least in the North-West European market but preferably at a wider European level, is highly recommended.[23] The latter is of relevance, since an uneven implementation of UoS charges for generators might result in a non-level playing field across the EU.

As long as the introduction of use of system charges is not yet implemented, an alternative, adequate method of compensating DSOs is recommended.

[22] See Chapter 3 for more details.

[23] These two closely interrelated recommendations in italics are in line with recommendations provided in earlier projects like Sustelnet, DG-GRID, SOLID-DER and RESPOND.

Cost-allocation

In near future in which distribution grids increasingly are dominated by the requirements of distribution generators only an integral approach for the allocation of costs between load and production is justifiable. A further detailed research on the allocation of costs is recommended.

In analysing the need for grid capacity and related costs two snapshots are relevant in all levels of the grid: 'maximum load and minimum production' and 'minimum load and maximum production'.

Priority rights for DG/RES to network transport services

It is advised to reconsider in earnest current plans to grant priority transport rights to DG/RES generators. Adoption of these plans would mean a large step back into the road towards supply-side responsiveness to the cost impacts of - and consequently the cost-effectiveness - of DG/RES network integration as well as the introduction of active network management and other smart grid concepts.

Make SDE subsidy rates contingent on prevailing market conditions

Relate the market support benefits of eligible generation technologies to a benchmark wholesale power price on the relevant power exchange, e.g. the day-ahead price of the APX. For instance, a simple regulation may be introduced to withhold SDE subsidies for qualifying production at hours with a spot price lower than 10 MWh/€, adjusting ex ante the SDE subsidy base tariff upwards accordingly. Also adoption of this recommendation would help to reduce the total social unit cost of DG/RES-based electricity on a delivered basis.

8 REGULATORY STRATEGY FOR SPAIN

This section will provide a regulatory strategy specific for the Spanish case to facilitate the integration of large shares of DG/RES and to ease the development of the smart distribution grids. Firstly, the Spanish electricity system is briefly described. Thereafter, specific issues concerning DG/RES integration will be dealt with separately.

8.1 Present DG/RES situation and its expected evolution

The Spanish electricity system is characterised by an already significant share of electricity produced from RES and, to a lesser extent, CHP units. An estimate of the installed capacity of the "Special Regime" technologies[24] is provided in Table 8.1. According to the Spanish TSO, wind power accounts for 19% of total capacity which produced 13% of total electricity demand in the year 2009. The remaining "Special Regime" capacity constitutes 15% of total capacity and generated 14% of the 2009 electricity consumption in Spain. The amount of CHP, mostly natural gas fired, and solar PV capacity are particularly relevant. Nonetheless, high-temperature solar thermal electricity generation is steadily gaining in importance.

Table 8.1: Installed "Special Regime" capacity end of December 2009. Source: Spanish Energy Regulatory Commission (CNE)

Technology	Installed Capacity [MW]
Wind	18096
Solar PV	3469
Thermal Solar	136
Small hydro (≤10MW)	1391
Medium hydro (>10MW, ≤50MW)	629
CHP	6271
Biomass	495
Biogas	171
Urban Solid Waste	279

In Spain, transmission networks are those with rated voltages of 220kV and 400kV, whereas distribution networks comprise HV, MV and LV networks ranging from 132kV to 0.4kV. The voltage level at connection point widely differs per generation technology. Hence, those units connected at 132kV or less could be considered as DG, according to the definition provided in EU Directive 2009/72/EC. Figure 8.1 shows the share of the former Special Regime capacity that is connected at each voltage level. It can be observed that most CHP and PV capacity is connected at distribution level. However, this does not hold true for thermal solar and wind. Most capacity of the remaining technologies is connected at distribution voltage levels too. According to our own estimates based on the data provided by CNE and REE, at the end of 2009 there were around 20.5 GW of DG capacity in the Spanish system. This accounted for approximately 21% of total installed capacity.

[24] The "Special Regime", as opposed to "Ordinary Regime", comprises those technologies that receive support payments to enhance their development due to their environmental benefits, i.e. RES (except for large hydro plants), wastes and CHP.

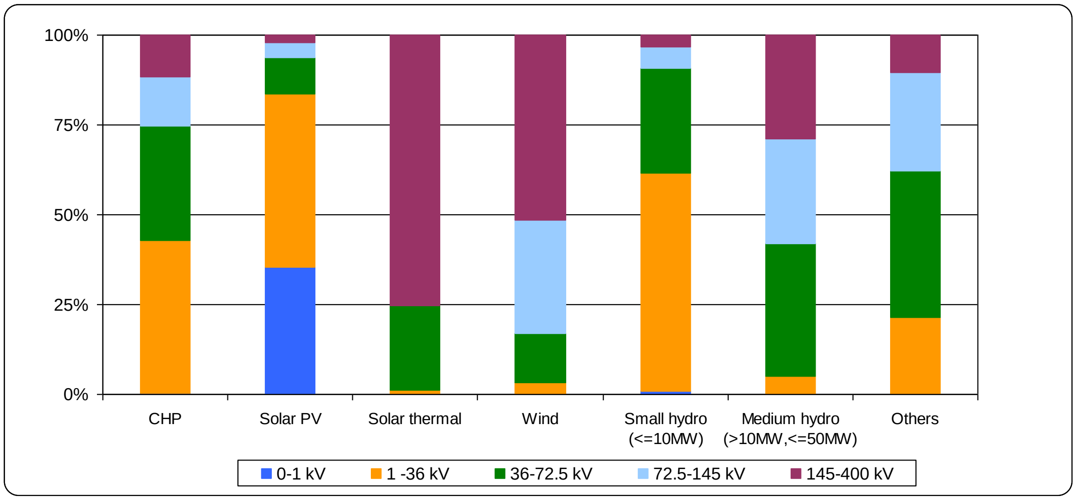

Figure 8.1: Share of Special Regime capacity per voltage level, Spain, 31st December 2009. Source: CNE. Figure: own elaboration

A significant increase in intermittent DG/RES penetration in the Spanish electricity market is expected from onshore wind, solar (both PV and thermal) and, to a lesser extent, CHP. This growth will be accompanied by a moderate annual load growth of around 2% for the coming years (Eurelectric 2005). On the other hand, current interconnection capacity with Portugal and France is relatively limited compared to total available generation capacity at national level. Significant investments in the transmission grid are being studied both to accommodate larger shares of wind power and increase the interconnection capacity with neighbouring countries.

The following subsections will focus on the integration of DG/RES in markets, the support payments they receive and how to integrate DG in distribution networks towards the realization of smart grids.

8.2 Integration of RES/DG in power markets

The “special regime” generators have the choice to inject all their production directly into the network and receive a feed-in tariff (FIT) per kWh or sell their production freely at the market and receive a feed-in premium (FIP). These possibilities will be further discussed when dealing with the support mechanisms. Initially, DG/RES generators tended to opt for the FIT. However, a larger share of the newer units is deciding to sell their production directly at the market. The share of the DG/RES capacity and installations that trades at the market is shown in Figure 8.2 it can be seen that most wind capacity is traded at the market, around 94%. Solar thermal and medium hydro (between 10MW and 50MW) units mostly sell at the market too. On the other hand, around half the installed capacity of CHP and other thermal technologies (the label others comprises biomass, biogas and waste treatment) are still under the FIT option. Finally, all solar PV units are still under this FIT option.

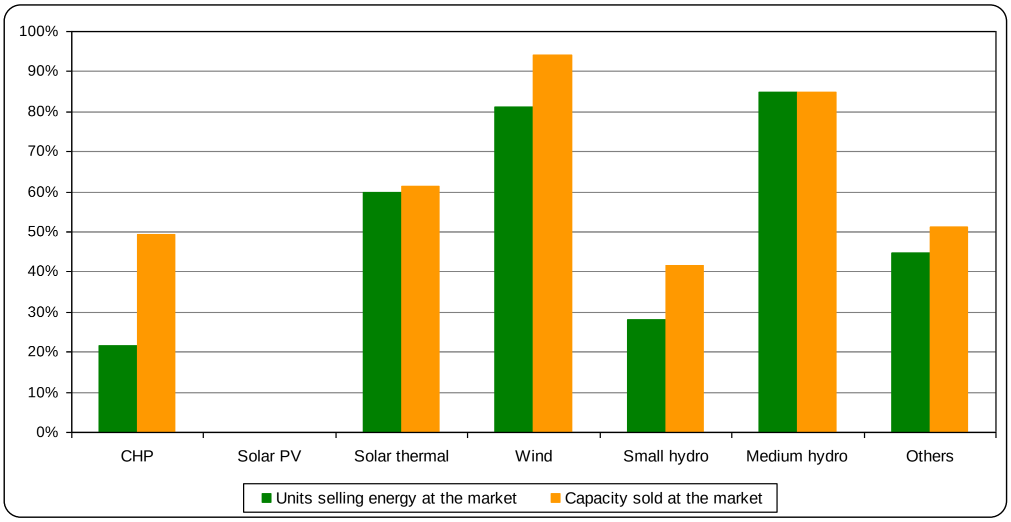

Figure 8.2: Capacity and number of installations that sell energy at the Spanish electricity market, October 2009. Source: CNE. Figure: own elaboration

One of the main reasons that prevent CHP units from participating in power markets is that they are mainly industries whose main activity is different from the electricity production. Thus, selling energy at the wholesale market may represent an added complication which they are not willing to undergo. On the other hand, high-temperature solar thermal constitutes a promising technology that is drawing increasing attention in Spain. In spite of being a quite new technology, a significant part of these installations are already trading at the market. However, its future evolution is still rather uncertain.

Size limitations are often cited as one of the main barriers for DG/RES to access the markets. However, Spanish regulation does not contain any unit size limitations to enter the wholesale electricity market. Notwithstanding, aggregation would allow them to reduce the transaction costs and mitigate the risks of imbalances. Note that DG/RES operators are made fully responsible for their electricity generation deviations as they pay imbalance penalties proportional to their contribution to overall system imbalance. In order to improve the balancing market efficiency and increase the role of smaller generation entities and demand, the creation of aggregators should be encouraged. Aggregators would then become an agent in charge of keeping the balance between generation and demand by scheduling their generators output and demand entities consumption either internally, or by participating in the intraday market or other balancing markets. Aggregators, albeit allowed by current legislation, are not broadly developed yet.

Increasing penetration of intermittent generation is usually expected to increase the need for regulating power. However, the amount of balancing power required in Spain has not varied much. For example, Figure 8.3 shows that the secondary reserve needed has not increased significantly despite the fact that wind capacity has indeed increased. This integration has been facilitated by the renewable control centre (CECRE) implemented by the Spanish system operator REE. The maximum wind energy output that the system can allow under safety conditions is calculated in real time. If the actual production surpasses this value, any wind unit connected to CECRE can be curtailed in real-time. The functioning of this control centre has been described in more detail in (Zvingiliate et al. 2008).

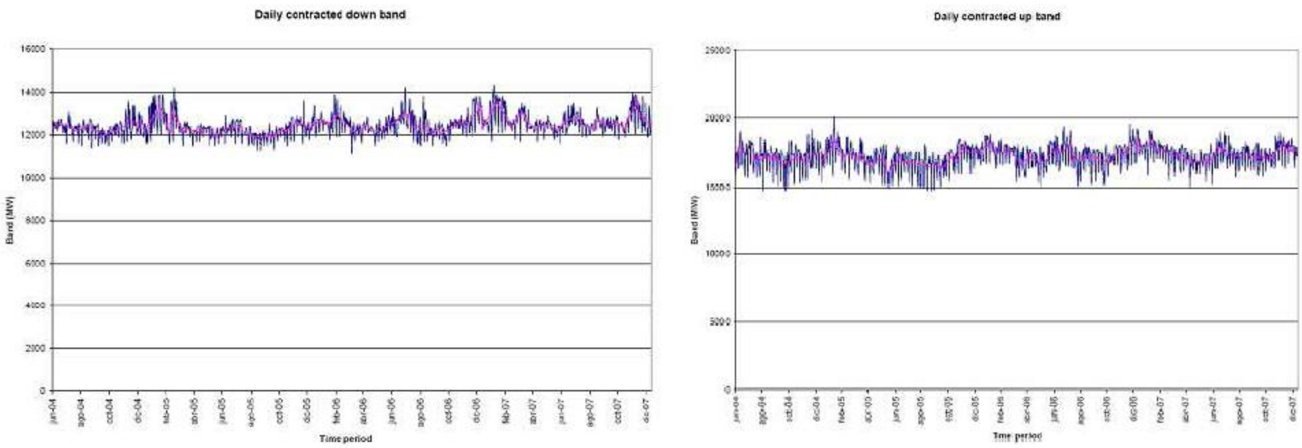

Figure 8.3: Daily contracted secondary reserve up and down in Spain between june 2004 and december 2007

In order to reduce their imbalance, electricity generators can trade at the intraday market. Gate closure time of the Spanish intraday market is between 2 and 6 hours. The needs for regulation reserves and energy (or the risk perceived by DG/RES operators) could be reduced by moving the gate closure time closer to real-time to diminish prediction errors.

Concerning DG/RES, only controllable units that sell their energy in the wholesale energy market are allowed to participate in the balancing markets. The conditions a generator needs to fulfil for being considered controllable are set by the system operator. Additionally, these units must be communicated with a generation control centre that directly communicates with the TSO control centre CECRE. The costs of these generation control centres are incurred by the DG/RES operators. Nowadays, DG/RES units are currently not participating in the balancing markets in Spain due to the difficulties in complying with technical requirements and a support scheme design that does not encourage DG/RES to do so. Controllable units should be encouraged to participate in balancing markets in order for the system to cope with high DG/RES penetration levels. Furthermore, currently non-controllable generators should be incorporated as well if the future technical developments allow this to happen.

8.3 Support mechanisms and certificate markets

According to Royal Decree 661/2007 on electricity production by “special regime” units, the main support mechanisms for DG/RES in Spain are price-based; no certificate market exists. The “special regime” generators have two options to sell their production; they can either receive a FIT or a FIP over the market price. In the latter case, a cap and floor mechanism has been introduced for some technologies, i.e. if the market energy price plus the premium is higher or lower than some fixed values, the energy produced will be remunerated at those cap and floor values instead of the market price plus the premium. As a result, the generator is protected against low market prices whereas excessive payment is prevented when high market prices occur. DG/RES producers, even those receiving a FIT, are obliged to communicate their expected production to the TSO and are penalised if deviations surpass a certain threshold. The expected production from these units is included in the market dispatch through a representative entity.

The FIT and premiums are held all along the lifetime of the installations, although they do not remain unchanged through time. In most cases, they both have two differentiated tariff periods (e.g. 0-15 years, 15 years onwards) that vary from one technology to another. An exception is made in the case of wind power and biomass or biogas powered plants, where the premium over market price is removed after 20 and 15 years, respectively. The values for the FITs and FIPs are updated periodically depending on the primary energy source and the evolution of the retail price index RPI and fuel price indices. The FIT and premiums paid to the “special regime” generators in Spain are summarised in Table 8.2.

CHP, small and medium hydro and plants powered by means of biomass, biofuels or residues may opt to a time-of-use (ToU) differentiated FIT (no differentiation is made in the FIPs). Being this the case, they would be paid a slightly higher FIT during peak periods, and lower than usual FIT while at off-peak hours. No differentiation is made by voltage level at connection point, albeit this factor can be implicitly taken into account when segmenting by the size of the plant and kind of technology.

Table 8.2: FITs and premiums paid to the most relevant "special regime" generators in Spain from 1st January 2010

<table>
<tr><th>Technology</th><th>Power Range</th><th>Start year</th><th>End Year</th><th>FIT</th><th>Premium</th><th>Cap</th><th>Floor</th></tr>
<tr><td rowspan="2">Windpower (on-shore)</td><td rowspan="2">No differentiation</td><td>0</td><td>20</td><td>7.75</td><td>3.10</td><td>8.99</td><td>7.54</td></tr>
<tr><td>20</td><td>Onwards</td><td>6.47</td><td>0</td><td colspan="2">N/A</td></tr>
<tr><td rowspan="2">Solar thermal</td><td rowspan="2">No differentiation</td><td>0</td><td>25</td><td>28.50</td><td>26.87</td><td rowspan="2">36.39</td><td rowspan="2">26.88</td></tr>
<tr><td>25</td><td>Onwards</td><td>22.80</td><td>21.50</td></tr>
<tr><td rowspan="6">PV*</td><td rowspan="2">P≤100 kW</td><td>0</td><td>25</td><td>46.59</td><td rowspan="8">N/A</td></tr>
<tr><td>25</td><td>Onwards</td><td>37.27</td></tr>
<tr><td rowspan="2">100 kW<P≤10 MW</td><td>0</td><td>25</td><td>44.17</td></tr>
<tr><td>25</td><td>Onwards</td><td>35.34</td></tr>
<tr><td rowspan="2">10<P≤50 MW</td><td>0</td><td>25</td><td>24.31</td></tr>
<tr><td>25</td><td>Onwards</td><td>19.45</td></tr>
<tr><td rowspan="5">CHP (Natural Gas)</td><td>P≤0,5</td><td colspan="2" rowspan="5">After 10 years, an age correction is applied that depends on the installed capacity</td><td>12.72</td></tr>
<tr><td>0,5<P≤1</td><td>10.44</td></tr>
<tr><td>1<P≤10</td><td>8.14</td><td>3.41</td></tr>
<tr><td>10<P≤25</td><td>7.70</td><td>2.80</td></tr>
<tr><td>25<P≤50</td><td>7.29</td><td>2.49</td></tr>
</table>

*These FITs correspond to installations in operation before RD 1578/2008 entry into force in September 2008

The premium on the top of the market price is seen as a more efficient incentive than the constant feed-in tariff. Generators receive the market price signal as a good indicator of the value of the energy at each hour of the day. However, the constant premium still can distort the efficient behaviour of some generators. For instance regarding controllability for system balancing, a generator will not offer a bid to decrease its output, if that is required by the system operator, because the incentive it receives for every kWh supplied is very high.

Support payments to DG/RES are considered to be one of the main causes of the current tariff deficit in the Spanish electricity system. Consequently, the Ministry of Industry, Tourism and Trade has recently passed regulation which aims at limiting the amount of new RES capacity that is allowed to connect (RD 1578/2008 and RD-Law 6/2009). This regulation establishes a mixed price and quota based mechanism intending to promote a sustainable growth of DG/RES by adapting support payments to technological development. Despite this regulatory approach is deemed appropriate, several problems arose during the transitional periods. This problem should be satisfactorily dealt with if the future development and integration of DG/RES in the Spanish system is to be ensured.

8.4 Demand response and smart metering

The connection of large DG/RES penetration levels can be eased by increasing the responsiveness of the demand side of the electricity system. Nevertheless, demand response in Spain is scarce nowadays.

Large electricity consumers connected to the high voltage networks with a contracted capacity of over 5 MW can sign interruptible contracts. The corresponding compensations depend on the total interruptible load to which consumers commit and are unrelated with time or geographical location. This mechanism could be improved by incorporating some kind of differentiation in the contracts or by assigning them through more market-based mechanisms. Residential LV consumers with electrical heating and storage capability used to be under a night-period tariff. This tariff caused significant troubles in some distribution areas as all heating equipments switched on at exactly the same time and it was necessary to reinforce the network only for this peak. The night-period tariff was replaced by a two-period TOU last-resource tariff and TOU access tariff[25]. However, current schemes are clearly insufficient to achieve a true involvement of LV consumers in demand response programs.

Incorporating small LV consumers into demand response programs can only be achieved by a large-scale deployment of smart meters. Spain has in fact planned for the replacement of traditional electricity meters with smart electricity meters before December 2018. In addition, demand response mechanisms should be fully operational by January 2014 (Lobato et al., 2009). Nonetheless, the installation of smart meters is not enough by itself to attain all the benefits of demand response. Once smart meters are installed, the demand response programs would have to be defined and implemented. The definition should clearly state the role and interactions between the regulator, retailers and DSOs (who nowadays own the meters in Spain) and consumers themselves. The future development of home automation is deemed key in achieving the whole potential benefits of demand response. Nonetheless, this would require an important change of mind in the way energy consumers behave.

Additionally, in a Spanish context, the following actions are deemed advisable: i) provide consumers with electricity prices that reflect its true costs (avoiding protective regulated tariffs when possible), ii) develop a fully liberalised retailing sector[26] and iii) promote the use of home automation when technically and economically possible.

8.5 DSO regulation: connection and use of system charges

At the beginning of 2008, legislation for a new regulatory framework to set DSOs regulated revenues was passed[27]. The new framework consists of a revenue cap with 4-year regulatory periods. The new regulation provides incentives not only to increase economic efficiency but also to improve some quality indicators (energy losses and continuity of supply). The new regulatory framework allegedly includes the increments in costs due to the connection of DG. This is done through the use of a Reference Network Model, similar to the ones used to compute the impact of DG on distribution costs in WP4 and WP5 of the IMPROGRES project (Cossent et al., 2008).

[25] The access tariff comprises all the system costs but the energy costs, i.e. distribution charges, transmission charges, system operation, regulator, support payments for RES, etc.
[26] Since July 2009, the retailing activity is liberalised. However, most small consumers still pay a last resource tariff to one of the last resource retailers which in fact coincide with the biggest DSOs. DSOs formerly were in charge of collecting the regulated tariffs from consumers. Consequently, many consumers are probably not fully aware of the change yet.
[27] Royal Decree 222/2008, 15th of February, on remuneration of electricity distribution activities. Available on-line at http://www.cne.es/

The latest regulatory changes seem to be in line with the adequate integration of DG/RES as the impacts of DG on costs will be considered. Nonetheless, the efficiency of current regulatory arrangements should be assessed and modified accordingly. Moreover, a methodology to compute and include into the regulation the impact of DG/RES and demand response on losses and continuity of supply should be developed.

DSOs recover the allowed revenues through connection charges and UoS charges. These will now be covered. The conclusions drawn in this subsection are based on the results from the DG-GRID and SOLID-DER projects, for more details on this subject see (Gómez et al., 2007) and (Cossent et al., 2008 and 2009).

Connection charges:

At the moment, DG/RES pay deep connection charges. These deep connection charges are computed by DSOs and negotiated with DG/RES operators through opaque rules. In case of non-agreement a case might be taken to the National Energy Commission (CNE) for arbitration. On the other hand, in cases where DSOs are in fact benefiting from new DG/RES connections, for example through investment deferral or reductions in energy losses, these benefits are never shared with DG/RES.

In order to prevent large negotiation processes, creating financial barriers and disputes, it is recommended that DG/RES units pay only transparently regulated shallow connection charges. The remaining connection costs would be socialised via the UoS charges included in the access tariffs. This recommendation is especially relevant for small DG units.

Use of system charges:

Spanish electricity generators are not paying UoS charges, irrespective of the voltage level. It would be advisable to provide stronger incentives to these units so that they will increasingly take into account the impact of their operations on the network. Implementing this feature would require an amendment of the Electricity Law[28]. Due to the low degree of interconnection with neighbouring countries, with the only relevant exception of Portugal, harmonization of UoS charges at EU level is not as important as in other cases such as The Netherlands.

Time differentiation in UoS charges can be achieved through different structures and tariff levels depending on the overall consumption level and the voltage level at the point of connection. However, geographical differentiation is not so straightforward. Currently, Spanish legislation does not allow for geographically differentiation of UoS tariffs for consumers (generators do not pay UoS). As a general rule, a more flexible and efficient electricity system is realised when the actual consequences of differences in electricity generation and demand patterns across regions and over time are passed-through to network users. Therefore, removing the barriers that hamper pricing structures that enable differentiation both in time and in location is recommended.

8.6 Active network management

Presently, active network management strategies have not been adopted by DSOs in Spain. On the one hand, demand response is still to be implemented and, on the other hand, the connection of DG has been done through a “fit and forget” paradigm. Hence, there is still room for improvement in this

[28] This modification would involve a complicated and long process as new Laws or amendments to existing ones need to be passed by the parliament. As a temporary measure, differentiation could be introducing via the support payments. In principle, there is no Law that prohibits this.

subject. Hereafter, a review of system services that are currently being provided by DG/RES and the regulatory initiatives is performed. Moreover, recommendations will be made. The focus will be placed on DG/RES since demand response has been addressed in a separate subsection.

Congestion management in transmission network is done via redispatching generators (no locational economic signal is sent to generators). Redispatched generators, included RES-based producers, are given 15% of the wholesale electricity market price in case of curtailment. The priority rules to curtail the production due to technical constrains are, in this order, (1) “ordinary regime” and (2) “special regime”, of which first non-RES units, and second RES units. Thus, RES power (mainly wind) can be curtailed by the system operator with limited payment when overall system safety rules are at risk, albeit only as last resource. Growing DG/RES penetration levels may originate new congestions at distribution level. However, the only alternative nowadays is to enhance network capacity, even though the congestion may occur for a very limited number of hours per year. Therefore, both explicit congestion management procedures and planning rules to determine when network expansion is required due to non temporary congestion are needed to be implemented at the distribution level.

Currently all generating units belonging to the “special regime” are encouraged to contribute to voltage control through a *bonus/malus* scheme. This is done by keeping the power factor at the connection point within a certain range. The particular bonus or penalty is dependent on the actual power factor and the time of day (peak vs. off-peak hours). However, the scheme does not take into account the location of voltage control violation and therefore the incentive is not deemed optimal by DSOs. On the electricity demand-side, only large consumers with contracted capacity of over 15 MW can provide voltage control at the transmission level. Therefore operational procedures for voltage control by DG and controllable demands are required to be developed and implemented at the distribution level.

At the moment, all DER units higher than 10 MW or group of RES/CHP connected at the same network node with a total installed capacity higher than 10 MW should be part of a generation control centre communicated with the system operator in order to follow dispatch and control orders. All of them should present a daily production program. Under constant feed-in tariffs, DER generators are allowed to deviate 5% without any penalty. Generators under premium on top of the market price have the same obligations as ordinary generators regarding production programs and energy imbalances. Aggregation is allowed to minimize program imbalances. The capacity limit which obliges DG/RES to participate in a generation control centre is expected to reduce from the current 10 MW to just 5 MW.

At the moment, the regulator is developing new DSO operating procedures (grid codes) and a Royal Decree to regulate the access and connection of “special regime” generators to the distribution networks (which in fact refers to DG). The first drafts that are available at the National Energy Commission website (www.cne.es) do include several provisions regarding DG. However, DG seems to be still considered as rather a passive element to help in grid operation. For example, congestion management at distribution level by DG curtailment is included in the procedures, albeit reducing a demand-driven congestion by increasing DG production does not seem to be considered.

Should ANM strategies be fully implemented, there exists the possibility to create new ancillary services to be provided at DSO level by DG. In this case the DSO should be able to meter at the local DG unit level. The provision of these ancillary services could be done through organized markets at the DSO level or through bilateral agreements between DSOs and DG. In this second alternative, some standard contracts would be desirable to increase the transparency of the system. Finally, it cannot be neglected that demand response ought to play a relevant role in ANM as well (see subsection 7.4).

8.7 Supporting innovation in DSOs

Under the current regulatory framework for distribution, (if any at all) there do not seem to be strong incentives for innovation. As previously explained, no Spanish DSO has currently implemented elements of active network management. However, there are funding possibilities outside the revenue cap regulation for performing innovation activities. There is a national program where demonstration projects are funded by the Ministry of Industry together with private companies[29]. Research in this field is also contemplated as a European research priority line known as Smart Grids under the 7th Framework Programme.

Including explicit incentives for innovation within the regulation of DSOs is recommended to efficiently integrate DG/RES and reward the most innovative DSOs. Incentives for innovation may be designed as input incentives (including these costs in the allowed revenues), similar to the UK's IFI, or output incentives (including more performance indicators to the revenue cap formula besides continuity of supply and energy losses) such as the RPZ in the UK. It is worth remarking that nowadays there is no clear consensus as to how to implement efficient innovation from DSOs. Therefore, it seems that different regulatory mechanisms should be tested and evaluated. OFGEM has recently created an initiative named RPI-X@20[30] which will review the whole regulatory framework of network industries and propose future regulatory recommendations.

8.8 Network planning

In subsection 8.5, it was stated that economic regulation of DSOs should consider the impacts of DG on distribution costs. In fact, the new regulatory framework for distribution that is being implemented is claimed to include the impact of DG on distribution costs. However, it is not clear how DSOs should benefit from the opportunities DG may offer. Due to the unbundling requirements imposed by the EU Electricity Directive 2009/72/EC, this is a particularly complicated task.

Nowadays, DG is mainly neglected in planning strategies. DSOs are obliged to connect all generation units, including DG, to their network. If any network upgrade is required to connect a new DG unit, it is done and recovered by the deep connection charges. However, any benefit that DG could produce is either not realised or not shared with DG operators.

As mentioned before, new distribution grid codes are being developed. Some preliminary drafts have been made available by the National Energy Commission. One of them is about distribution planning criteria. Therein, it is stated that DSOs should at least take into account two scenarios when planning the expansion of their distribution networks: peak (net) demand and peak (net) generation. Note that this coincides with the term snapshot that has been used in WP4 and WP5 of the IMPROGRES project. Moreover, this grid code, as it stands now, mandates that the most unfavourable conditions concerning DG are to be considered. This proposed network planning strategy would yield similar results to the ones obtained in the calculations of IMPROGRES WP4. However, WP5 results showed that achieving a more active role of DG and loads could significantly decrease distribution network costs. Savings computed for the Spanish case study were in the range of 2-8 %.

When connecting new DG/RES-E capacity the DSO ideally needs to balance the costs and benefits of two options: expanding existing deep network capacity or postpone this investment and incur higher congestion costs resulting from the bottlenecks that may be produced in the network. Therefore, a

[29] More information at http://www.ingenio2010.es/?menu1=&menu2=&menu3=&dir=&id=En
[30] More information at http://www.ofgem.gov.uk/Networks/rpix20/Pages/RPIX20.aspx

planning criterion that encourages DSOs to consider only the most unfavourable conditions for DG, albeit simple, is deemed excessively conservative.

Therefore, it is recommended that the regulator allow DSOs to be innovative in the way they incorporate DG in network planning and provide them with incentives to do so. This can only be achieved by modifying the passive role that nowadays is still played by loads and DG units. It would be unfair to place the whole responsibility on DSOs. Hence, regulation should also aim at enhancing the role of DG, even performance indicators could be thought of for DG together with penalties for non-compliance. This could be done via long-term bilateral agreements between DSOs and DG as the scheme described in (Trebolle et al. 2010).

8.9 Conclusions

The previous review has shown that a significant share of DG/RES has been already connected to the Spanish distribution grids. Nevertheless, significant increases in DG/RES capacity are expected for the coming years. The most relevant technologies will be on-shore wind, solar PV and high-temperature solar thermal.

The integration of these technologies in power markets is crucial due to the moderate increases in electricity demand expected for the next years and the lack of interconnection capacity with neighbouring systems. This integration has been especially successful for wind energy owing to the existing FIP scheme. For those controllable generators (CHP, biomass, biogas) that are not willing to trade at the wholesale market, mainly because that is not their core activity, further temporal differentiation could be introduced in the FITs. Integrating small units could be achieved through aggregation which, in spite of being allowed by current legislation, is not widely developed yet. Meanwhile, communicating DG units with control centres, which in turn communicate with the TSO control centre for RES undoubtedly would increase the visibility of these generation units and minimizes their negative impacts. The move towards integrating solar PV in populated areas is deemed appropriate too.

Growing shares of intermittent generators may cause balancing power need to increase, albeit this has not been the case for now. This challenge can be dealt with by promoting the installation of more flexible peaking generators, installing pumped-hydro storage, reducing the gate closure time or incorporating controllable DG/RES into balancing markets. Given the Spanish context, pump hydro plants and fostering DG/RES to participate in balancing markets are regarded as the most likely options.

Furthermore, the support payments for RES and CHP have contributed to creating a tariff deficit. Regulatory changes are needed to address this problem. Nonetheless, regulatory instability that may endanger the future development of DG-RES should be avoided to the maximum extent possible.

The substitution of traditional meters by smart meters is being carried out at the moment and will not be finalised until 2018. This is critical to ensure demand response which is presently nearly non-existent. In the meantime, demand response programs ought to be defined and progressively implemented, carefully defining the role of each of the agents involved. This is bound to require an important change of mind in the way electricity consumers behave. Additionally, electricity prices sent to consumers should reflect its true costs (avoiding protective regulated tariffs), the retailing sector should be fully developed and home automation ought to be developed and promoted.

Concerning the economic regulation of DSOs, a number of recommendations have been given. Firstly, it is advised to review and evaluate the methodology through which the impacts of DG in the different distribution areas are considered when setting their allowed revenues and regulatory incentives. Concerning network charges, DG should pay transparent and regulated shallow connection charges and cost-reflective UoS charges. This cost-reflectivity would imply a time and location differentiation in the UoS charges, included in the access charges. The Electricity Act, as it stands now, states that generators do not pay UoS charges and that all consumers should pay the same UoS charges regardless, of their location. Hence, this recommendation would require modifying the law.

Active network management is far from current operational practices. Not only is demand totally passive as previously described, but also DG does not play a truly active role either. Therefore, operational procedures (grid codes) for distribution congestion management and DG voltage control should be developed. The visibility of DG via control centres and network automation should be enhanced. All this could allow DG units to provide ancillary services at distribution level either through locally organised markets or by bilateral contracting between DSOs and DG operators.

Distribution network planning is done according to a “fit-and-forget” paradigm concerning the connection of DG. It is recommended that regulators allow DSOs to be innovative in the way they incorporate DG in network planning through the adequate incentives. Moreover, regulation should also aim at promoting DG units to adopt an active role with regard to network needs and share the costs and benefits they may cause to the system. This could be done by means of regulatory incentives/penalties or through long-term bilateral agreements between DSOs and DG operators.

Finally implementing ANM and incorporating DG in distribution network planning may require significant innovation from the DSO side. In order to achieve this, it is recommended to include specific incentives for innovation into the existing incentive regulation scheme. Nonetheless, there is no clear “best practice” as to how to do this in practice. Therefore, different regulatory mechanisms should be discussed, tested and assessed.

9 REGULATORY STRATEGY FOR THE UK

This chapter describes the regulatory strategy within the United Kingdom (UK). In a first stage, currently implemented DG/RES support mechanisms are addressed followed by commonly implemented system integration strategies of DG/RES. Besides that, regulation of DSOs regarding innovation incentives towards active distribution network management is discussed.

9.1 DG/RES support mechanisms

Renewable obligation and Renewables Obligation Certificates

The main support scheme for DG/RES in the UK is defined by the Renewables Obligation (RO), which characterises a quota system with tradable green certificates known as Renewables Obligation Certificates (ROCs). In general, the scheme is maintained by the electricity regulator in the UK (Office of Gas and Electricity Markets, Ofgem, http://www.ofgem.gov.uk).

The RO has started in England, Scotland and Wales in April 2002 and was implemented in April 2005 in Northern Ireland[31]. This support scheme is secured to last until March 2027 and might be expanded by the UK government[32]. There is currently no limitation in place for DG/RES units in general. However, from April 2010, it is proposed that plants under 50kW of electrical capacity will no longer qualify for support under the RO scheme, but will instead be moved towards a Feed In Tariff mechanism. The technologies taken into account by the RO include: Wind energy, biomass, solar photovoltaic, hydro and anaerobic digestion (compare e.g. Gipe, 2009).

The RO was originally designed on a technology neutral basis, whereby one Renewable Obligation Certificate is foreseen for every MWh of generated renewable electricity. From April 2009, the RO has been changed; the number of ROCs awarded per MWh is now dependent on technology specific parameters. As a consequence, some technologies get increased and others decreased ROC support. The currently ongoing project RE-SHAPING (http://www.reshaping-res-policy.eu) gives a detailed description of ROCs and corresponding support values. There is no minimum or maximum price for ROCs. The price is determined by the market. The value of a ROC is dependent on the price that a generator can achieve for trading their ROCs.

Climate Change Levy Exemption

The Climate Change Levy (CCL) is an environmental tax on non-domestic users of electricity. The main reason of CCL is to increase the energy efficiency and to reduce CO_2 emissions. Thus, DG/RES units are not applicable to this tax. The Treasury takes the policy lead on the CCL mechanism (http://www.hm-treasury.gov.uk) whereas the guidance for generators and suppliers on the CCL and the CCL exemption for renewables is published by Ofgem.

The levy in 2009/10 is set at £4.70/MWh and is amended according to yearly inflation. Levy Exemption Certificates (LECs) are administered by Ofgem for eligible DG/RES and renewable electricity generation.

[31] For details see: http://www.ofgem.gov.uk/Sustainability/Environment/RenewablObl/Pages/RenewablObl.aspx
[32] Details can be found at: http://www.decc.gov.uk/en/content/cms/consultations/elec_financial/elec_financial.aspx

Feed-in Tariff

As already mentioned, the UK Government is considering on the introduction of a Feed In Tariff scheme for renewable generation capacities. The scheme will be maintained again by Ofgem.

Therefore, the FIT scheme has to be seen as a planned instrument, and is expected to become operational on 1 April 2010. No end date has yet been clarified, however the FIT will provide support for up to 25 years (technology specific). Furthermore, the Government plans to perform a review of the FIT scheme going in-line with the review of the RO "amendments" discussed above. Necessary changes regarding this review are planned to be implemented in April 2013.

9.2 System integration of DG/RES

Country specific definitions (compare: The Distribution Code, 2006)

The distribution system operates at nominal voltages between 66kV on medium and 230 V on low voltage level. The 132kV network in England and Wales is also classified as part of the distribution system, unlike in Scotland. The distribution system provides electricity supply to customers for industrial, commercial and domestic purposes. The voltage of the connection depends on demand, the purpose for which the supply is used and the local technical requirements of the distribution system.

The distribution code covers all material technical aspects relating to connections to and the operation and use of the distribution systems of the Distribution System Operators (DSOs). It is prepared by the DSOs and is specifically designed to:

- Permit the development, maintenance and operation of an efficient coordinated and economic system for the distribution of electricity.
- Facilitate competition in the generation and supply of electricity.

Grid Access for DG/RES

A Distribution System Operator in the UK has the duty to connect DG/RES to the grid on request as described under section 16 of the Electricity Act (see Electricity Act, 1989). Furthermore, a DSO is obliged to make a connection offer to distributed generators, within three months of receiving a valid application. During 2006, 135 connection offers were made by the DSOs for a total capacity of 2GW.

Customers are allowed to seek competitive quotations for some of the works required to make a new connection to the electricity distribution system. The work involved in providing new grid connection lines can be split into two categories. The first category is the "Non-Contestable" works. These works can only be undertaken by the host network. The second category is competitive which implies that it may be undertaken either by the DSO or by an accredited Independent Connections Provider (ICP).

Works which can only be carried out by the DSO are as follows[33]:

- Assessing how the connection will affect the network
- Planning the type of connection required and specifying the materials to be used
- Deciding the point of electricity connection to the network (known as a POC)
- Connecting to the network
- Entering into legal agreements with third parties for the installation of electrical cables and overhead lines on their property

[33] See: http://www.edfenergy.com/core/smallservices/downloads/edfenergynetworks-connections-your-choice.pdf

- Repairing any faults with the connection and maintaining supply of electricity
- Approving any design work that has been carried out by an Independent Connections Provider
- Inspecting, monitoring and testing any work done by an Independent Connections Provider

Grid charges for DG/RES: One-Time-Charges and yearly fixed charges (non-output-related charges)
Distribution network operators are required to publish their charging methodologies and charges. A summary of charges made by all the DSOs can be found on the website of the Energy Networks Association at http://2008.energynetworks.org/use-of-system-charges/.
As an example, North West Electricity (formally United Utilities), DSO for the North West of England charges which came into effect on 1 January 2008 are set out below (for details compare Electricity North West Limited, 2008):

- *Asset annuity charge* – An annuity charge based on 80 percent of the total cost of the reinforcement works required to connect the distributed generation plant, over a 15 year life, with a rate of return of 6.9 percent.
- *Capacity Charge* – A standard EUR 2.16 (£1.50) per kW per annum of generation capacity installed.

Grid charges for DG/RES: Use of System Charges (Energy/Power related charges)
A standard €1.44 per kW per annum of installed generation capacity of the distributed generation plant installed is charged to recover the allowable operation, repair and maintenance on the sole use and reinforcement assets of the connection. These rules are applied to reinforcement costs up to a cap of £200 per kW of installed generation capacity. All reinforcement costs above this cap will be charged in full to the connecting generator along side other connection charges.

Balancing Services Use of System (BSUoS) charges

BSUoS charges are paid by suppliers and generators based on their energy taken from or supplied to the National Grid in each half-hour Settlement Period. These charges are paid to National Grid Electricity Transmission (NGET) to cover the costs of keeping the system in electrical balance and maintaining the quality and security of supply.

For a more detailed overview on system integration of DG/RES in the UK it is referred to (Orasch, 2009).

9.3 DSO regulation and support for innovation funding in the UK

There are 14 licensed distribution grid operators (DSOs) in the UK each responsible for a distribution services area. The 14 DSOs are owned by seven different groups. There are also four independent network operators who own and run smaller networks embedded in the DSO networks. The regulation authority Ofgem administers a price control regime that ensures that efficient distributors can earn a fair return on capital and operating costs whilst limiting the amounts that customers can be charged. Price controls are generally set for five year periods and the current price control runs from 1 April 2005 to 31 March 2010 (compare e.g. Pollit, 2007).

The UK has long tradition in regulating its electricity distribution grids based on incentive regulation models. Already in 1995 the regulator 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 distribution grid infrastructure have become increasingly obvious. Moreover, in the UK empirical evidence has become increasingly visible on the reluctance of investments into the 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 generation technologies. More precisely, the two dimensions of changes of the incentive regulation model in UK are as follows:

- the philosophy of allocating DG/RES grid integration cost has been changed from deep to 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 cost for DG/RES 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), Auer (2007b)):

- Same Boundaries on both Ends of the Grid: Prior to April 2005, demand and generation customers were charged differently on distribution grid level. DG/RES 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).[34] In April 2005, a common connection boundary has been introduced across generation and demand, i.e. new DG/RES generators connecting to the distribution grid now also pay shallower connection charges.
- Socialisation of Integration Cost: Distribution grid operators are allowed to recover their grid-related connection and integration cost of DG/RES generation facilities directly in the distribution grid tariffs by a combination of pass through (80% of connection cost) and an incentive per $kW_{DG/RES}$ connected (2.16 €/$kW_{DG/RES}$ (singular) and 1.44€/ $kW_{DG/RES}$/yr (annually)).

- Innovation Funding Incentive (IFI): The Innovation Funding Incentive (IFI) is intended to provide funding for particular DG/RES 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 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 cost 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 generation facilities to distribution grids. RPZs are intended to encourage distribution grid operators to develop and demonstrate new, more cost effective ways of connecting and operating DG/RES generation facilities. For licensed RPZs, the

[34] 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.

incentive element per $kW_{DG/RES}$ of DG/RES generation facility connected is increased for the first five years of operation from 2.16 €/$kW_{DG/RES}$ to 4.3 €/$kW_{DG/RES}$.

9.4 Recent Active Network Management initiatives

Recently, the energy regulator Ofgem has proposed that there will be a better customer service due to maintenance of high grid reliability by the DSO. Planned measures will add an average of ~4.5 € a year to demand electricity bills (compare Ofgem, 2009). This funding proposal includes upgrades of grids which were largely built between 1950 and 1960, as well as a strong incentive for developers to invest into low-carbon technologies. Therefore, Ofgem announces (Ofgem, 2009) in detail:

"The proposals, approved by Ofgem's governing authority, include ambitious new incentives and other measures to reduce carbon emissions. Companies will have strong incentives to connect up to 10GW of low-carbon generation to their networks over the next five years and improved incentives to cut network losses – currently at a level equivalent to the electricity used in about six million homes. Ofgem is proposing a new £500 million Low-Carbon Networks Fund to support large-scale trials of advanced technology including smart grids, and new commercial arrangements with customers. These advances will help the networks to accommodate growth in local generation, electric vehicle use and other developments anticipated in a low-carbon economy. In return for higher prices Ofgem requires the companies to deliver an even better deal for customers. The companies will earn additional rewards for outstanding customer service but face penalties for poor service. And there will be tough new standards on new connections. Companies will be penalised and have to pay compensation unless they significantly improve their existing connections service."

These proposals have been reviewed by independent consumer representatives named the "Consumer Challenge group" in order to represent consumer priorities in the context of active grid development and implementations.

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