Integration of electricity from renewable energy sources into European electricity grids

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Table of Contents

List of Tables

List of Figures

1 Summary

Europe is substantially committed to increase the contribution from renewable energy sources (RES) to total energy consumption. In the next ten years, the share of RES in the electricity market is expected to rise from 21% today to 35%. A further growth is anticipated and desired in the period after 2020, as the longer-term objective is to decarbonise the electricity sector in a sustainable way.

The ambitious plans for the development of electricity from RES pose three major challenges. Firstly, renewables change the geographical distribution of generation centres compared to the load centres. Secondly, a share of the renewables will be connected to distribution grids and will thus change the vertical distribution of generation. Thirdly, wind and solar energy are two dominant technologies which depend directly on the natural supply of renewable energy and thus are variable and intermittent energy sources. This report addresses the most relevant measures which can be taken in order to deal with these challenges.[1]

Regarding the expansion of transmission systems, different scenarios and concepts are currently under discussion. The European Network of Transmission System Operators for Electricity (ENTSO-E) has published a network development plan for up to 2020, whereas other scenarios look into the significant challenges for the developments of the electricity networks over longer periods, which might even include stronger connections to Northern Africa.

Today, conventional power plants are already supporting the management of the grid by providing balancing and reserve power. This practice could be extended significantly in order to support the integration of RES. For this purpose, gas-fired power plants, which are expected to increase their share in fossil power generation over the next decades, are the most suitable option.

Similarly, RES-E power plants are already supporting system stability in extreme cases today through downward regulation and other means. Modern inverters and centralised control of RES-E generation can extend the flexibility provided by RES-E power plants in the future. However, curtailment of renewable energy generation should only be the last resort, as it reduces the usage of renewable energies.

Another supply-side option for supporting RES integration is the expansion of energy storage. In contrast to other flexibility options, many storage technologies can store energy for long durations up to seasonal storage. However, the potentials for classic pumped hydro power storage are largely exploited and it is not yet clear whether and how new storage options can become viable in economic terms.

Finally, the integration of RES can also be supported by Demand Response measures. Shifting demand to periods where sufficient or excess renewable energy is available will help the management of a system dominated by renewables. However, the poten-

[1] Measures related to the distribution grid have not been addressed in this report.

tials for Demand Response are limited due to a lack of acceptance by consumers and the costs for making demand-side measures available for system management. Furthermore, Demand Response can typically span only short periods of a very few hours or less. Nevertheless, optimistic scenarios assume that up to 20% of the peak load might become flexible.

In order to support a future classification of the ability of regional electricity systems to integrate high shares of renewable energy, a set of indicators has been proposed. These include the level of balancing power available in the system, the margin of short-term backup power and the margin of longer-term secured capacity. More research is needed to further develop these indicators and their relation to the development of the transmission systems, and to make them useable across Europe.

The overview of options shows that while grid expansions and reinforcements and the development of new storage options will be the major measures for accommodating high shares of RES into European electricity systems, the further options of increasing the flexibility of conventional power generation and of the demand side also have the potential to make a significant contribution. An intelligent combination of the available options will reduce the need for expensive and time-consuming grid investments.

2 Introduction

This final report is submitted to the European Environment Agency in fulfilment of Task 2.8.2 – Renewable Energy of the EEA European Topic Centre on Air and Climate Change 2010 Work plan. The work is performed by Öko-Institut with guidance from Hans Eerens of the Netherlands Environmental Assessment Agency (PBL), and David Owain Clubb of the European Environment Agency.

One of the major objectives of European energy policy is a significant expansion of the share of renewable energy in the supply mix. In Directive 2009/27/EC, EU Member States have agreed to binding national targets for the year 2020 which are equivalent to an overall share of renewable electricity, heating and cooling and renewable energy in transport of 20 % of the overall final energy consumption. Most experts expect that within this overall target, the share of renewable energy in electricity production in the EU will increase from 21 % today to approx. 35 % (Eurostat 2010, pp. 146-147). Under the longer-term objectives to further reduce carbon emissions in Europe it is likely that the electricity sector will have to be nearly completely decarbonised by the year 2050, and this could mean shares of renewable energy in electricity production of up to 80 %, depending on the share of nuclear and CCS technologies (ECF 2010).

In most scenarios on the future of Europe's electricity supply, a large part of the projected increase in renewable electricity will come from wind power (onshore and offshore) and from solar energy (photovoltaics and solar thermal power, which may include imports from Northern Africa in the longer term). The use of sustainable biomass will also make a relevant contribution to the expansion of renewable electricity generation. In the baseline scenario presented recently by the European Renewable Energy Council (EREC), the share of fluctuating renewable energy (mainly wind and solar energy) is expected to reach 17 % in 2030 and 24 % in 2050. In advanced scenarios the share of fluctuating RES increases to approx. 30 % in 2030 and 50 % in 2050 (EREC, Greenpeace 2010).

Wind and solar energy are resources which depend on the real-time supply of renewable energy and thus are variable in their energy supply. An energy system which relies largely on variable renewable energy production has to provide sufficient supply capacity even in times of low renewable energy supply and deal with rapid variations in energy supply. The effects of variability can be smoothened if the wind and solar energy plants are distributed across large areas (see figure 1 below) and the methods of forecasting the wind and solar energy production have made significant progress in recent years. Through reliable forecasts, the market value of renewable electricity can be increased significantly and costs for balancing power can be reduced.

Nevertheless, it is clear that the large projected shares of wind and solar energy pose a significant challenge for Europe's electricity system. There is no doubt that the degree to which these two renewable energy technologies can be expanded will depend on reinforcements of the electricity grids and changes to its topology, on a higher flexibility of other parts of the power generation sector, on additional options for energy storage and on the flexibility which we can introduce on the demand side. It is thus vital to make significant progress in these areas in order to achieve Europe's objectives for expanding renewable energy and reducing carbon emissions.

This paper summarises the current status of the discussion on the integration of high shares of electricity from renewable energy sources into the electricity systems in Europe. It addresses the different options for increasing the ability of Europe's electricity systems to integrate high shares of wind and solar energy. Qualitative and quantitative scenarios are derived for the further development of these options and a set of possible indicators for describing the ability of national and regional energy systems to integrate variable renewable energy generation is proposed and discussed.

This paper presents a high-level overview. Its findings are based on an analysis of recent literature and data provided by European institutions. They are further supported by the results of interviews performed with selected experts (see chapter 11 for an overview of the interviewees).

Chapter 3 discusses the challenges for integrating large shares of renewable energy into European electricity grids and presents the analytical approach taken in this paper. Based on the structuring of the issue of system integration as shown in chapter 3.3, chapters 4 to 8 discuss five key measures for renewable energy integration:

- Reinforcing and adapting the transmission grid
- Increased flexibility of conventional plants
- Increased flexibility of renewable plants and Distributed Generation
- Expansion of energy storage

- Expansion of demand-side flexibility

It was not possible to cover issues related to distribution grids in this report. However, they should be addressed in future activities by the EEA, as the operation of the distribution grids can also contribute to the integration of renewable energy.

Chapters 4 to 8 follow a common structure:

- Firstly, the current situation is described and the major challenges in the further development of the measure are summarised.
- Secondly, the potentials for the measure are assessed and the related uncertainties are addressed.
- Thirdly, the relevant barriers are identified and adequate actions to overcome them are proposed.
- Fourthly, potential indicators for describing the progress of an electricity system in its ability to integrate large shares of variable renewable energy production are discussed.
- Finally, qualitative and, where possible, quantitative scenarios are identified which describe the potential future developments.

Some conclusions are provided in chapter 9.

3 The challenge of integrating renewable energy into the European electricity system

3.1 Scenarios for the development of renewable electricity production

In the context of the efforts to reduce greenhouse gas emissions as well as other energy policy objectives (energy security, reduction of energy import dependency, etc.), the share of renewable energy in the European electricity system is growing continuously. Electricity generated from renewable energy sources in the EU-27 countries rose from 310 TWh in 1990 to 526 TWh in 2007 (European Commission 2010b). More than 20% of this volume was provided by the variable resources wind and solar energy, and since then, their share has grown even faster.

Following the figures provided by the European Wind Energy Association (EWEA), the installed capacity of wind power in the EU was 75 GW at the end of 2009 (EWEA 2010b). According to figures provided by the Joint Research Centre (JRC) of the European Commission, the installed capacity of photovoltaic power in the EU was 16 GW at the end of 2009.

In all scenarios for the future development of the European electricity sector, the largest driver in the projected evolution of renewable energy sources in the electricity sector is wind (Figure 1).

Up to 2020 the evolution of biomass is the second most important driver, while from 2020 to 2030 the evolution of solar power is more dynamic than biomass.

Renewable power generation already has the largest market share in total power generation in 2020 (26 %) in the EU Baseline scenario 2009[2] and is projected to account for almost one third of total generation in 2030. Alongside rising investment in offshore wind and solar photovoltaic power, biomass and waste input to power generation is projected to more than double in 2030 from current levels (European Commission 2010c, p. 28). In the EU 2009 Reference scenario[3] wind, solar photovoltaics and biomass see a major growth compared with the EU 2009 Baseline scenario. Due to the further implementation of the cogeneration directive, biomass is projected using a higher percentage than in the EU Baseline scenario 2009 (European Commission 2010c, p. 42).

The Power Choices scenario from Eurelectric and the IEA World Energy Outlook reference scenario expect a RES share of approximately 35 % in 2030 for Europe (Eurelectric 2009, IEA 2009b). While hydro power remains at 10 %, biomass increases to more than 5 % and wind power is expected to provide 15 % of the total electricity generation in 2030.

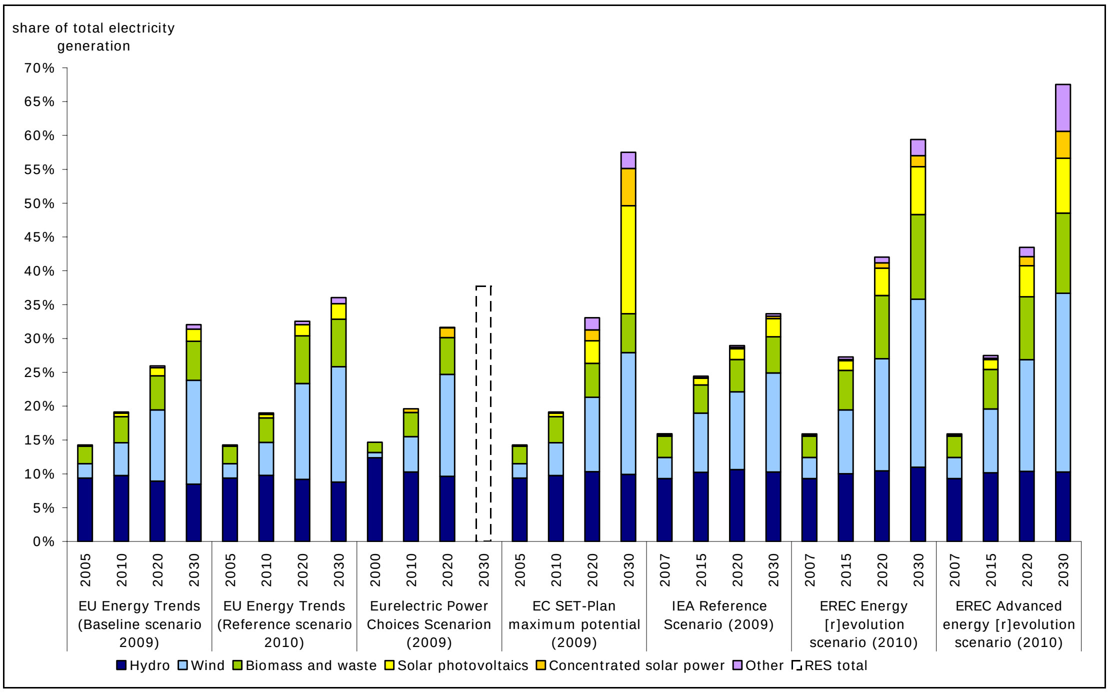

Figure 1: Projections of the share of renewable energy in total electricity generation in the 27 EU Member States.

Source: (EREC, Greenpeace 2010, p. 62-64; EURELEC-TRIC 2009, p. 56-63; European Commission 2007; European Commission 2010c, p. 67 + 125; IEA 2009b, p. 633)

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2 The Baseline scenario determines the development of the EU energy system under current trends and policies.

3 The Reference scenario includes additional policies and national targets under the EU Renewable Energy Directive 2009/28/EC and Decision No. 406/2009/EC on effort sharing.

The maximum potentials shown in the European Strategic Energy Technology Plan (SET plan) refer mainly to an extreme extension of solar photovoltaic and solar thermal power (European Commission 2007). The maximum potential for electricity generation from biomass and waste is significantly smaller than the projected increase in the EU-27 scenario based on the EC proposal without RES trading. The development of electricity generation from RES is in the IEA Reference Scenario between the EU-27 baseline scenario and the EU-27 scenario based on the EC proposal without RES trading (IEA 2009b, p. 633).

The "energy [r]evolution" scenarios published by the European Renewable Energy Council (EREC) and Greenpeace show wind power as the dominant renewable energy source in EU-27, followed by solar photovoltaic and solar thermal power plants in the more advanced scenarios (EREC, Greenpeace 2010, p. 62 - 64).

The baseline scenario of the SET plan forecasts a total capacity of wind power of 120 GW in 2020 and 148 GW in 2030. In its more ambitious scenario, the SET plan foresees a range of up to 180 GW of wind power in 2020 and up to 300 GW in 2030. Compared to this, EWEA expects that by 2030 a total capacity of 400 GW of wind power could be installed in Europe, of which 250 GW would be offshore (EWEA 2010a).

Regarding solar energy, the SET plan expects a photovoltaic capacity of 9 GW_p in 2020 and 16 GW_p in 2030 in the baseline scenario. In the ambitious scenario, these values could rise significantly to 65 – 125 GW_p in 2020 and 300 – 665 GW_p in 2030. With regard to concentrated solar power (CSP), the SET plan assumes that all plants are equipped with thermal storage and are thus not regarded as variable energy production.[4]

All these scenarios underline that the share of variable and intermittent electricity production from wind and solar energy will grow significantly. Therefore there is an urgent need to prepare European electricity systems in time for the challenges of integrating these energy volumes.

3.2 Challenges of renewable electricity integration

Besides just installing renewable energy capacity, it is important to also develop and design the entire electricity system in order to allow for the integration of high shares of renewable energy. The increasing share of renewables poses three types of challenges to the electricity system:

a) <u>Geographical distribution:</u> Renewable energies are triggering changes in the geographical distribution of electricity generation, and the transmission network needs to be adapted accordingly. The geographical distribution of renewable energy on the one hand and demand on the other hand often do not coin-

[4] The baseline scenario of the SET plan sees no significant CSP capacity to be installed in EU27. The ambitious scenario includes some 5 GW of CSP installed in Europe and up to 36 GW imported from the Mediterranean region by 2030.

cide, nor are renewables necessarily located close to current generation centres. This is especially true for offshore wind parks and concentrated solar power deployed in desert areas.

b) Distributed generation: Small-scale installations of renewable energies, like photovoltaic panels on buildings, are connected to the distribution grid. Together with small-scale CHP plants, they are usually categorised as distributed generation (DG). An expansion of these plants changes the vertical distribution of generation within the grid infrastructure: While in the past most generation was connected to the transmission grid, the increasing share of DG can cause problems for the distribution level that was designed for serving load customers (e.g. bidirectional flows). This aspect will not be discussed further in this paper, as the largest part of the future renewable capacity will not be connected to the distribution network.

c) Variability and intermittency: Wind and solar power plants have an uneven electricity feed-in, which depends on the availability of wind and solar radiation. Generation is therefore

   - highly variable and also intermittent,
   - not flexible,
   - and the forecast of solar radiation and especially wind speed and thus electricity generation is inherently difficult.

The term “variability” is used in this paper to denote the (short-term) variations in wind and solar energy generation, which can be analysed in forecasts. However the actual energy production might deviate from the forecast. The term “intermittency” is used to describe the fact that the power generation from wind and solar energy is following (longer-term) variations which might include longer periods of very high or low production. Although these periods might be announced through forecasts, the energy system must still be able to cope with low (or high) production periods.

Both variability and intermittency are relevant problems because electricity generation needs to match demand second-by-second. As a consequence of these characteristics, different options need to be available to compensate the fluctuations of renewable energy generation. In order to deal with errors in the forecasts for wind and solar energy production, short-term measures for frequency and load flow control (primary and secondary reserve) are required. In contrast, the long-term variability of renewable energy generation needs to be counterbalanced though longer-term measures, which are needed to support the electricity system, e.g. in the case of a continuous calm which cuts down wind generation over several hours or days.

When assessing the demand for balancing options, especially in terms of short-term balancing and frequency control, it should also be taken into account that electricity generation from renewable energy sources not only causes additional balancing demand, but also replaces conventional plants and their balancing capacity, which is currently being used to manage the electricity grids in the case of unexpected changes in demand or supply.

3.3 Measures supporting the integration of renewable energy

There are different options for reacting to the challenges presented in the previous section. This includes conventional options, like reinforcing transmission grids and conventional storage, but also new options that tend to be more distributed and are part of the Smart Grid concept, e.g. demand-side flexibility. An overview is given in

Table 1 below.

A first option is the extension of the transmission grid (measure 1 in

Table 1). This is necessary to remove bottlenecks between future renewable generation centres and regions with high energy demand, but can also contribute to managing the variability of renewables by connecting wind generators in a larger area. This strategy can be based on gradual reinforcements and extensions of the existing grid infrastructure, but it might also include the development of a “supergrid”, using, for example, High Voltage Direct Current (HVDC) connections. Note that due to a lack of investments in the recent years, quite a number of investments in the transmission grid, mostly relating to interconnectors between regional control areas, would be required even without a further expansion of wind and solar energy.

As for renewables connected to the distribution grid, grid upgrades can also be required (option 2). Furthermore, intelligent networks on the distribution level, which aim at integrating distributed generation into network control rather than only connecting these plants, can enable the grid to accommodate more distributed generation (option 3). As this paper does not address the distribution grid level, these two options are not discussed further.

For managing the variability of renewables, the most important option besides transmission grid upgrades is to increase the flexibility in the generation system. This includes the conventional option of increasing the flexibility of fossil and nuclear power plants (option 4). Another possibility is to increase the flexibility of renewable plants and distributed generation, so that these can react to system requirements, too (option 5). Flexibility can also be provided on the supply side by storage technologies (option 6). Finally, flexibility on the demand side can also contribute to managing variable generation (option 7). These options can contribute to replacing conventional network and generation investments and overcome operational constraints.

In the following table, the integration challenges presented in the previous section that arise from a changing generation structure and an increasing share of renewable energies are shown in the first row, while potential measures for solving them are listed in the first column. The cells of the table show how the measures can be related to the challenges. The first column also indicates which chapters of this report are addressing the respective measure.

It should be noted that there are different measures which can provide additional flexibility to the electricity system such as higher flexibility of power plant operation, additional energy storage capacities and demand-side flexibility. Under ideal market conditions, for example on a balancing market, these could compete on an economic basis, i.e. the lowest cost options should be used.[5]

Table 1: Challenges of renewable electricity integration and related measures

<table>
<tr><th><u>Challenges</u>

<u>Measures</u></th><th>a) Changing geographical distribution of generation</th><th>b) Increasing share of distributed generation (DG) connected to the distribution network</th><th>c) Increasing share of variable and intermittent generation</th></tr>
<tr><td>(1) Expansion of the transmission network, potentially including a changing network topology (“supergrid”) (chapter 4)</td><td>Adapt grid structure to connect new generation and demand.</td><td>Can generation in the distribution grid reduce the demand for transmission capacity?

Expansion relevant only locally where transmission grid is expanded to take up more electricity from the distribution grid.</td><td>Adapt grid structure to enable improved balancing between intermittent generation, e.g. levelling-out wind generation in different areas.</td></tr>
<tr><td>(2) Expansion of the distribution network (not covered here)</td><td></td><td>Increase network capacity to accommodate DG.</td><td></td></tr>
<tr><td>(3) Intelligent (distribution) networks (not covered here)</td><td></td><td>Increases capacity of existing network to accommodate distributed generation.

Can be an alternative to measure (2): expansion of the distribution network.</td><td></td></tr>
<tr><td>(4) Increased flexibility of fossil and nuclear plants (chapter 5)</td><td colspan="2">Increasing share of renewables replaces spinning reserve of fossil and nuclear plants. This needs to be substituted.

Flexible fossil and nuclear generation can also help deal with transmission bottlenecks.</td><td rowspan="4">Increased share of variable and intermittent generation needs to be counterbalanced by higher flexibility elsewhere in the system.

This flexibility can partly be provided by fossil and nuclear plant capacity or new flexibility provided by renewables and DG to the extent possible. These options compete against storage and demand-side load management.</td></tr>
<tr><td>(5) Increased flexibility for renewables and small-scale plants where possible, e.g. via virtual power plants (chapter 6)</td><td colspan="2" rowspan="3">These options can help deal with bottlenecks in both the transmission and the distribution grid.</td></tr>
<tr><td>(6) (New) energy storage technologies (chapter 7)</td></tr>
<tr><td>(7) Flexibility on the demand side (chapter 8)</td></tr>
</table>

Source: *Öko-Institut*

This is true as long as there are sufficient options available under these measures. Should there be no more flexibility measures available at reasonable cost, the further

[5] It must be noted though that the European electricity market is far from being ideal.

expansion of renewable energy might have to be restricted. Thus it is vital to explore and develop all the measures listed in table 1 in order not to endanger the longer-term targets for the expansion of renewable energy.

3.4 Potential indicators for renewable energy integration

In order to assess the ability of the electricity system in a country or a group of countries to integrate large shares of variable renewable energy, two of the challenges mentioned in chapter 3.2 need to be taken into account:

- Changes in the geographical distribution of electricity generation
- Variability and intermittency of renewable energy production

As mentioned in chapter 3.2, a further aspect of integrating distributed renewable energy generation into the distribution grids is not addressed in this paper.

The technical flexibility of an electricity system can be determined based on the available load change ratio[6] on the generation side. The demand for flexibility due to the expansion of renewable electricity depends on the correlation of load changes on the demand side and the variations of electricity supply from wind and solar power plants on the generation side. In order to assess the combination of these aspects over time, a dynamic modelling approach would have to be used which reflects typical load and generation profiles. However, for the purposes of this paper, the analysis has been simplified to a static approach which assesses the secured capacity and the available total flexibility offered by all relevant options for helping the electricity system to deal with variable and intermittent renewable electricity generation. These factors are differentiated over three different timescales and allow the determination of a set of indicators which describe the extent to which the electricity system in a country or a group of countries is prepared to cope with the challenges of integrating renewable energy.

3.4.1 Indicator “Level of balancing power available in the system”

Today, the margin of balancing power needed to deal with unexpected variations in energy demand or with failures in power plants is provided mostly by spinning reserve in fossil-fuelled power plants. Primary and secondary control as well as minute reserve is provided by fast adaptations of the power production in these plants and thus help to stabilise system frequency and voltage. The expansion of renewable energy reduces the share of fossil-fuelled power plants operated in the system. Thus there will be a need to provide balancing power from other sources as described in table 1 of the previous chapter.

The indicator based on level of balancing power available in the system describes the ability of the system to adapt to sudden changes in demand and supply. It should be noted that there is a demand for balancing power even in the complete absence of

[6] The load change ratio is defined as the maximum share of installed capacity of a power plant or a group of plants which can be varied per minute.

variable and intermittent generation from RES. The indicator thus describes the extent to which the electricity system in question is able to maintain a sufficient level of balancing power in the course of displacing fossil power plants by renewable energy.

The level of balancing power which is available in any electricity system should be large enough to cover the sudden and unexpected changes in power generation and demand in that system which can reasonably occur.

3.4.2 Indicator “Margin of short-term backup power”

With a rising share of variable generation from wind and solar energy, the electricity system must be able to deal with short-term variations of the supply of electricity from RES. The methods for forecasting wind and solar power supply have been improved significantly in recent years and further improvements can be expected. For example, the day ahead forecast error for wind power in Spain decreased from nearly 25 % in 2005 to 15 % in 2008, while the short-term forecast error for wind power (4 hours ahead) is now less than 5 % (de la Fuente 2010).

The indicator “margin of short-term backup power” describes the ability of the electricity system to deal with the remaining error in the forecasts for wind and solar power generation. The time constant of this backup power is between 15 minutes and up to several hours. Since the short-term backup power is needed to cover unexpected deviations from the renewable energy forecast, it must be available at very short notice.

The margin of short-term backup power should be large enough at any time to cover the expected maximum short-term deviation from the forecasts for wind and solar energy in a certain region.

3.4.3 Indicator “Margin of longer-term secured capacity”

As wind and solar power depend on weather conditions, their power output does not only show short-term variations. Both renewable energies are also intermittent, which means that their production might fall to a very low level for a longer period, e.g. due to a long lasting calm period or heavy clouds covering the sky for several days. The effect of intermittency can be quite significant for a single plant at a certain location. As wind farms and solar plants in a larger region are connected to the same electricity system, their geographical dispersion significantly reduces the correlation of load changes (MottMacDonald 2003), see figure 2 Nevertheless, periods of low wind and/or solar production can occur for large parts of Europe and the electricity systems must be prepared for this extreme situation.

The indicator “margin of longer-term secured capacity” describes the ability of the electricity system to replace longer-term reductions in electricity production due to the intermittency of wind and solar energy. In principle, the reductions in energy generation will be known in advance due to current forecasting methods. Thus it is possible to schedule backup power plants, even if they have longer start-up times.

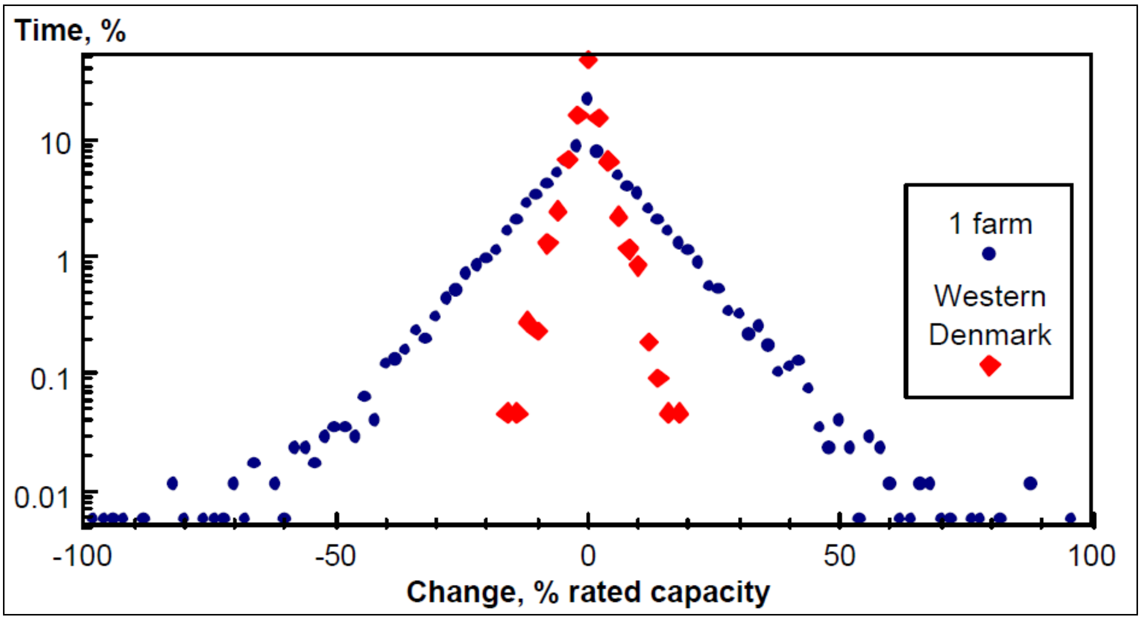

Figure 2: The smoothing effect of connecting wind farms over longer distances

Source: (MottMacDonald 2003)

The margin of longer-term secured capacity should be large enough in any electricity system to cover the difference between the average capacity of wind and solar generation and their secured minimum capacity. In principle the duration of the availability of the secured capacity must be unlimited. This means that flexibility options based on classic energy storage such as pumped hydro power and those based on demand side flexibility cannot only contribute to this margin depending on their storage capacity, which tends to be rather limited.

3.4.4 Indicator “Interconnection capacity”

This indicator describes the ability of the electricity system to transport electricity to various European regions and is connected to the integration or geographical scope of the energy market. It describes the ability of the grid to transport electricity in cases of surplus or shortages. Increased interconnectivity will also reduce the variation in electricity prices (geographically and in time). The indicator is defined as the interconnection capacity of an area (EEA/EU27/5-EU areas/country/TSO) with its surroundings divided by the generation capacity in that area.

3.4.5 Outlook on the application of the indicators

Further research will be needed to assess how the indicators mentioned above could be determined in detail and how their values could be evaluated. For example, it might be sensible to determine the indicators taking into account a certain threshold of costs for using the respective potentials for flexibility in the system.

Furthermore it should be noted that the indicators are defined here for a single region. They may be influenced by the available capacities of the transmission system connections to other regions.

The concrete options for providing the flexibility needed for the integration of variable and intermittent renewable energy into the electricity systems are described in more detail in chapters 4 to 8 which follow.

4 Reinforcing and adapting the transmission grid

4.1 Starting point and major challenges

From the earliest days of electricity supply over 100 years ago it has been necessary to transmit electric power from the generating plant to the load location. Very early on, this initial point-to-point transmission developed into relatively large networks interconnecting multiple load centres and sources of generation. Generating electricity is capital intensive, and it is generally much more economic to build transmission facilities to distribute electricity than to build additional generation. There are several reasons for this:

- Diversity in the times of maximum demand means that the interconnection of many load and generation centres results in an overall reduction in total generation required.
- The load centres and the cheaper sources of energy are often distant from each other. This may be particularly true for renewable energy resources (such as wind or hydro power) but it can also be the case for fossil fuel, e.g. a coal-fired station may be sited at a coal field, or a nuclear station sited away from population centres and near to adequate cooling resources.
- Interconnection facilitates higher utilisation of plant, since the capacity reserves needed to meet planned and unplanned outages can be shared across the network. Interconnection also strengthens a system's ability to recover from major faults.
- Providing access to many load centres means that power stations can be big (provided that the grid is of sufficient capacity) so taking advantage of the "economies of scale".

Although the earliest electricity distribution was DC (direct current), and promoted strongly by Thomas Edison, it soon became clear that with the technology then available AC (alternating current) was much superior, both technically and economically, for the large scale transmission and distribution of electricity. The principal reason for this is that AC voltage can be changed much more easily and cheaply than DC voltage – the electrical power transformer is an AC only device. Electricity loss in a transmission line is proportional to the current squared, and since for a given power transfer voltage is inversely related to current, energy loss is much reduced the higher the voltage of transmission/distribution. Transformation means that transmission can occur at several hundreds of kilo-volts, whereas the end-use happens at only a few hundreds of volts or less. With today's conversion technology between AC and DC, HVDC transmission can have advantages, both technical and economic, over HVAC transmission. These include transmission over long distance, particularly when using cables rather than overhead lines; connecting AC grids asynchronously; and in limiting system fault levels.

Over the years, as electricity usage has increased and been extended, networks have been merged, and in Europe today there are seven principal AC systems, of which five are connected together via HVDC links (below). The planning and operation of these systems is coordinated through the European Network of Transmission System Operators for Electricity (ENTSO-E), which consists of 42 TSOs from 34 European countries. The two transmission systems that are presently isolated from the other five are the islands of Iceland and Cyprus (ENTSO-E 2010).

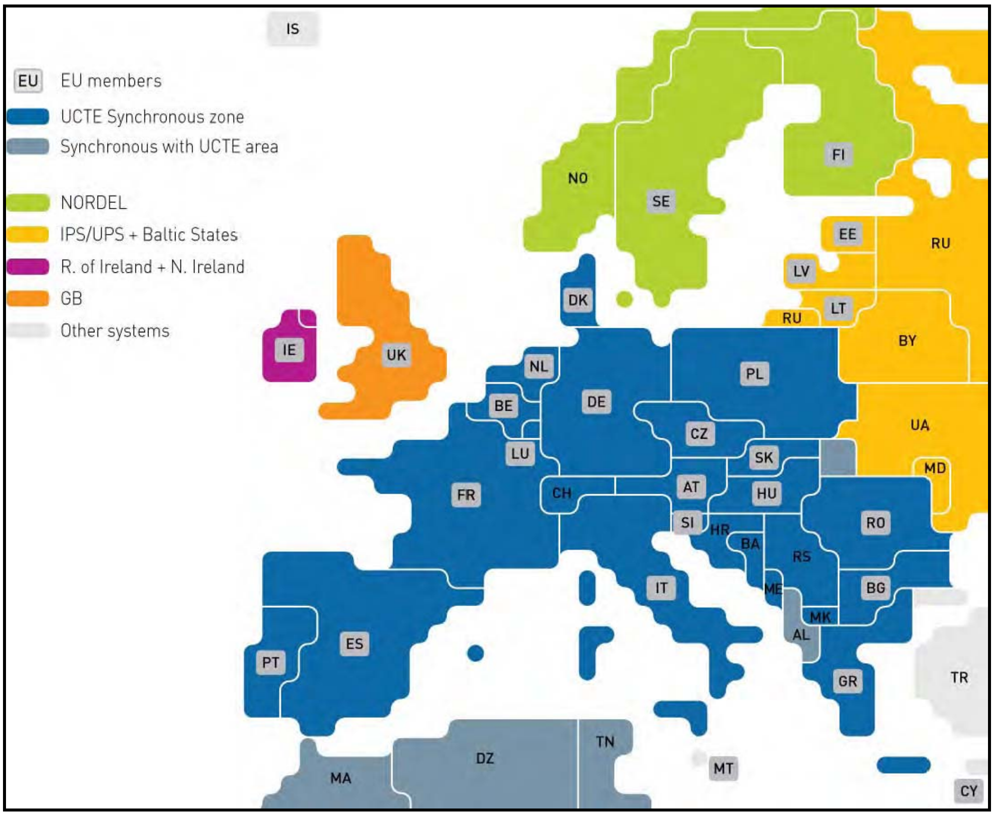

Figure 3: The five connected synchronous areas of the European grid
Source: (UCTE 2009b, p.6)

In AC networks the generators must remain synchronous at all times and to achieve this each network has to be electrically "strong". Stability cannot be maintained in an AC system unless the connections between generation groups are of sufficiently low impedance. As a result each of the seven systems is a meshed and relatively dense network. However, the maturity of the grid varies across the various nation states, each with its own limitations, even before considering the connection of renewable generation. There are already some extreme "hotspots", and problems can spill over from one country to another resulting in the implementation of "defensive measures", for example the possible use of inter-connection via HVDC on the Polish/Czech border with Germany due to the increased wind/solar volatility (interview Botting).

The five AC systems that are linked together are interconnected using HVDC which is necessary for one or more technical reasons. First of all it allows the connected systems to be joined asynchronously and means that the interconnection can be "weak" relative to the size of the AC systems. Secondly, if the interconnection is a long high voltage cable (an extended sub sea crossing, for example) then if operated at AC the reactive power loading (its charging current) would load up the cable and seriously limit its ability to carry real (i.e. useful) power. The use of HVDC also facilitates the scheduling of power transfers, since the conversion from AC to DC (and *vice versa*) is controllable, enabling the power transfers to be specified and maintained despite changing conditions on the AC networks.

In its Ten Year Network Development Plan (TYNDP), ENTSO-E notes that since 2002 total generation has been growing more rapidly than total load in the European networks – over the five years from 2002 to 2007 the increase in total generating capacity was about twice that of total load – which it attributes to the development of RES units with their high installed capacity and relatively low load factor compared with conventional generation. And this trend seems set to continue. The TYNDP identifies seven network investment needs clusters of which the top two are the integration of "massive" RES generation in the northern part of Europe (mainly wind) and in the southern part of Europe (mainly wind, hydro and solar) (ENTSO-E 2010, pp 37, 93). Figure 4 illustrates this situation.

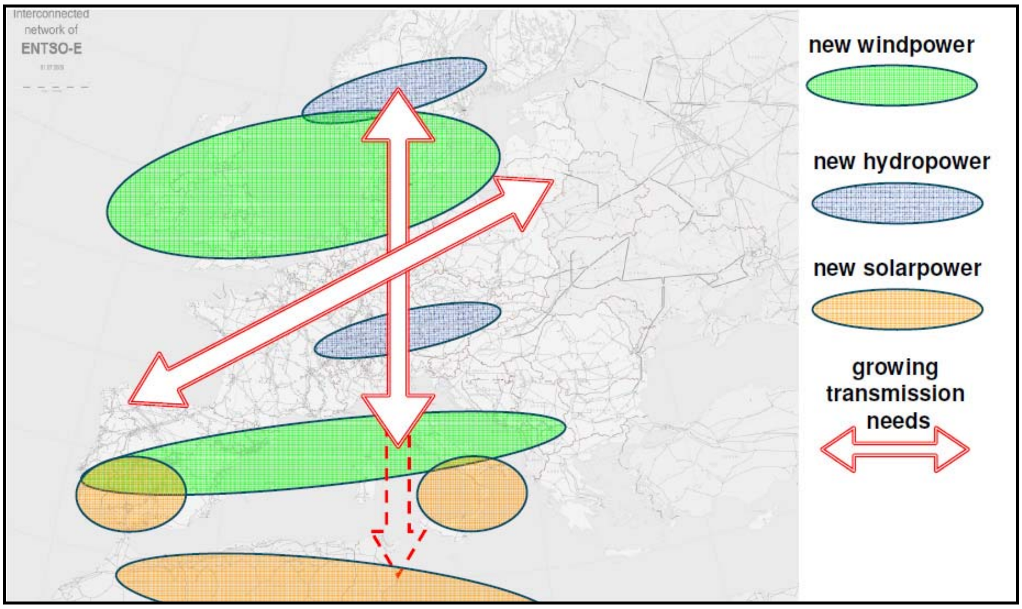

Figure 4: New renewable generation and transmission growth

Source: (ENTSO-E 2010)

The location of these energy sources and the rapid expansion in their exploitation present significant challenges to the development of the electricity grid in Europe.

As noted in chapter 4.1, installed wind generation capacity at the end of 2009 was 75 GW which in the most optimistic growth scenario could rise to 400 GW by 2030 of which 250 GW would be offshore. However, of the 75 GW in operation at the end of 2009, only 2 GW was offshore (EWEA 2009c). This initial development has been relatively close to shore, and can therefore be connected conventionally using alternating current (AC). But the substantial growth in offshore wind inevitably means moving further offshore, and as cable lengths approach 100 km AC technologies reach their technical limit and direct current (DC) becomes the only viable approach, both economically and technically (ENTSO-E 2010, p. 148).

However, although HVDC technology has developed in recent years, it is essentially only used in point to point applications[7], either for long distance transmission, or for the interconnection of AC grids which cannot be connected synchronously. The lack of a viable high voltage DC circuit breaker is the main factor preventing the development of DC grids (ENTSO-E 2010, p. 148).

Also, the conversion technology used so far has generally been CSC (current source conversion), but for this to function the AC side has to be a relatively strong AC system, something that is unlikely to be readily available at an offshore wind farm. Therefore the newer VSC (voltage source conversion) technology will be required.

So the development of offshore wind clearly presents significant technical challenges involving new or untried technologies – particularly related to HVDC – but also the very fact of connecting to large amounts of generation in a marine environment. And the resources to do this are limited. As things stand at the moment, there is simply not enough cable manufacturing capacity or sufficient installation vessels available to construct the required network (BWEA 2007).

4.2 Potentials and uncertainties

As noted in the previous section, the potential for the development of offshore wind will be limited without an increase in cable manufacturing capacity. This is particularly the case for export cables as can be seen in Figure 5. A significant increase in cable manufacturing capacity is required to keep pace with the projected demand. This is not the only supply chain issue identified in the BVG Associates report (BVG Associates 2009), though it is the one of most concern to offshore transmission.

[7] Some three terminal HVDC systems are operational, for example the SACOI link between Italy, Sardinia and Corsica.

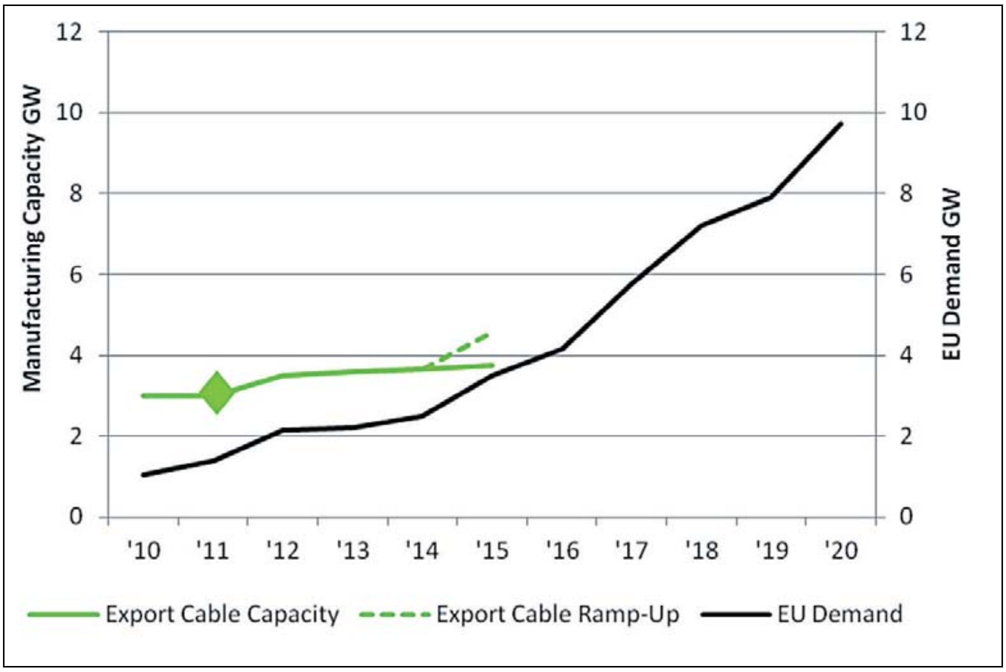

Figure 5: Projected export cable manufacturing capacity and European offshore demand

Source: (BVG Associates 2009)

It is difficult to assess the extent to which the various uncertainties with affect the potential of the grid to accommodate the renewable generation levels predicted by the various scenarios. There are technical uncertainties arising from the need to use HVDC on a much wider scale than before and to move to the relatively new VSC technology. There are also various construction issues. The HVDC converters take longer to manufacture and it may take 3.5 to 4 years from procurement to grid connection (BVG Associates 2009); cable laying and construction vessels will be in short supply and on long lead times; and working in the marine environment will make for scheduling uncertainties. Onshore there will be the risk of delays in getting consents and approvals, or in having them refused.

There is also uncertainty associated with the generation and load evolution scenarios. TSOs are notified of many developments which are uncertain, and those that do materialise may well get delayed. There should be a way that reliable and accurate information on investment in generation reaches the TSOs in a timely manner. And there is political uncertainty, especially given the international context regarding climate change goals and the effect these may have on European policies (interview Chaniotis).

The level at which renewable generation gets connected is similarly uncertain: offshore generation is obviously at the transmission level, but feed-in tariffs are also encouraging the connection of generation at distribution and domestic level, requiring a need to view things from an overall systems perspective. Increased infrastructure at the transmission level may be "over the top" if generation at the distribution level is acting as a “negative load” and reducing demand, but it could be too little if the distributed generation is spilling over onto the transmission system and adding to the transmission flows. We currently do not have sufficient knowledge of the interdependencies or sufficient skill sets to address the various issues (interview Botting).

The push to achieve higher penetration of renewables will go on, this will be mainly wind up to 2030 and renewables could eventually reach a 50% share in power geenration. The challenges are not so much technical, at least not onshore, but progress is slow to build new lines, which is mainly a planning and regulatory problem. Regulators tend to measure over the short term and look for minimum cost; cf: for example overhead lines are always favoured over underground cables because the latter are much more expensive. This purely economical valuation can result in very long delays because of public acceptance issues. Local political factors can also be a problem; for example, in Belgium the planning of renewables is a regional matter and not even coordinated at the country level – it is difficult to see how transmission can be planned in a rational way in such situation (interview van Hulle).

The major uncertainty is in the time it takes to get consents to develop high voltage links. It can take 8 to 10 years to develop and realise high voltage links and their associated substations – sometimes longer. This is in contrast to the development of wind farms or large power plants which can generally be achieved in only 3 to 5 years. It is therefore better to develop transmission corridors, rather than the grid itself, and be ready to invest in the grid as and when it becomes necessary. Political will is needed to nominate a person or authority to approve the corridors. In the Netherlands the law in this area was recently changed (National Coordination Regulation) and there is now a planning process (National Fitting-in Plan) which provides one cycle for national comment and approval, with the Ministry of Economic Affairs responsible for the final decision. Reconciling all the different kinds of interests and “not in my back yard” attitudes is ultimately a political process. Similar streamlined procedures need to be adopted Europe-wide (interview van der Meijden).

As well as needing new transmission to connect to the more remote renewable energy sources – potentially both onshore and offshore wind, and solar – the existing grid will need to be reinforced to facilitate the greater power transfers. Building new transmission is less socially acceptable than it once was, and projects can be subject to significant delays. Novel and unconventional technologies can make better use of existing assets by increasing the capacity of the existing grid. FACTs devices (flexible AC transmission) and PSTs (phase shifting transformers) reallocate power flow away from heavily loaded routes to more lightly loaded ones and so make a more optimal use of the transmission assets. The capacity of overhead lines can be increased by reconductoring with high temperature low sag (HTLS) conductors, and/or by implementing flexible line management (FLM), also known as dynamic line rating, which adjusts the line rating depending upon the actual environmental conditions and the physical state of the conductors (ENTSO-E 2010, pp. 146-147). The European Wind Integration Study (EWIS 2010) shows that this can enable up to 20% increase in thermal rating, and possibly 30% to 40% for very short time periods.

4.3 Barriers and requirements for action

In the previous section it has been noted that limitations of the supply chain could be a significant barrier to the development of the European grid. In particular, the capacity for manufacturing HV subsea cables is limited with only three companies established in the offshore market: Nexans, Prysmian and ABB – though recently NKT has entered the market – and production capacity needs to be substantially increased if offshore wind is to be developed as proposed. It takes about four years to build a new extrusion line and though suppliers have expansion plans, they will be unwilling to invest without being satisfied that projects will proceed. Also, subsea cables need to be loaded onto the installation vessel at the factory, limiting the number of sites where new capacity can be built. Manufacturers able to add additional capacity within existing factories can probably do so in 12-18 months (BVG Associates 2009).

Subsea cable installation is another area of concern, with a relatively small number of experienced installation companies and a high risk of cable damage.

Any development requires statutory consultation to obtain the necessary consents and this can be a lengthy and uncertain process. Onshore developments in particular can be subject to a very long approvals process. In fact, the main barrier to grid development is permitting – which is responsible for the bulk part of the duration of a project. It is important to accelerate the approvals processes, by, for example, identifying "projects of European importance" which can then receive special treatment, or by setting a duration limitation in the permitting process (interview Chaniotis). An example of this problem is the France-Spain Interconnector which has been delayed over 20 years by objections to its development. Finally a political decision has been made that the whole 60 km HVDC circuit will be underground, even though this increases the cost significantly. Underground transmission can be as much as ten times more expensive than overhead transmission, though this depends upon the individual circumstance.

Financing is another barrier. TSOs can have varying difficulties with regard to their access to and their ability to raise capital, especially in what concerns the expansion of the network infrastructures (interview Chaniotis).

Another interviewee noted five areas that need to be addressed: political, economical, environmental, technical and cultural; of which technical issues are probably the easiest to deal with. All five need to be in place, but they usually get dealt with in isolation. For example, public acceptance should be dealt with as both an economic and a cultural issue. Governments favour a free market approach, expecting market signals to drive development; whereas some "state direction" is required for consistent frameworks to be developed for the free market to deploy within. Also the supply chain is fragmented and the returns on investment are not clear (interview Botting).

Some important (institutional) barriers were removed by the creation of ENTSO-E, but we still need a more fluid network that does not see the national borders. Technological barriers are offshore, where no industrial scale solutions are readily available to date (e.g. protection issues, voltage level standardisation for meshed HVDC networks). The differences in national Grid Codes represent a relevant regulatory barrier.

All connection requirements should require a good standard of practice. The wind industry has ideas for harmonised codes, but these need to be adopted by the TSOs. Also, the increased level of renewables means that conventional generation needs to be more flexible and have more advanced provisions, which have to be addressed in the Grid Codes (interview van Hulle).

The main barrier, which was referred to in the previous section, is essentially political: the delays and uncertainties in seeking approval for major infrastructure developments. The answer to this is for each country to develop transmission corridors based on agreed scenarios of possible future requirements. It is not possible to predict the future, but all TSOs should develop a long term vision to address credible development scenarios, and get governmental approval for transmission corridors. Without this level of certainty, industry will not be able to invest in the manufacturing and installation capacity needed to address the substantial growth in renewable generation (interview van der Meijden).

4.4 Potential indicators

In the ENTSO-E TYNDP (ENTSO-E 2010a) grid developments are categorised into three groupings: to improve the security of supply; to facilitate the integrated energy market; and to integrate renewable generation. This breakdown can be expressed as a capital cost or as circuit km built or refurbished. However, these categories overlap and investment that is motivated primarily by security of supply or market integration can also facilitate the connection of renewable generation. Other than this subjective approach, there seems to be no simple way to quantify with a single-dimension indicator the network developments that are specifically addressing renewable integration (interview Chaniotis).

Another view is that results depend on what you are trying to measure – you tend to get what it is you are measuring. Regulators have one mechanism for influencing performance – economic. We should move away from only regulatory KPIs (key performance indicators) and look for system level indicators as well, since there is more than one way to solve any problem. The approach should be to optimise transmission, distribution and demand side expenditure while delivering the required systems level architecture to enable the low carbon economy defined by EU mandate. By considering the whole system (transmission, distribution and demand side), the aim should be to reduce/save capital expenditure by improving system performance, e.g. through much greater use of intelligence in the Grid, especially at the Distribution level (interview Botting).

Defining adequate indicators for grid development is very complex and requires development of a uniform approach on, for example, a reference scenario and uniform methodologies, enabling fair comparisons between countries. The IEA Wind Task 25 looked at many different studies for increasing balancing capacity; something similar for the grid would be more difficult. The (regularly updated) TYNDP of ENTSO-E could provide reference for measuring progress in network development. The networks in different countries are in different states, and network development is a non-linear process. Studies would need to be standardised and should start with an agreed baseline scenario using an established procedure (interview van Hulle).

4.5 Scenarios for future developments

The locations where the bulk of the renewable generation will be developed are, of necessity, remote from the present grid – wind generation located offshore and wind and solar generation in North Africa – which results in some radical proposals for the way the grid is to develop and can lead to so called “supergrids”. Several ideas have been proposed and studies undertaken into various aspects of the design of the required transmission grids. One of the reports produced by the IEE OffshoreGrid project (IEE OffshoreGrid 2010a) summarises the most significant off-shore grid initiatives, which mainly address the North and/or Baltic seas. But some ideas also embrace the Mediterranean, North Africa and the Middle East.

This section considers some of these ideas, in order to give an idea of the general nature of the various proposals, which range from little more than general concepts, to detailed studies of forecast growth scenarios. The first of these is based on the most detailed network modelling since it is produced by the European transmission system operators themselves and their actual and proposed network developments.

4.5.1 ENTSO-E Ten Year Network Development Plan

The ENTSO-E TYNDP released in 2010 only considers a time horizon of 2020. Within that time frame it considers the drivers of security of supply, internal electricity market and renewables integration for the development of the European grid (see chapter 4.4). And for the planned or envisaged transmission investment projects the lengths of new or refurbished circuits are classified according to these objectives. Since any particular project can address more than one of these needs, the sum of circuit lengths in these three groupings comes to 170% of the actual circuit length involved.

So the TYNDP shows the developments that will accept the renewable generation growths envisaged in the “best estimate” scenario (UCTE 2009a) up to 2020, which is essentially: pure hydro 118 GW; wind: 194 GW; solar: 38 GW; others: 23 GW. This scenario is more or less equivalent with the “IEA Reference Scenario” shown in chapter 3.1.

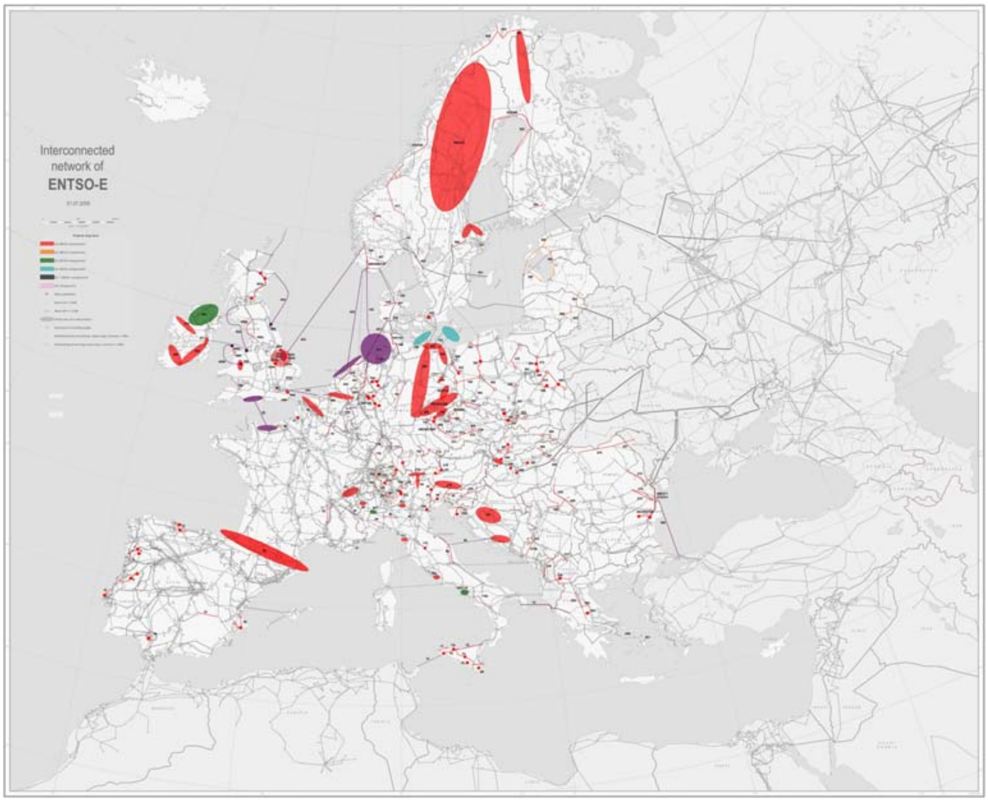

Figure 6: Projects of European significance (2015-2020) according to the ENTSO-E TYNDP
Source: (ENTSO-E 2010)

Within the TYNDP time horizon of 2020 it is premature to describe a ”supergrid“. ENTSO-E is currently looking at the possibilities for the ”supergrid“; only sketches exist at the moment, but a roadmap of studies is expected by mid 2011, with these studies being subject to “resilience testing” to check that ideas are moving in the right direction. For 2030 scenarios some form of offshore grid needs to be considered to cater for all the offshore wind generation; preliminary results based on ongoing studies within ENTSO-E are expected by the end of 2010. There are also ideas (e.g. Mediterranean Ring) to connect to solar (and wind) generation in North Africa. However solar generation is currently more expensive than wind and developments in North Africa seem not to be evolving significantly at present (interview Chaniotis).

The next edition of the TYNDP to be released in 2012 will include a top-down scenario based on the National Renewable Energy Action Plans that will provide another point of view for the attainment of the EU 2020 targets (interview Chaniotis).

4.5.2 Deutsche Energie-Agentur (dena) Grid Study

The German Energy Agency (dena) commissioned a first study into the integration of offshore and onshore wind energy into the German network (dena 2005). The study considered scenarios for the increased use of renewable energy up to 2020, analysed the effects on the transmission system, identified weak points and developed solutions. Within the framework conditions of the study, it was found that it was only possible to draft technical solutions to integrate up to about 20% of renewable generation (5% offshore wind, 7.5% onshore wind, 7.5% other renewable sources). This met the growth scenarios up to 2015, but to address the planned increase in offshore wind in northern Germany after 2015, a more extensive investigation would be required to develop viable technical solutions.

Accordingly, a “part II” study, under modified framework conditions, has been performed to examine the time period up to 2025. Aspects examined in this study include: extension of the grid including options for an overlay network; power output control of wind farms; demand side management; new storage and supervisory control of existing storage; and flexible line management. In November 2010, the final report of this study was published, which identifies the need of building up to 3 600 km of new transmission lines in Germany until 2020 to support an ambitious development of renewable energy (dena 2010). The results of this study were criticised regarding their suitability to meet long-term needs for energy systems and also with regard to the need to recognise realistic planning horizons for such large infrastructure projects (von Hirschhausen et al. 2010).

By its very nature, this study was limited to studying the German Grid and the connection of offshore wind in the Baltic and the North Sea, but the report does note that at times of low load and strong winds there will be significant impact on the reliable operation of the grids in neighbouring countries. On the other hand, coordination of the grid development at the European level might significantly reduce the overall investment needs compared to a purely national approach (European Commission 2010a).

4.5.3 TradeWind project

The TradeWind project, coordinated by the European Wind Energy Association (EWEA), was the first EU-level study to explore the benefits a European grid with better interconnections can have on the integration of a large amount of wind power. It looked ahead as far as 2030 and carried out detailed simulation of the grid under the forecast scenarios. The project identified 42 onshore interconnectors and a corresponding time schedule for upgrading that would benefit the European power system and its ability to integrate wind power. The onshore and offshore upgrades were grouped into three stages. Stage 1, the left hand map in Figure 7, consists of all currently planned upgrades plus significant interconnectors necessary to avoid any load curtailment. The right hand map shows the Stage 2 and 3 branch reinforcements on circuits with the highest sensitivities, ten in each case. See the TradeWind Project WP6 report[8] for details of the methodology for circuit selection.

[8] Available at www.trade-wind.eu.

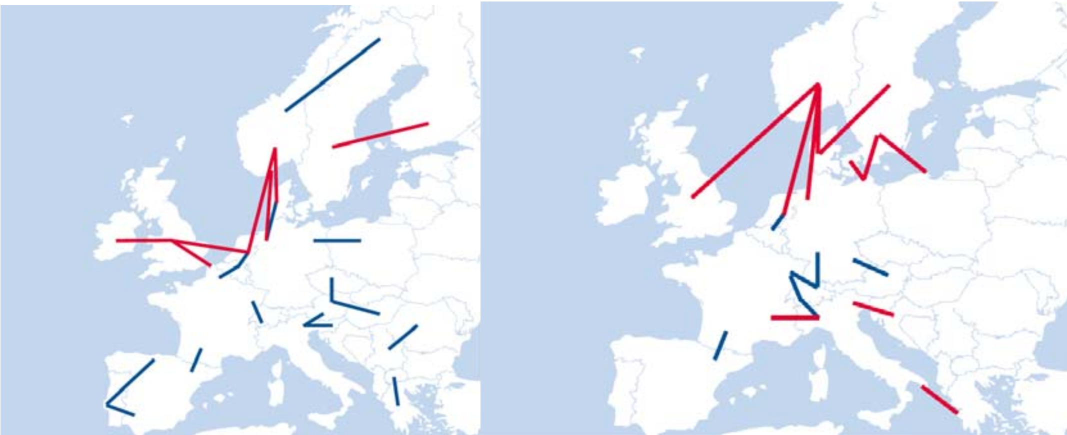

Figure 7: TradeWind Stage 1 and Stage 2 & 3 upgrades
Stage 1: left; Stage 2 & 3: right. Red: HVDC; Blue: AC
Source: (Tradewind 2009, pp.49-50)

The TradeWind project also noted that an interlinked (meshed) offshore grid could link future offshore wind farms in the North Sea and the Baltic Sea and the onshore transmission grid, and that this compares favourably (economically) to the radial connection of offshore wind to the shore; as well as offering greater flexibility for transporting offshore wind and better access to the flexible hydro capacity in Norway.

4.5.4 Intelligent Energy Europe OffshoreGrid project

OffshoreGrid is a study within the Intelligent Energy Europe (IEE) programme which is looking at technical and economic aspects of alternative offshore grid designs. Various topics are being considered: whether to cluster offshore wind farms into offshore hubs or connect directly to the shore; and whether to connect offshore wind farms to planned Interconnectors, either individually or as hubs, so establishing the beginnings of a meshed offshore network (IEE OffshoreGrid 2010b).

Part of this study (IEE OffshoreGrid 2010a) is the development of representative offshore grid scenarios for the North and Baltic seas. Four prototype designs are being developed:

1. Base case: All existing and planned interconnectors with direct wind farm connections to shore for all wind farms up to 2030.
2. Trade-driven: The base case plus several more “shore to shore” interconnectors. All wind farms are connected directly to the country of origin.
3. Wind-driven (meshed): Derived from the previous case with some of the direct interconnectors substituted by interconnectors between wind farm clusters, resulting in a thoroughly meshed grid linking wind farm clusters with each other wherever possible and considered reasonable.
4. Mixed case: A mix between the trade-driven and wind-driven scenarios, and similar to two other design approaches (Greenpeace-3E 2008) (EWEA 2009b).

This project is on-going, but preliminary results point to the integrating of wind farm hubs and interconnectors being beneficial, but requiring detailed analysis in order to evaluate any particular situation.

4.5.5 Desertec

The Desertec Foundation was established in 2009 to promote the concept of "Clean Power from Deserts" – in a European context this essentially means the Sahara, and it would need a grid network to be developed in order to transmit the power to load centres in Europe. The map below illustrates the concept. However, as noted in chapter 4.5.1 above, solar generation is currently more expensive than wind and developments in North Africa seem not to have evolved significantly at present (interview Chaniotis).

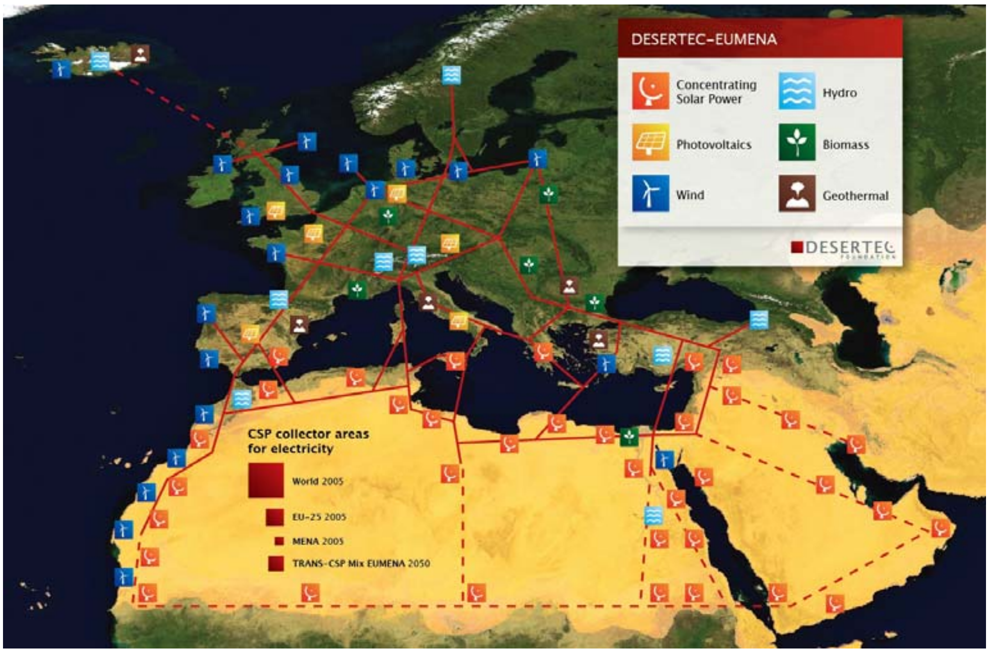

Figure 8: *Desertec grid proposal*

Source: http://www.desertec.org/downloads

4.5.6 Mainstream Renewable Power

Mainstream Renewable Power is a wind power development company founded by Dr Eddie O'Connor (who previously founded Airtricity) which promotes the idea of a European "supergrid" addressed mainly at harvesting offshore wind and simultaneously adding interconnection between countries to increase the capacity to transfer power, necessary to help compensate for the intermittency of wind. A difficulty with establishing a new grid, is avoiding investing in circuits that will remain underutilised for a considerable time. Mainstream's proposal is to establish a "supernode" in the middle of the area of sea concerned (the Dogger Bank, say, in the case of the North

Sea) to which point-to-point HVDC links can be connected, for example, to Norway, Germany and the UK.

The supernode would be an AC substation which overcomes the HVDC breaker problem and means that nearby wind farms can be connected using AC with appropriate transformation. This concept would be extended and used to develop the offshore "supergrid", as illustrated in Figure 9.

Figure 9: Offshore "supergrid" concept (Mainstream Renewable Power)
Source: http://www.mainstreamrp.com/pages/Supergrid.html

Dr O'Connor offered the following comments on "supergrid" development. He noted that existing grids were designed around generating plant for which there was at least the possibility of choosing its location (i.e. within reason, the fuel can be transported to the power station), but that a renewable friendly grid would need to transport very large quantities of electricity generated by wind or solar (from the Sahara) over very large distances. Therefore there is no way existing grids can adequately deal with the issue of incorporating adequate quantities of renewables into the grid, other than through the addition of a "supergrid".

4.6 Additional interviewee's observations

In addition to the views of interviewees that are included above, below are their observations on the development of a European Grid.

Dr Dimitrios Chaniotis, Senior Advisor System Development, ENTSO-E

> Offshore wind generation clearly has to go somewhere, and so some form of grid will be needed. In the TYNDP the barriers regarding a North Sea grid are summarised in a table (page 158). Wind is quite inflexible and providing (spinning) reserve can therefore be problematic when the wind generation is a signifi-

cant proportion of the demand, since this is typically provided by conventional plant or interconnectors. Also the market design needs to be changed to integrate wind better and accommodate its intermittences. The provision of storage would also be beneficial, and the only large scale option at the moment is pumped storage, which is possible in both Norway and the Alps, and is under consideration.

An offshore grid needs technology and a harmonised approach. For example, the development of a true HVDC network, if needed, would require a suitable HVDC breaker and although manufacturers argue that such a device is feasible, significant testing has to be performed and experience gained for a widespread use. Security of supply is a TSO's first responsibility. And the individual systems to connect the large scale offshore wind should be developed so as to facilitate the grid's development, for example by using standardised voltage levels.

Finally, it should be noted that the TYNDP is not the whole story; TSOs have internal developments in addition to those considered by ENTSO-E.

Duncan Botting, Executive Chairman and Interim CEO of the Scottish European Green Energy Centre, and Managing Director of Global Smart Transformation Limited.

The grid is the enabler for everything else, so it is also therefore the limiting factor. We have lived off the headroom from our forefathers "over engineering" over the last 40 years and the "quick wins" have all been exhausted. Ageing infrastructure combined with the changing needs being placed upon the electricity system provide an excellent opportunity to re-invent our power networks and embrace the demand side participation that has been missing from our control armoury. The nature and size of the problem will require the use of a portfolio of existing and new architectures, technologies, processes, legislation, regulation, business models and user acceptance. We should use all alternatives as appropriate, we need the whole portfolio, including, for example, HVDC Voltage Source Converter so as not to inhibit black-start recovery (cf: European blackout on 4 November 2006).

Frans van Hulle, External Technical Consultant to EWEA, Technical-scientific coordinator of the Tradewind project

Grid capability depends on how much and how fast the renewables, on the one hand, and the networks, on the other, are developed – offshore is of particular importance. The governance of the development of the generation and the development of the grid are independent processes.

Currently the grid accepts about a 5% penetration of wind across Europe – there are bottlenecks, but the TSOs are learning how to handle the variability of wind, and forecasting is making progress which helps the integration. Studies carried out at country and European level indicate where the bottlenecks are, but these mainly relate to transmission – distribution studies are not in the public domain.

The International Energy Agency (IEA) Wind Task 25 phase 1 final report is a summary of case studies addressing concerns about the impact of wind power's variability and uncertainty on power system reliability and costs (IEA 2009a). Phase 2 is ongoing, analysing and further developing methodologies.

There are major challenges to further enhancements of the grid: the building of specific/new lines; should offshore wind be connected radially or is there a need and/or a case for a meshed network, combining the functions of wind power connection on the one hand and electricity trade between markets on the other.

There are also challenges to the operation of the grid: this should be more flexible and should support more efficient unit commitment and balancing in the power market.

The need for an HVDC "supergrid" as a silver bullet for the provision of network capacity for the foreseen amount of renewables has not yet been clearly established by detailed analysis. Preliminary studies have shown that offshore a VSC HVDC grid would combine better trade with more sustainable energy, and it would have to be a European project. The Intelligent Energy Europe (IEE) OffshoreGrid study has looked at alternative offshore grid design scenarios. Onshore there have not been studies to justify the need for a "supergrid" overlay, this needs more research.

There seems to be much "hype" around smart grids, but logically what is needed is more flexibility in the system to deal with the additional variability brought about by variable renewables, for example more flexibility from conventional generation and more demand response. Since the grid transports both energy and information it will be a natural progression and the TSOs are "smart" enough to do this.

There should be more effort at the distribution level and more studies on how to reinforce the existing grid – the TSOs will make the decision on how this is done. The grid is highly meshed in Europe, but because of local limited line capacity there are congestions. An overlay grid seems a good idea, but where should it be? As yet a business case has not been made for this.

The "Twenties" project (recently launched by the EU and being coordinated by Red Electrica) will trial new technologies to facilitate the integration of wind power into the Grid.

Mart van der Meijden, Manager Innovation, TenneT TSO BV.

TenneT has published in its "Vision2030" document (Tennet 2008) how the Dutch grid could respond to four growth scenarios (Green Revolution; Sustainable Transition; New Strongholds and Money Rules). These scenarios have been developed to reflect variation on two dimensions: environmental (from focus on renewables to focus on fossil fuels) and the market (from protectionism/regulated to free market). By superimposing the network developments required to meet these scenarios, development corridors can be identified. These corridors are submitted to the Ministry of Economic Affairs and incorporated in the Electricity Supply Structure Plan (currently SEVIII).

There is no clear need for an HVDC ”supergrid“ or even for reinforcing and extending using conventional technologies. The potential for development should be established using existing and new transmission corridors, and then, as the requirement becomes clear, building or uprating the necessary circuits using old or new technology as appropriate at the time – HVDC can come later, when needed. It would be not wise to invest in the speculative building a “supergrid”; what should be done is to invest in acquiring/developing transmission corridors, which can be done for a fraction of the cost, and then the actual grid will be constructed as and when the need materialises.

5 Increased flexibility of conventional plants

5.1 Starting point and major challenges

The installed capacity of power plants in operation in 2009 within the EEA member countries totalled nearly 900 GW. About two thirds of the installed capacity are thermal power plants fired with fossil or nuclear fuels (Platts 2009).

Figure 10 gives an overview of the power plants operating, under construction or planned in EEA member countries as of 2009. The structure of the fuel mix of power plants installed changes from coal and nuclear, mainly built between 1970 and 1990, to gas and renewable energies in the recent years. The fuel switch from coal to gas is first of all triggered by international efforts to reduce CO_2 emissions and the introduction of the European CO_2 Emissions Trading Scheme (ETS) in 2005 (Möst, Perlwitz 2009). It is also due to shorter construction times and lower investment costs (Möst, Fichtner 2010), which are favourable in the competitive environment of liberalised electricity markets. The decisions on a phase-out of or a halt on new investments in nuclear capacities in some EEA countries (e.g. Germany, Belgium, Spain, the Netherlands, Sweden) reduced the installation of new nuclear power capacities since 1990 (Rosen 2008, p. 17).

The operational flexibility of thermal power plants can be determined using start-up and shut-down time, minimum load factor, maximum load change ratio and part load efficiency (Table 2). Generally, gas-fired power plants show higher flexibility than coal or nuclear power plants and therefore the flexibility of thermal power plants increases with the share of gas-fired power plants.

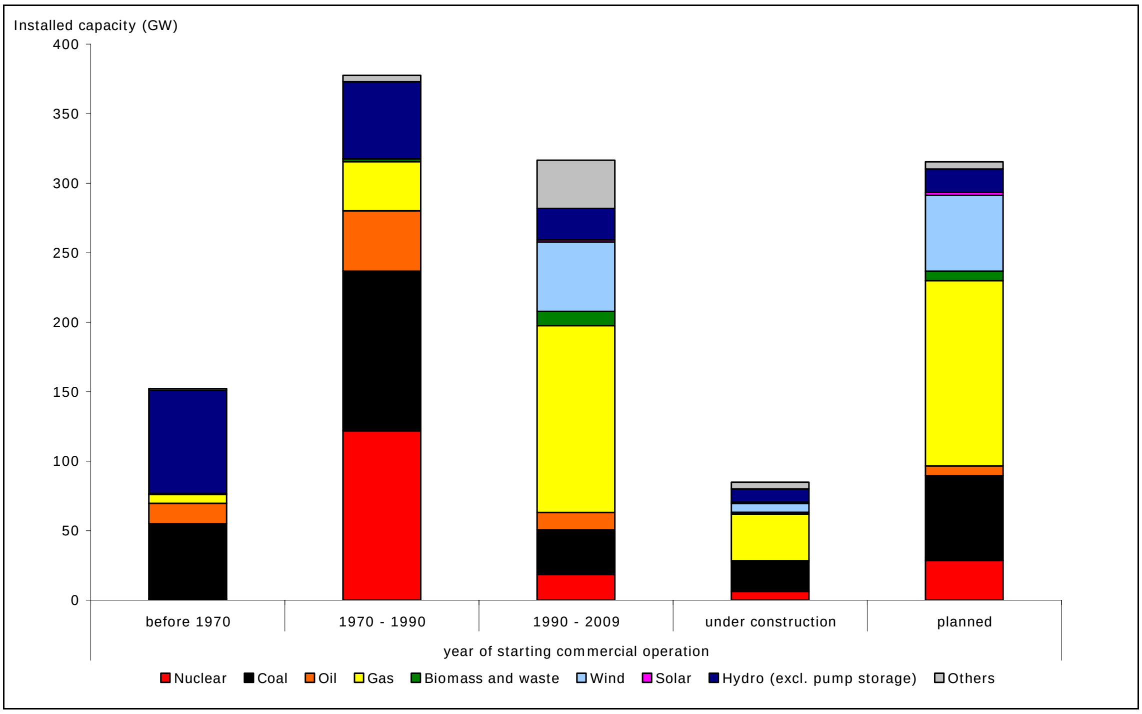

Figure 10: Installed capacities of power plants operating, under construction or planned in EEA member countries in 2009

Source: (Platts 2009, own illustration)

Specific data concerning the flexibility of biomass plants is not available in literature yet. In general, the flexibility of plants using solid biomass (wood, wood chips, waste wood) can be assumed according to coal-fired power plants. Biogas and plant oil is mainly fired in internal combustion engines with a short start-up time and a high load change ratio. The minimum load factor is about 50 % and the part load efficiency lies between 10 % and 20 % (Meixner, Stein 2002).

Table 2: Typical technical parameters influencing the flexibility of thermal power plants

	Start-up time	Minimum load factor	Load change ratio	Part load efficiency loss
Nuclear power plants	6 h – 50 h	30 % – 50 %	5 – 10 %/min	5 %
Coal-fired power plants	2 h – 5 h	40 % – 60 %	2 – 6 %/min	5 % – 10 %
Gas-fired power plants (steam cycle)	2 h – 5 h	20 % – 30 %	4 – 10 %/min	10 %
Gas turbines	< 0,25 h	20 % – 50 %	10 – 25 %/min	20 %

Source: (DEWI et al. 2005, p. 280; Rosen 2008, p. 56f)

The total installed capacity of gas-fired power plants in operation in 2009 is 180 GW and will nearly double to 340 GW if all plants under construction or planned are realised. This increase of gas-fired power plants could then keep up with the assumed increase of installed wind capacity in the scenarios shown in Figure 11. In general, the installed capacity of gas-fired plants is expected to remain larger or equal to the capacity of wind power plants if decommissioned gas plants are replaced as well.

A challenge for all fossil and nuclear power plants is the expected decrease in their full-load hours due to the growing shares of renewable energy and their priority access and priority dispatch. This particularly impacts power plants with high investment costs, like coal and nuclear power plants, which are currently run as base load or medium load plants. Gas-fired plants will be less affected by this challenge due to the lower investment costs. Due to the high start-up flexibility of gas turbines, their full-load hours could increase in general.

5.2 Potentials and uncertainties

About 120 GW of new fossil fuel plants are currently under construction or with confirmed construction decision[9] in the EU27. Most of them are gas-fired plants (73 GW gas turbine combined cycle, 12 GW small-scale gas and oil plants). Besides gas-fired power plants, coal-fired and even nuclear power plants could also be operated in a more flexible mode. There are confirmed decisions for some 27 GW of coal and lignite plants (EURELECTRIC 2009, p. 56). Countries with coal as domestic fuel resources, like Poland and Germany for example, are expected to continue the operation of coal-fired power plants (interview Karl).

Relevant factors for investment decisions in thermal power plants are the plant-specific investment costs and the expected development of fuel costs. For fossil fuel-fired power plants, the allocated amount of CO_2 emissions, the efficiency of the plant in respect of the CO_2 emission factor and the expected development of CO_2 costs under the ETS are further important factors. While for gas-fired power plants the fuel price risk is the main uncertainty, the CO_2 price risk is vital for coal-fired power plants.

Some EEA member countries continue investments in nuclear power plants, such as France, Finland and Great Britain (see Figure 10) (interview Karl). The technical flexibility of nuclear power plants in operation is generally comparable to other thermal power plants; however it has rarely been used so far. For example, the German nuclear power plants Neckarwestheim 1 and Philippsburg 1 were operated in 2009 in a load-following mode (atw - International Journal for Nuclear Power 2010). The start-up flexibility after a nuclear plant has been shut down is quite low compared to other technologies (Table 2). In countries or regions dominated by nuclear power plants, these power plants are necessarily already being operated in a load-following mode. In

[9] Compared to power plants with status “planned” in the Platts database, the construction of these plants is more certain.

France for example, specifically designed mid-load nuclear power plants are in operation (interview Möst).

However, with the further increase of renewable energy and the priority access they have to the electricity grids, the expected reduction of the full-load hours for thermal power plants is becoming an increasingly relevant factor (interview Möst). This might lead to rising electricity prices, because these plants have to recover their investment costs with a decreasing amount of electricity generated (interview Karl). The projected prices of electricity in the EU27 increase on average from 95 €/MWh in 2010 to 145 €/MWh in 2030, both in the EU 2009 Baseline scenario[10] and the EU 2009 Reference scenario[11] (European Commission 2010c, p. 30 and 45).

5.3 Barriers and requirements for action

Part of today's barriers to the installation of new flexible plant capacities can be found in the political framework conditions: The proposed extension of the lifetime of nuclear power plants in Germany, for example, reduces the profitability of gas-fired power plants and will probably lead to a reduction of investments in this technology.

The uncertainty about costs of CO_2 emission allowances is also due to the framework conditions of the national allocation plans of the ETS and the timeframe of the allocation period. An extension of the allocation period would increase the planning security for power companies and could lead to more investment decisions (interview Möst). Depending on the expected number of CO_2 allowances required and their expected costs, investments in more flexible gas and (partly) coal-fired power plants could be preferred under these framework conditions.

The more flexible operation of fossil and nuclear power plants on the other side is limited by start-up costs and additional cost for maintenance of plants with high load change and operation cycles.

Although the electricity market should in theory be able to reflect a more flexible operation of thermal power plants in its price formation, the installation of a capacity market could be an additional option to support investments in new and more flexible plant capacities.

5.4 Contribution to the potential indicators

5.4.1 Provision of balancing power

Thermal power plants can provide spinning reserve for primary and secondary control as well as minute reserve. They are currently the most important sources of balancing power in the electricity system.

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[10] The Baseline scenario determines the development of the EU energy system under current trends and policies.

[11] The Reference scenario includes additional policies and national targets under the Renewable Energy Directive 2009/28/EC and Decision No. 406/2009/EC on effort sharing.

The level of balancing power from thermal power plants in future situations with large shares of non-dispatchable (renewable) generation can be calculated based on two parameters. The first one is the capacity of operating dispatchable plants, which can be derived from the difference of the total load and the non-dispatchable electricity generation. The resulting demand for dispatchable capacity can be calculated as an arithmetic mean or annual minimum capacity.

The second parameter is a technology-specific factor for providing spinning reserve, for example by throttling capacity. These factors can be derived from a technical literature review.

As a final step, the share of different power plant technologies within the derived dispatchable capacity has to be assumed in order to weight the technology specific factors accordingly.

5.4.2 Provision of short-term backup power

Thermal power plants can provide short-term backup power during operation. Due to their short start-up times, gas turbines and other gas-fired power plants are able to provide short-term backup power also from a shut-down plant mode.

The determination of this indicator therefore requires two steps. The first part of flexibility is calculated as a product of dispatchable capacity under operation (see above) and the technology-specific load change factor.

The second part considers the annual plant capacity of gas-fired plants, which is not in operation and ready for start-up. This capacity can be derived from the difference between installed capacity and plant capacity in operation when a factor which reflects plant outages for revisions, etc. is subtracted.

5.4.3 Provision of longer-term secured capacity

Thermal and hydro power plants are the major option for providing longer-term secured capacity for a virtually unlimited timeframe. The longer-term secured capacity can be calculated as a product of available capacity and scaling factors representing the probability of plant failure. These scaling factors are generally defined as 1 minus the probability of failure. For thermal power plants the technology-specific scaling factors lie between 96 % to 98,5 % (DEWI et al. 2005, p. 239). The scaling factor for run-of-river power plants is set to 100 % in general (DEWI et al. 2005, p. 244).

If it is planned that thermal and hydro power plants will back up wind and solar energy production in times of longer intermittencies, these power plants must be able to cover the full expected load minus the secured capacity of wind and solar plants during these periods.

5.5 Scenarios for future developments

Most scenarios considered in this paper show only a limited or no further increase in total thermal plant capacity between 2010 and 2030. The total capacity of thermal plants in EU27 is therefore expected to lie between 550 GW to 700 GW in 2030, Figure 11).

Only the advanced EREC scenarios result in a significant decrease of total thermal capacity to 300 GW in 2030 (EREC, Greenpeace 2010, p. 62-64).

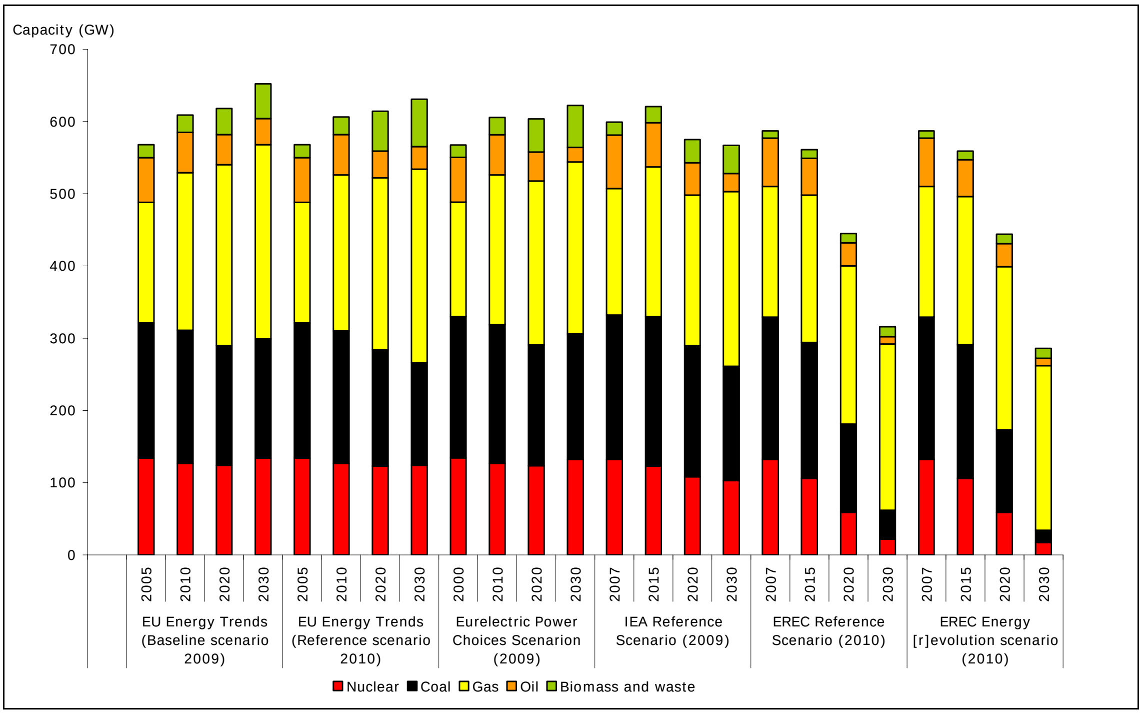

Figure 11: Projections for the development of thermal power plants in the EU27

Source: (EREC, Greenpeace 2010; EURELECTRIC 2009; European Commission 2010c; IEA 2009b)

The interaction of the decreasing flexibility of thermal power plants in operation and the increasing stand-by flexibility of gas-fired plants is difficult to assess in detail with a static approach. In order to identify the temporary demand of high flexibility in the case of high volatility from wind and solar power, a dynamic approach to modelling the energy system would have to be used.

6 Increased flexibility of renewable plants and Distributed Generation

6.1 Starting point and major challenges

Renewables and small-scale CHP plants have generally not been operated according to system requirements up to now, but rather under support mechanisms with priority dispatch and geared towards local heat demand in the case of CHP. However, these plants can also contribute to fulfilling the demand for flexibility that increases due to variable and intermittent renewable energy production. Exploiting this potential may also become attractive for the plant operators if it allows them to sell an additional product, especially once plants drop out of their respective support mechanism.

6.1.1 Distributed generation

For the purpose of this report, power plants with an installed electrical capacity of up to 10 MW are regarded as distributed generation. Besides small- and medium-scale hydro plants, small wind power plants[12] and solar photovoltaic installations, there are also several thermal conversion technologies which can be regarded as distributed generation, such as micro gas turbines, internal combustion engines, micro steam turbines and Stirling engines.

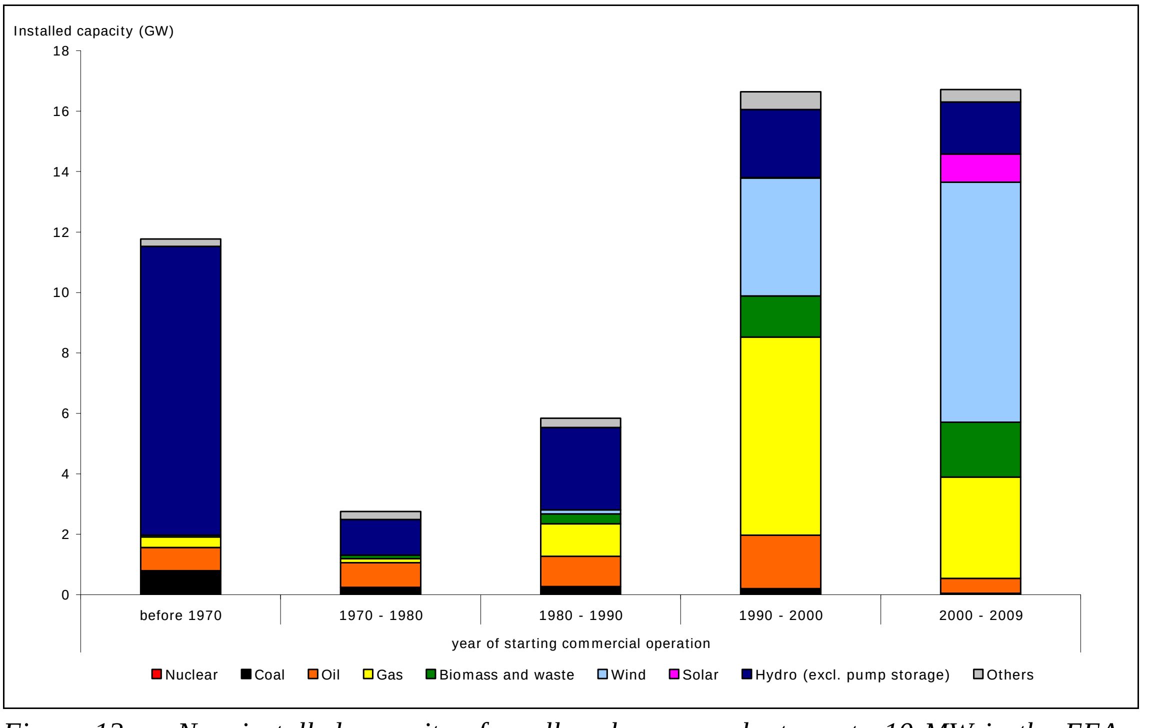

Figure 12: New installed capacity of small-scale power plants up to 10 MW in the EEA member countries until 2009.

Source: (Platts 2009 , own illustration)

In the Platts World Electric Power Plants Database 2009 there are 28 000 small-scale units operated by companies listed within the EEA member countries. Their total electrical capacity is about 60 GW (7 % of total installed capacity) (Platts 2009). The main fuel types used in small-scale power plants under operation and installed before 1990 are hydro, light oil and natural gas. Since 1990 the installed capacity of small-scale power plants increased significantly, especially for natural gas as well as biomass, wind and solar power as renewable energy sources (figure 12). Small-scale CHP and solar photovoltaic installations from private households are not included in the Platts Database

[12] About 5 500 wind power plants of up to 10 MW which have an installed capacity of 12 GW and 1 500 wind power plants of more than 10 MW (40 GW total capacity) were under operation in EEA member countries in 2009 (Platts 2009).

6.1.2 Intermittent renewable plants

Due to their dependency on weather conditions, wind and solar power plants have less flexibility options than thermal power plants. If running, wind and solar power can supply downward flexibility to, for example, compensate forecast errors. Although as a consequence renewable energy is wasted, this can be used as a last resort if no other flexibility can be activated at reasonable cost. In Spain for example, where the installed wind capacity has grown rapidly from less than 1 GW in 1996 to over 16 GW in 2009[13], a centralised Control Centre of Renewable Energies (CECRE) has been implemented to curtail wind power in real time if necessary (Ofgem 2010, p. 39). Since 2008, wind power has already had to be curtailed by the system operator for some hours, when low demand and high wind power generation co-occurred (de la Fuente 2010).

Besides downward flexibility, wind and solar power plants may technically provide voltage and frequency control as ancillary services. New generations of intelligent inverters may provide frequency-dependent control of active power and static or dynamic grid support based on reactive power. Furthermore, it is possible to avoid grid overload via power limitation as well as immediate disconnections in the case of short disruption of grid voltage (Low Voltage Ride Through) (SMA 2009; SMA 2010).

With an increasing share of wind and solar power, these plant types will have to participate more and more in providing ancillary services. Current revisions of legislation on national and European levels are already addressing the issue of primary control through wind parks. In the recent version of the German Ordinance on System Services by Wind Energy Plants (“Systemdienstleistungsverordnung“) and the medium-voltage directive all new wind plants connected to the medium and high voltage network have to be able to reduce active power within one minute and to supply reactive power.

6.2 Potentials and uncertainties

6.2.1 Distributed generation

Besides the technology-specific investment costs, the expected development of electricity and fuel prices are relevant factors for investment decisions for small-scale thermal power plants. For CHP plants, the development of the heat demand, the expected development of revenues for heat delivered and the public support for CHP are additional influence factors on investment decisions. Gas-fired engines (mostly internal combustion) are expected to be the main technology path for small-scale CHP. The development of small-scale CHP plants is also competing in the heat market with the development of larger district heating networks (interview Erge).

The share of electricity produced in CHP plants in the EU-27 was about 11 % in 2008. Denmark shows the highest share of CHP (46 %), followed by Finland, Latvia and the

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13 There are plans to reach 20 GW by 2010.

Netherlands (all about 35%) (Eurostat 2010). The success of CHP in Denmark is based on long-term planning of the development of the heat sector and on sufficient heat and gas storage capacities (interview Erge). Small-scale CHP plants, e.g. in households, currently play only a minor role in CHP electricity generation (Obersteiner et al. 2008, p. 15). The overall CHP potential can be assumed with 25 % of total electricity generation, although some EEA member countries have already achieved higher rates (interview Erge).

For small-scale RES plants, the further development still depends strongly on public support schemes like feed-in tariffs and priority access to the grid, especially due to higher investment costs of small-scale plants.

With the share of small-scale thermal plants increasing, the potential of flexibility provided by them rises correspondingly. The technical and legal inclusion of small-scale thermal power plants into a smart grid concept is essential for the use of their flexibility potential but also constitutes one of the major challenges.

6.2.2 Intermittent renewable plants

In general, the guaranteed power from wind and solar power plants increases in absolute as well as in relative values when their installed capacity increases due to a wider geographical spread of the plants. The variability can therefore be balanced to some extent by widespread installations of wind and solar power plants. As a result, the flexibility for downward regulation, which is limited to the available and assured power of wind and solar power plants, increases as well. Since it entails wasting renewable energy, downward regulation should be used only in situations where no other suitable option is available at reasonable cost.

6.3 Barriers and requirements for action

Both for intermittent and non-intermittent plants that are not competitive but depend on a support scheme, there is a potential tension between two different kinds of market integration: market integration in terms of reacting to market signals and market integration in terms of depending in market prices without further support. On the one hand, full market integration in terms of depending on market prices would incentivise them to react flexibly to system requirements, but would undermine their economics. On the other hand, keeping these plants in niches to shield them from market risk and support their further deployment inhibits market integration in terms of reacting to market signals. Therefore, a key challenge is to develop existing support mechanisms so as to combine the two objectives: a stable investment environment and incentives for reacting to market signals.

Market integration of renewable and distributed power also requires a proper functioning of the electricity market. More specifically, the design of electricity market should enable these plants to participate in both electricity and ancillary service markets, and provide the electricity products they can generate. Moreover, market design should ensure that RES-E generators should take on balancing responsibilities, but not unduly penalise them for their generation characteristics, especially in the case of variable and intermittent generation. For example, variable generators highly benefit from the possibility of correcting their forecasts close to real time. This requires intraday trading possibilities and short gate closure times.

6.3.1 Distributed generation

The asynchronous demand for electricity and heat is the main barrier to the use of flexibility from CHP plants. Therefore, sufficient storage capacities for heat are essential to extend the flexibility on the heat side of CHP and thus offer a higher degree of freedom for the electricity generation side. Similarly, gas-fired plants with continuous gas supply from biological processes need sufficient gas storage capacities in order to extend the flexibility and duration of full-load plant operation (interview Erge).

Due to guaranteed feed-in tariffs, biomass-fired plants show typically a plant design optimised for continuous operation (approx. 7 500 h/a). To increase their flexibility, an extension of the installed electrical plant capacity could be necessary to compensate downward regulation with increased electricity and heat generation later on. In this way, these plants could be integrated into market conditions in which providing flexibility is a relevant factor for profitability.

Concerning barriers to CHP in general, the maximum duration of feed-in or similar support schemes for CHP in some countries limits investments in new CHP plants as well as the long-term operation of existing plants after support has ceased. The extension of the duration of support, possibly at reduced levels, could be an option for stimulating higher shares of CHP generation.

The decreasing heat demand in buildings due to improvements in their thermal insulation, large investments for the set-up of new heat networks and the difficult competitive situation of district heating in the heat market are other general barriers to the development of CHP. Compulsory connection of heat consumers to heat networks is one of the measures which can support the expansion of distributed generation based on CHP. In Germany, for example, this option is regulated in §16 of the German Renewable Energies Heat Act[14] (Erneuerbare-Energien-Wärmegesetz – EEWärmeG) of 2008 (Federal Law Gazette 2008 No.36), but it is only rarely used so far. This act incorporates partially Directive 2009/28/EC on the promotion of the use of energy from renewable sources, where the “Member States shall permit those minimum levels to be fulfilled, inter alia, through district heating and cooling produced using a significant proportion of renewable energy sources” (see Article 14 of Directive 2009/28/EC).

Integrating small-scale plants into the market is not just a matter of market and support scheme design, but also requires building up a technical infrastructure to be able to control these plants according to system needs. For small-scale plants, market integration is a realistic option only if automated processes are available for that purpose.

[14] The municipalities and local authority associations can make use of a provision under Land law authorising them to establish compulsory connection and use regarding a public local or district heating supply grid, also for the purpose of climate protection and resource conservation.

6.3.2 Intermittent renewable plants

The main barrier to using flexibility from wind and solar power plants is the fact that any downward flexibility is associated with wasting renewable energy. This barrier might become less relevant once renewable energy has reached very high overall shares in electricity production and causes situations of local overproduction. In these cases the installation of additional wind power with the option of using downward regulation could be a better option than a further extension of the network to accommodate additional wind or solar peak power, which will be only produced for a very few hours per year. However, if there are any other flexibility options available, wind and solar generation should only be curtailed in extreme situations.

6.4 Contributions to the potential indicators

6.4.1 Provision of balancing power

6.4.1.1 Distributed generation

Small-scale thermal power plants can provide balancing power for primary and secondary control as well as minute reserve during plant operation. In contrast to large-scale thermal power plants, small-scale power plants based on internal combustion can also provide balancing power as standing reserve due to very short start-up times.

For non-CHP plants, the total installed capacity can be used as balancing power. On the other hand, the flexibility of CHP plants is restricted by the need to produce heat, unless a suitable capacity of heat storage is provided for.

6.4.1.2 Intermittent renewable energy

Other than non-intermittent renewable energy (e.g. biomass), which can provide balancing power both as “standing” and “spinning” reserve, intermitted renewable energy plants can only provide balancing power as “spinning” reserve while they are under operation. To determine their contribution to this indicator, their plant capacity under operation and the corresponding technology-specific scaling factors have to be taken into account.

6.4.2 Provision of short-term backup power

6.4.2.1 Distributed generation

Small-scale thermal power plants can provide short-term backup power both as spinning and standing reserve. The heat demand profile and the corresponding heat storage capacities restrict this kind of flexibility, as discussed in section 6.4.1.1. The volume of available short-term backup power can be determined as described in this section.

6.4.2.2 Intermittent renewable energy

The implementation of on-site storage capacity is an option for some intermitted renewable energy plants to provide short-term backup power. This is possible for concentrating solar thermal power plants, as can be seen from the Andasol power plant in

Spain (Solar Millennium 2009). If no on-site storage is possible, intermittent renewable energy plants cannot provide short-term backup power.

6.4.3 Provision of longer-term secured capacity

6.4.3.1 Distributed generation

Due to the heat demand to be covered by CHP plants and the continuous fuel supply for many biogas plants, these plants are designed for continuous operation and thus cannot provide longer-term secured capacity in the case of wind or solar energy intermittencies. However, non-CHP plants fired with natural gas, light oil, plant oil or solid biomass might be able to provide some level of longer-term secured capacity.

6.4.3.2 Intermittent renewable energy

Intermittent renewable energy power plants cannot provide longer-term secured capacity.

6.5 Scenarios for future developments

6.5.1 Distributed generation

EU member states have agreed to increase the share of CHP by activating their CHP potentials. This will also lead to an increase of capacity from small-scale CHP plants, and will thus extend their potential to provide flexibility. Whether or not these plants will be equipped with heat storage will depend on the local framework conditions. Heat storage systems might also be promoted by the public support schemes for CHP.

6.5.2 Intermittent renewable energy

The share of intermitted renewable energy plants will rise considerably within the next decades. To the limited extent described above they will therefore also be able to provide more (downward) flexibility in the future.

7 Expansion of energy storage

7.1 Starting point and major challenges

Electricity storage can help to match electricity generation and demand and most electricity systems dispose some storage capacity. The main purpose of storage has been to deal with electricity generated by inflexible base-load plants, such as nuclear. The only large-scale technology that has been available at acceptable costs is pumped storage.

As a consequence of increasing generation from renewables, the demand for storage will increase and storage can be expected to provide a broader range of services. Instead of balancing generation from inflexible plants, storage becomes more relevant for balancing generation that is intermittent and not entirely predictable. A recent study in the US has shown that, depending on the framework conditions, adding storage capacity to a grid with high RES penetration can be two to three times as effective as adding a combustion turbine as peak generator (California Energy Commission 2010).

Further potential drivers for storage growth include increasing demands for better power quality in the “digital society”, demand for network investments that may be replaced or deferred by storage as well as the development of microgrids that require local back-up capacity.

The following two scenarios illustrate the increasing demand for storage due to RES growth. Whether and how this storage capacity can actually develop in liberalised power markets is not yet clear.

The IEA (2009a) presents a scenario in which the storage capacity in the Western European Union increases from 36.3 GW in 2007 (considering pumped-storage only) to up to 90 GW in 2050. This is based on the assumption that the share of wind and PV generation rises from just under 10 % in 2010 to 30 % in 2050. The study focuses on short-term fluctuations and frequency control, which arguably represents only one part of potential applications for storage. It argues that these variations can be levelled out across Europe, so that storage requirements can be reduced. Nevertheless, the report illustrates how RES growth triggers increasing demand for storage.

Similarly, for Germany there are scenarios in which intermittent renewables are able to expand their share in net power generation more than eightfold by 2050 (Öko-Institut e.V., Prognos 2009). As a consequence, storage capacity in Germany is expected to triple from 6.7 GW today to 20.4 GW by 2050.

Importantly, it is not sufficient to examine the future need for energy storage in terms of overall capacity only. Although such figures can indicate the increasing demand for storage, they do not capture the demand for different storage services. A distinction needs to be drawn between short-term and long-term storage (see chapter 3). The mode of operation depends on the storage technology at hand and also influences the economics of storage plants.

Short-term storage can help to compensate for short-term fluctuations that have not been forecasted, it can provide voltage support and balancing power. This requires quick response times, but can be based on rather small storage volumes that can generate power only for limited time periods.

More long-term storage ranging from hours to weeks and even seasonal storage is needed to manage the intermittency of renewables, i.e. store energy when RES generation exceeds demand and provide back-up power for periods with low RES generation. In this case, storage helps to decouple generation and consumption. This type of storage presupposes larger storage volumes so that longer periods can be bridged. Only this kind of storage can significantly contribute to replacing conventional generation capacity by intermittent renewables.

The following figure provides an overview of different storage applications. It also shows that managing renewables in the power system requires the whole range of storage capabilities.

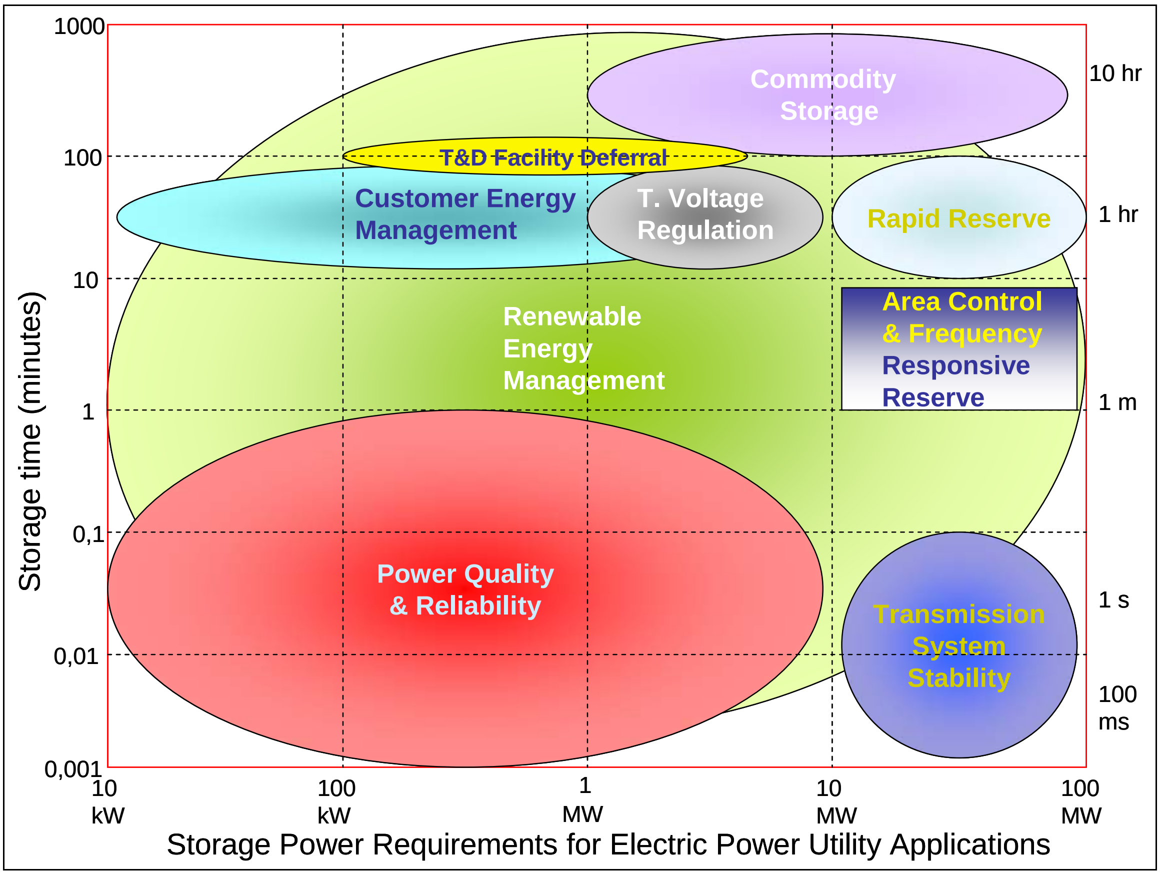

Figure 13: Overview of electricity storage applications.

Source: Electricity Storage Association (www.electricitystorage.org/ESA/applications), based on Butler et al. (2002)

7.2 Potentials and uncertainties

In comparison with other flexibility options discussed in this report storage can have a number of advantages. As compared to most conventional plants (see chapter 5), storage typically provides standing rather than spinning reserve. Therefore, reserve can be made available without generating electricity all the time. In systems with a high share of renewables that increases both reserve requirements and periods with a generation surplus from renewables standing reserve reduces the conflict between conventional and renewable generation and enables the system to accommodate more generation from RES plants (Black, Strbac 2006).

While some generation plants such as OCGT can also provide standing reserve, they can only provide flexibility in that they increase or decrease their output depending on RES generation, but cannot store RES generation that exceeds demand.

In comparison with load management options that can provide demand-side flexibility (see chapter 8), stand-alone storage plants generally can provide a higher storage volume and can store energy for longer time periods. A related advantage is that large-scale storage facilities are easier to control than decentralised flexibility options and are less dependent on the information and communication technology (ICT) infrastructure required to exploit small-scale flexibility.

As with other flexibility options, there is a potential conflict between cost and CO_2 reductions that can result from storage. Storage can help to increase the efficiency of the operation of fossil-fuel plants, thereby reducing both costs and CO_2 emissions. However, if the flexibility provided by storage plants flattens the load curve that needs to be generated by conventional plants, this increases base load generation at the expense of peak load plants. As a consequence, in many systems coal generation will increase, while gas-fired generation will decrease (e.g. Ummels et al. 2008). This can lead to a net CO_2 increase due to storage, at least in the short-term when storage is introduced in current systems. However, this problem will become less severe, the more significant the share of RES becomes.

Storage includes mechanical, thermal, electrical, electrochemical and chemical storage. The only option currently available at a large scale is pumped storage. In most countries, there is only limited potential for additional pumped storage capacity and often very low public acceptance. A significant potential may exist in Norway, where existing reservoir plants may be turned into pumped storage plants without building additional reservoir capacity (SRU 2010). However, using this potential for balancing renewables outside Norway requires major transmission infrastructure investments.

Besides pumped storage plants there is a broad range of alternative storage technologies available. However, most of them require further technological development or are not yet economically viable.

Compressed-air energy storage (CAES) is another mechanical storage option that has been used in two large-scale plants, one of them in Germany. Its efficiency has been low, but can be improved with so-called adiabatic storage. As with pumped storage, a major problem for this technology will be to find sites with suitable geological formations.

As for batteries, there is a broad range of different technologies. Batteries have typically very fast response times and can be used for frequency control and especially primary reserve. They are a relatively flexible investment and can be used in decentralised applications, e.g. in distribution networks. Costs are still high, but there is potential for cost reductions due to automated production of larger numbers (VDE 2008: 39). Electric vehicles represent a potential new market for battery technologies (Divja et al. 2009).

Chemical storage with hydrogen that has an energy density of about 250 times that of pumped storage represents an important option for storing large amounts of energy. In the medium to long term, hydrogen may become relevant, especially if there is no longer sufficient conventional generation capacity to meet demand when RES generation is low. However, the technology is not yet mature and suffers from low efficiencies and high costs.

A further option that has received some attention is the use of heat as a storage medium. Heat storage requires increasing electricity-based heat supply, since the heat can generally not be turned back into electricity. On the one hand using electricity for heat production is generally a very inefficient way of using the primary energy source; on the other hand heat storage is a relatively low-cost storage option (Danish Technological Institute no date).

As mentioned earlier, there are significant differences in the storage services different technologies can provide. The following figure illustrates this point: It provides an overview of different technologies, their typical generation capacities and discharge times (i.e. the storage volume to generation capacity ratio) as well as typical applications that result from these parameters. The figure shows that these technologies can typically provide discharge times of only a few hours. For longer periods, additional technologies such as hydrogen storage are needed.

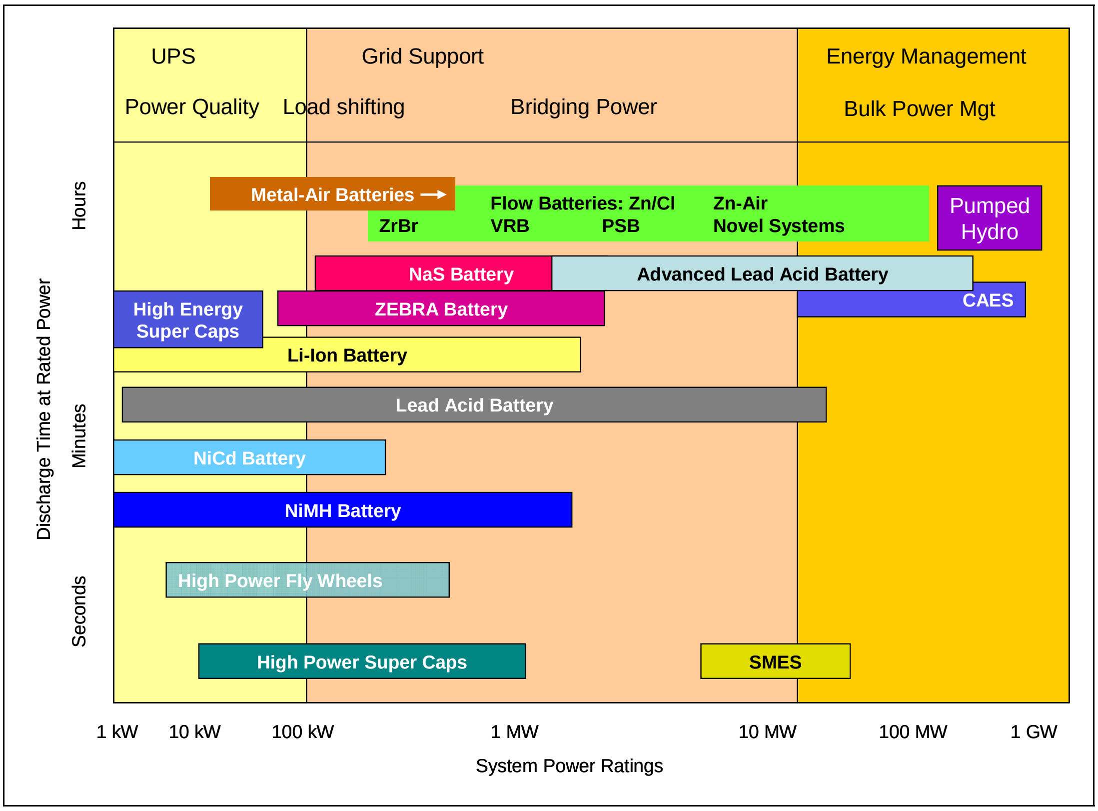

Figure 14: *Comparison of energy storage technologies*
Legend: UPS = Uninterruptible power supply; Caps = Capacitors;
CAES = Compressed Air Energy Storage; SMES = Superconducting magnetic energy storage

Source: *Based on IEA (2009a)*

7.3 Barriers and requirements for action

There is a potential mismatch between the need for expanding storage capacity to manage RES growth on the one hand and the high costs and unattractive economics of most storage technologies on the other hand. This has been confirmed in the interview with Price; BCG (2010: 12) in their recent report on storage also conclude that "*given* *the currently weak business case for storage technologies compared with other approaches to compensation, it is unlikely that investments in storage facilities will be made in the next few years.*"

From an orthodox market perspective it could be argued that the increasing demand for flexibility will be reflected in market prices and will therefore make storage economically viable and trigger efforts for cost reduction. However, there is also a general discussion on the ability of liberalised power markets to provide the required investment and innovation in power plants and networks in due time (e.g. de Vries 2004). This discussion needs to be extended to storage.

Generally, the specific market design influences the value of storage (European Parliament 2008: 41-43). The economics of storage is based on an arbitrage between low- and high-price periods. As a consequence the price spread in the market is essential. Storage plants therefore depend on high peak prices. Moreover, the spread may not be big enough without negative prices (interview Price). However, market design or even political interference may inhibit extreme prices and thus contribute to making storage uneconomical.

As for the effects of RES support mechanisms on storage, quota systems lead to a higher exposure of RES generators to the market risk as compared to feed-in systems and therefore provide in principle a higher incentive to invest in storage. However, this risky environment may also deter further investments in high-cost storage technologies by RES developers. Efforts to make feed-in schemes more flexible (e.g. the direct selling option in the German Renewable Energy Sources Act EEG) to promote market integration of renewables can also help to promote storage if RES operators rely on storage being able to take part in the market.

It has also been proposed that the provision of storage be made mandatory for RES generators (interview Price). However, there is a danger that this undermines the support mechanisms and leads to an inefficient over-capacity of decentralised storage solutions that neglects the levelling out that typically occurs between different intermittent generators.

Alternatively, since demand for storage increases because renewables are pushed into the market with the help of various support mechanisms, the question arises as to whether these support mechanisms should be explicitly extended to enable storage technologies to exploit similar learning curves.

In terms of network access, storage technologies that are not only used locally generally face the problem that they use the network twice for every kWh stored: once when they buy electricity and once when they sell it. Even in systems where feeding electricity into the grid is free of charge (i.e. the "g component" is zero) this increases the costs of electricity from storage plants, because network charges are to be paid both by the storage operator and the end consumer. On the one hand, this reflects the additional network usage due to storage. On the other hand this can represent a significant extra cost for storage plants. In Germany, § 118 of the German Energy Industry Act

(EnWG) stipulates that new pumped storage plants that come into operation between 2008 and 2019 will be exempted from network charges for ten years.

The economics of storage can be improved if it can participate both in the power market and provide network services. However, providing system services for network operators or replacing network investments with the help of storage can be inhibited by network regulation. If the regulator does not accept the costs that result for the network operator, it is likely to prevent network companies from relying on such solutions as an alternative to more conventional network upgrades. Moreover, unbundling rules prevents network companies from operating energy storage plants themselves; and it is therefore worth considering whether storage used to provide network services can be exempted from unbundling rules.

7.4 Contribution to the potential indicators

Storage can contribute significantly to the flexibility needed for the integration of variable and intermittent renewable energy. In terms of providing balancing power and short-term backup power, start-up times and the ability of different storage technologies to adapt their output are important parameters.

However, as was mentioned above, simply adding up the capacity of different storage technologies only provides a very rough indicator of the contribution storage can make to facilitating RES integration. Instead of simply examining the overall capacity, it is important to understand the storage services that different options can provide.

Especially in terms of providing longer-term secured capacity another key indicator besides capacity that needs to be considered is the available storage volume. A large generation capacity in storage plants is less valuable if not combined with an appropriate storage volume. The storage volumes determine the extent to which periods of low RES generation can be bridged by means of energy storage.

7.5 Scenarios for future developments

Despite ongoing RES growth, the current system generally seems to be able to manage intermittent generation without additional storage capacity for the time being. For example, a study on the flexibility in the Dutch and Northwest European power market in 2020 comes to the conclusion that additional storage capacity will have a very low load factor (Frontier Economics 2010). In the German scenario mentioned earlier, RES targets can be accommodated without additional storage capacity roughly until 2020.

However, it can be expected that this starts changing afterwards, as also shown in the German study. Storage demand can be expected to make a step change when RES generation more often becomes equal to or even exceeds demand. This development will be reinforced if RES generation increasingly replaces conventional capacity that can then no longer be used to provide back up.

In the near future, storage will be mainly used to cover short-term system requirements, such as system balancing. In the longer term, when RES increases further and the residual load will more often become negative, there will be increasing demand for storing energy over longer time periods (interview Price). This type of flexibility can only be provided by storage, unless significant non-intermittent capacity is kept in stand-by.

This has important repercussions on the type of storage technologies that are required. Different storage will be used to cover different time periods for which energy needs to be stored. Storage options such as hydrogen that have a high energy density and corresponding high storage volumes might become more relevant. The development of corresponding storage options may lag behind the demand for them.

Both in economic and environmental terms, the value of storage can be expected to increase significantly in the longer term once its main function is to store electricity to replace generation from fossil-fuel plants rather than mainly providing short-term flexibility. Instead of keeping conventional power plants in standby so that they can start generating once output from intermittent sources is low, energy can be stored in periods with excessive wind generation to be used when generation falls below demand. In this case, storage directly replaces generation from fossil fuels and helps to increase the amount of renewable generation that can be used in the system. In this case, the economics of storage directly depend on prices for fossil fuel and CO_2 certificates.

8 Expansion of demand-side flexibility

Based on the increasing penetration of Smart Meters in many European countries and the opportunities offered by modern information and communication technologies (ICT), many experts expect that a significant share of current final electricity consumption could become flexible in the future. The original idea behind Demand Response strategies is that parts of the electricity consumption could be shifted from times of system load peaks to times of low demand.[15] In future energy systems with a high penetration of wind and solar, Demand Response could help to relieve the stress on electricity systems in the case of variations and intermittencies in renewable electricity production rather than just cutting peaks. Thus Demand Response could help to integrate more renewable energy into the electricity system than in a case with only inflexible load. New applications of electricity such as e-mobility could further increase the potential for demand response. This section explores the conditions for realising these visions.

[15] It should be noted that the terms Demand Response and Demand Side Management are often used in a wider sense for all measures which aim at influencing the level and shape of the demand curve. Most prominently, this also includes measures promoting demand-side energy efficiency. In this paper we use the narrow definition of Demand Response as given above.

8.1 Starting point and major challenges

In some sectors of electricity consumption, Demand Response has already been used for decades. This mostly relates to some industrial and commercial applications of electricity for which curtailable and interruptible supply contracts have been agreed with the consumers (direct load control). These contracts define certain compensations in the case that the supplier or network operator decides to restrict electricity supply. These arrangements help the energy system to cope with extreme peak load situations or unexpected outages in power plants or in the electricity network, which can make the supply of peak load extremely expensive (or even technically impossible). Another form of Demand Response is the use of electric storage heating systems for domestic and commercial consumers, whose heat reservoirs can be charged during nights, when electricity demand is usually low, and which can discharge the heat during the day when there is a higher demand for space heating and overall electricity demand is high. For this and other purposes, simple "time-of-use" electricity tariffs have been developed and used, which pre-define certain hours of the day as low tariff periods and other hours as high tariff periods. The usage of electric devices such as storage heating is supported by triggering signals which are broadcasted either through the electricity networks (by a simplified form of powerline communication) or through radio signals, and which switch the devices designed for operation during low tariff periods on and off (IEA 2006) (Strbac 2008).

Until now, Demand Response is mostly used for clipping demand peaks and thus for smoothening the shape of the load curve. However, due to the rising shares of variable and intermittent generation from wind and solar energy, Demand Response will tend to be used in the future to match the demand to a variable generation system. Thus there will be a gradual shift of paradigm from the previous theoretic optimum of a flat load curve, which was related to a high share of fossil and nuclear baseload power plants, to a new optimum of a generally more flexible load curve, which might aim to match peaks of renewable energy generation with peaks of demand.

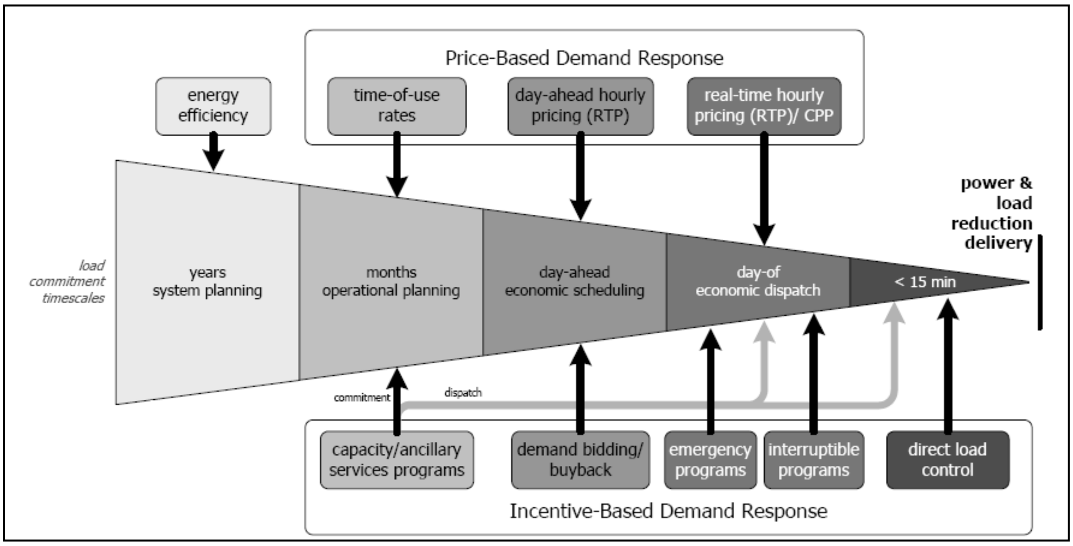

Figure 15: Types and applications of Demand Response Measures.

Source: (U.S.Department of Energy 2006)

A useful categorisation of the types of Demand Response measures and their utilisation in the management of electricity systems has been given by (U.S.Department of energy 2006).

Figure *15* illustrates that different types of Demand Response can be used at different points in time in relation to the interval of production and consumption of the energy in question. This illustrates that only some of the Demand Response measures are suited to managing the impact of short-term deviations from the forecasts of the RES-E generation, whereas other measures might be suited to dealing with predictable intermittencies.

It can be assumed that Demand Response for industrial and commercial consumers is already being used in most European countries. Time-of-use rates in connection with electric storage heating are widespread in Germany, France and the UK.[16] Programmes for direct load control in the domestic sector typically address domestic air-conditioners, water heaters and swimming pool pumps.

There is only very limited statistical information about the total capacity of Demand Response which is currently being used in Europe. The UCTE[17] has collected data of Demand Response capacities which are expected to be used by transmission system operators (UCTE 2009a). The total capacity of Demand Response expected to be used was 11.6 GW in 2009. This is equivalent to some 19 % of the total installed capacity of wind energy in the UCTE countries in that year.[18] Only eight of the UCTE member countries expect to use Demand Response capacity. However, they represent 78 % of the total maximum load projected for UCTE countries. Compared to the maximum load projected for 2009, the capacity of Demand Response expected to be used ranged from 0.3 % in Germany up to 10 % in Greece and the average across the eight countries was 3.7 %. It is clear that this forecast does not cover all the Demand Response potential currently available in the respective countries, as further demand side options might be used by distribution system operators or suppliers of electricity, which are not covered in the UCTE reports. Other potentials might be available but are not used in the UCTE projections.

The major challenges which are related to an expansion of the current capacity of Demand Response programmes can be summarised as follows:

- In order to harvest new potentials for Demand Response, there needs to be a clear business case for innovators. This requires a supportive regulatory framework and new concepts for how Demand Response can be converted into a marketable product.

[16] The potential for Demand Response through electric storage heating is being reduced by the growing share of gas boilers in the UK (Strbac 2008) and recent regulations in Germany which will replace electric heating by more energy efficient systems.

[17] UCTE is now part of the European Network of Transmission System Operators for Electricity (ENTSO-E).

[18] This value was calculated based on data from (EWEA 2009a).

- Liberalisation of the electricity market brought about the need for vertical unbundling of the electricity sector. Thus, network operation, power generation and supply of electricity are taken care of by separate companies. Adequate mechanisms need to be developed which allow the sharing of economic benefits of harvesting low-cost Demand Response potentials between the different actors in the supply chain of electricity and the consumer.
- Recent technological innovations, notably in information and communication technology (ICT), could enable significant additional Demand Response potential. However, there is the challenge of standardising communication hardware and protocols and the interoperability between ICT technologies and energy consuming devices.
- Some types of Demand Response measures require real-time communication with the end consumer (or its energy consuming devices) and detailed metering of the patterns of energy consumption. Many “Smart Meters” installed in recent years in some countries (e.g. Italy and Sweden) are not supporting advanced Demand Response concepts (interview Torriti). Even for the Smart Meters which are currently being installed in many European countries, it is not clear that they are able to deliver the required functionalities.
- It is likely that a large part of the attractive (low cost and easy to activate) Demand Response potentials of large energy consumers have already been exploited. It is not clear what additional potentials there are and how they could be harvested. In the case of domestic consumers, it is important to win the acceptance and awareness of consumers for Demand Response options.
- At least part of the additional Demand Response potentials in the domestic and small commercial sectors could only be harvested today at relatively high cost. The extent to which cost reductions will be realised in the future – which might make these potentials more attractive – is not yet clear.

8.2 Potentials and uncertainties

There are only a very few studies which provide estimates on the future potential of Demand Response in Europe. In its 2009 System Adequacy Forecast, UCTE expected only a moderate increase in the Demand Response capacity to be used by transmission system operators in the UCTE region (UCTE 2009a). This capacity was expected to rise from 11.6 GW in 2009 to 14.2 GW in 2020. The 2010 report produced by ENTSO-E does not change this picture.

A model calculation of the Demand Response potentials in Europe undertaken by Capgemini consultants and VaasaETT suggests a total potential of peak reduction through load-shifting measures of 28 GW in a moderate scenario and 72 GW in a more advanced scenario (Capgemini 2008). In a study which focused on the possibilities of Demand Response activities through electric appliances operated by domestic consumers in Europe (including electric heating), a theoretical potential of 60 GW was estimated in this segment in the EU, Norway and Switzerland for the year 2025, of which some 40 GW could be economically viable (Timpe 2009). However, this study points out that not all of this potential might actually be accessible through Demand Response measures and more research is needed to provide better data on Demand Response potentials by domestic appliances. Most prominently, the acceptance of domestic consumers for Demand Response measures needs to be tested further. A number of other studies have evaluated the DR potential in individual countries.

In their conclusion on Demand Response potentials in Europe, (Torriti et al. 2009) write: "*First, the total amount of DR, as analysed in system adequacy studies, is rather low and flat in recent years. Second, in continental Europe, load management forecasts increased during recent years. Third, studies confirm that most existing DR initiatives consist of interruptible programmes. Fourth, a significant number of European countries do not even consider DR in system and network planning.*"

This overview of the available information shows that there are quite significant uncertainties as to whether and to which extent a significantly larger capacity of Demand Response will be available in the future for the management of European electricity systems. The most relevant uncertainties have already been addressed in chapter 8.1.

8.3 Barriers and requirements for action

Even if the technical potential of Demand Response in Europe is significant, a number of obstacles make it difficult to tap it to support the stability of the electricity system. This chapter lists the most relevant barriers and potential actions to overcome them.

On the technical level, there is still a lack of standardisation as regards the means of communication between utilities and Smart Meters and the meters (or other communication gateways at the premises of the consumer) and the consumers and their energy using devices. This should be overcome by fast progress in standardisation processes, which might be fuelled by the currently ongoing pilot projects of smart meters and Smart Grid concepts on national and European levels. Consequently, a mass rollout of smart meters should be delayed until standardisation has advanced to an adequate level. It should be noted that there are also options for incentivising Demand Response which do not require Smart Meters to be installed, but communication between the network operator or another central agent and the energy consuming devices must be ensured (Seebach et al. 2009).

Moreover, the costs of some of the new technologies required for the provision of Demand Response are still too high to deliver a positive cost-benefit ratio (Timpe 2009). Many Demand Response potentials in the domestic and small commercial sectors are currently not viable. Reductions of the technology costs along learning curves can be expected, but this requires steady support from governments through pilot projects and market introduction programmes (Stamminger 2009).

The stimulation of additional Demand Response options is also hampered by the lack of market pull for such measures. Even relatively simple real-time price information is not available for most of the consumers in Europe (Torriti et al. 2009). Industrial consumers and aggregators of large numbers of domestic consumers could offer products in markets for balancing power and in intraday trading, provided that there is adequate demand and transparent markets are established. In this context it is worth noting that most Demand Response programmes have been managed by vertically integrated utilities up to now. If it is possible to open up business opportunities for independent service providers in the segment of Demand Response, it might help to speed up the exploitation of the potentials.

Further barriers relating to economic incentives are regulated and partly subsidised uniform electricity tariffs which are still predominant in many countries (at least for the domestic sector). However, it should be noted that the regulatory framework for incentivising Demand Response has improved in many countries in recent years (interview Torriti). There is still the challenge of how sufficient incentives for Demand Response can be created in a liberalised and unbundled electricity sector, e.g. by accepting the costs of network operators for Demand Response programmes in the regulated network tariffs.

For the next few years, it will be necessary for governments to continue and expand their financial support for the development and operation of Demand Response pilot schemes (interview Torriti).

In the domestic sector, many consumers may have reservations about an external control of their appliances and data on their energy consumption and usage of individual appliances being analysed by network operators or other agents. Thus it is vital to develop advanced and reliable concepts of ensuring data privacy in Demand Response programs. Similarly, safety and comfort must be fully maintained or even increased compared to conventional appliances if consumers are to accept a more flexible operation. Another barrier is the generally low consumer awareness about the potentials and benefits of Demand Response. The acceptance of Demand Response should be increased by broad consumer education programmes which should include a transparent communication about the benefits of this concept for a low-carbon economy. Last but not least, there must also be clear economic incentives for domestic consumers for their participation in Demand Response programmes, which overcompensate the additional costs of “smart” appliances (Mert 2008). One strategy to overcome the significant barriers faced by Demand Response in the domestic sector could be to rely on simple and fully automatic smart operation of certain appliances, at least as a first step in introducing additional flexibility in this market segment (Timpe 2009).

8.4 Contribution to the potential indicators

Most Demand Response measures consist of a reduction in energy consumption during a certain period, followed by an increase of the consumption (compared to the baseline case with no Demand Response) in a subsequent period, or vice versa. Thus in analytical terms, Demand Response can be treated in a similar way to energy storage. However, there is one major difference: many Demand Response options offer only relatively short periods over which the demand can be shifted, whereas some energy storage technologies allow for much longer periods.

It should also be noted that it is generally very difficult to determine reliable capacity figures for Demand Response programmes (interview Torriti). Thus, actually determining the capacity provided by Demand Response options from the indicators mentioned below will be a demanding task.

8.4.1 Provision of balancing power

In order to enable short-term reaction to load management signals, Demand Response options must be fully automatic and show immediate effect. This applies only to direct load control options, whereby the agent operating the Demand Response actions can directly switch loads on or off. This option is being used in several European countries for some industrial applications as well as air conditioning systems, hot water storage boilers and pumps for swimming pools and similar facilities. As the Smart-A project has shown, a fully automatic reaction to load management signals would also be possible in the future for refrigerators and freezers, once they are equipped with the respective controls (Stamminger 2008). For broadcasting the load control signal, power line communication (PLC) is typically being used. In some cases, radio transmitted signals are also in use.

8.4.2 Provision of short-term backup power

Similar to balancing power, short-term backup power must also be available at very short notice. The difference is that backup power might be needed for a longer period, which can last between 15 minutes and up to several hours. Similar to the case of balancing power, Demand Response will only be able to provide short-term backup power if the load change can be triggered directly by the agent operating the Demand Response actions; no consumer interaction is required. Thus in the first instance, the same options can be used as mentioned in the previous section. However, if the need for backup power continues for a longer period (e.g. longer than 30 mins.), other Demand Response options may also come into play, such as real-time pricing or critical peak pricing.

8.4.3 Provision of longer-term secured capacity

Typically, Demand Response is not able to provide longer-term secured capacity. This is due to the limited time lag between load reduction and load recovery, which cannot be longer than a few hours for most Demand Response options, and can be up to 24 hours or more for a very few options only.

8.5 Scenarios for future developments

Given the significant challenges and barriers involved in the further expansion of Demand Response capacities, it is very difficult to predict the future development of Demand Response in Europe. Two alternative scenarios can be used to describe the likely range of Demand Response in the future. However, due to the lack of reliable data, these scenarios can only partly be described in quantitative terms.

In an optimistic scenario, the current capacities of Demand Response are expanded significantly both in industrial and commercial applications and in the domestic sector. An additional resource for Demand Response is added by electric vehicles which become relevant after 2020, including the possibility of feeding back energy from the vehicle batteries into the electricity grid (vehicle-to-grid). In this optimistic scenario the total available Demand Response capacity might amount to up to 20 % of peak demand by 2030 (interview Torriti).

In a more pessimistic scenario, part of the current capacities of Demand Response will fall away because many European countries are replacing electric heating and hot water systems with renewable thermal energy and energy efficiency measures. Only limited additional Demand Response capacity is added, based on new options such as real-time pricing using Smart Meters. The deployment of electric vehicles is slower than anticipated and the vehicle-to-grid concept cannot be implemented on a larger scale due to technological problems. In this pessimistic scenario, the total Demand Response capacity might remain below 4 % of the peak demand.

9 Conclusions

Taking into account the ambitious plans for the development of electricity from RES in Europe it is obvious that significant changes are needed in European electricity systems. This is due to the fact that notably wind and solar energy can be harvested best at locations which are neither close to the centres of demand nor close to current major transmission lines. Furthermore, the variability and intermittency of wind and solar generation requires an improved ability to exchange large volumes of electricity between different regions in Europe. Finally, the electricity systems must become more flexible in order to deal with variations in the renewable energy supply.

The most important measures for improving the ability to integrate large volumes of renewable electricity into the electricity system are large-scale investments in the expansion of the transmission networks and the expansion of storage facilities.

Expanding the grid not only concerns the connection of new generation centres, e.g. offshore wind, to major nodes of the current grid, but also reinforcements of the existing grid in order to manage the new patterns of load flows. Moreover, the capacities of existing lines can be expanded by new technologies. It is worth mentioning that some of the onshore grid reinforcements under discussion today are needed first of all in order to improve security of supply and to support the internal market for electricity; thus they would have been required even without a future RES expansion.

It is too early to decide the extent to which a new European-wide “supergrid” is needed. New grid infrastructures are needed in the short term for the connection of offshore wind to the neighbouring countries. Some of these might be using new technologies such as HVDC lines. Whether substantial reinforcements of the existing onshore grids are sufficient or whether it is sensible in the longer term to develop a large new “supergrid” structure across Europe requires further analysis.

In addition to installing “more copper”, the operation of the grid as well as generation and demand needs to be made more flexible. Truly “smart” grids can help to reduce the stress on the transmission and the distribution systems. They also support the balancing of variable and intermittent generation from RES. Both measures are needed for the integration of large shares of RES generation.

- A more flexible operation of conventional power plants will support the system integration of intermittent RES. Gas-fired power plants, which can generate electricity at lower CO_2 emissions than plants using other fossil fuels, will play an important role in this. The installed capacity of gas-fired plants is projected to grow by 50% until 2030.

- Expansion of storage will be important since storage can provide flexibility in a way that other flexibility options cannot, especially in terms of long-term storage. This will become increasingly important as the share of renewables increases and flexibility is needed to increase the share of RES that can be accommodated in the system. This will also improve the economics of storage as storage then starts competing with burning fossil fuels. Nevertheless, it is not yet clear whether and how different new storage options can become economically viable.

- Increased flexibility of electricity demand can also support the integration of RES. However, the potentials of economically viable Demand Response measures accepted by energy consumers are limited. Optimistic scenarios assume that up to 20% of the peak load might become flexible. It must also be noted that the duration of load shifting by Demand Response is usually limited to short periods of up to a few hours. This will help to deal with forecasting errors in renewable energy production, but cannot support the management of longer-term variations in wind and solar generation.
- Finally, with an increasing share of intermittent RES, these plants will also have to support system stability with at least a limited flexibility. Technical solutions under discussion consist of intelligent inverters and centralised control of downward regulation. However, curtailment of renewable energy generation will require more energy produced from fossil fuels, thereby increasing CO_2 emissions.

Clearly, there is a need for more transparency on the actual readiness of regional electricity systems to integrate high shares of RES. For this purpose, more research should be devoted to the development and monitoring of adequate indicators as have been described in the individual sections of this report. Furthermore, the interaction of smart grid operation at the distribution level and the transmission level should be analysed in more detail.

The most important political conclusions from the analysis in this report can be summarised as follows:

- As the mid-term (2020) and longer-term targets for RES become clear, attention should not only be given to the support systems and financing of RES production devices, but also to their technical integration into the electricity system. Besides the question of sufficient grid capacity which connects the new generation centres with the demand centres, this also includes questions regarding the remaining balancing power capacity in order to ensure stable system operation.
- Major attention should be given to an adequate development of the electricity grids. New and upgraded transmission lines are important infrastructure projects which need significant investments and long lead periods for authorisation. Therefore the planning of the grid infrastructure of the future must be a high priority and today's planning should not only look at the year 2020, but also at the needs expected for 2040 and 2050, by which time electricity will need to be mostly decarbonised.

- Since stronger grids cannot solve all the problems of RES integration, the different options for making the electricity system more flexible need to be exploited as well. Funding and regulatory support should be focused on those technologies and services which actually support the flexibility of conventional generation and grid operation, including new storage options as well as Demand Response.
- Furthermore, with renewable electricity technologies gradually reaching competitiveness, further strategies for the (economic) integration of RES into the electricity markets are required. Already within the current framework of production support and priority grid access, renewable generators can support system management and thus may create additional revenues. As the different renewable technologies become viable, public support can gradually be phased out. However, this requires a level playing field for all generators and a market framework which does not discriminate against renewable energy.
- Additional work for the future that seems worthwhile for EEA to expand on are:

  a) Smart grids and flexible demand options and barriers
  b) Options and economics of electrical and heat storage facilities in Europe
  c) Calculation of the proposed indicators
  d) Overall integration and synthesis of current and the three proposed reports.

10 Abbreviations

CAES	Compressed-air energy storage
CCS	Carbon capture and storage
CHP	Combined heat and power
CSP	Concentrated solar power
DG	Distributed Generation
DR	Demand Response
EEA	European Environmental Agency
EEG	Erneuerbare-Energien-Gesetz (German Renewable Energy Sources Act)
ENTSO-E	European Network of Transmission System Operators for Electricity
EnWG	Energiewirtschaftsgesetz (German Energy Industry Act)
EREC	European Renewable Energy Council
ETS	European CO_2 Emissions Trading Scheme
EWEA	European Wind Energy Association
FACTS	Flexible AC Transmission
FLM	Flexible Line Management
GW	Gigawatt = 10^9 Watt
HTLS	High Temperature Low Sag
HVDC	High Voltage Direct Current
ICT	Information and communication technologies
IEA	International Energy Agency
JRC	Joint Research Centre
OCGT	Open-cycle gas turbine
PLC	Powerline communication
PV	Photovoltaic power
RES	Renewable energy sources
RES-E	Electricity from renewable energy sources
SET plan	European Strategic Energy Technology Plan
TYNDP	Ten Year Network Development Plan (of ENTSO-E)
UCTE	Union for the Co-ordination of Transmission of Electricity

11 Interviewed Experts

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