

INTERNATIONAL ENERGY AGENCY



VARIABILITY OF WIND POWER AND OTHER RENEWABLES

Management
options and strategies

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Executive Summary

This working paper links the current debate about the 'intermittency' of wind power into the wider context of natural cycles of resource availability of all renewable energy technologies. It investigates whether there are technical limits to the market penetration of renewable energy technologies due to these cycles and it discusses some of the economic implications and outlines key cost variables. Being an inherent aspect of the renewable resource, they are, in the case of mature renewable energy technologies such as hydropower, biomass and geothermal, well understood and managed. 'New' renewable energy technologies such as wind power or solar PV have surfaced prominently in recent discussions among policy-makers, researchers and the media for two main reasons: Firstly, the rapid growth, especially of wind power, led to significant market share in some countries within a short timeframe thus magnifying grid integration issues. Secondly, these technologies introduce a new quality of natural cycles in that they can fluctuate over short timescales intra-day and intra-hourly which requires different management strategies than previously established. In the case of wind energy, it is analyzed how this affects the possibility of integrating renewables into electricity grids on a larger scale.

This review comes to the conclusion that a number of measures are necessary to integrate wind energy and other renewables into modern electricity grids, even though the fundamental technical principles are not new. The geographical aggregation of generators such as wind turbines reduces the volatility of output. Improved forecasting methods will make it more predictable. Both aspects are already widely used in electricity markets. Furthermore, careful attention needs to be paid to the provision of backup and reserve capacities and the timely extension of transmission and distribution grids in order to ensure system stability at all times. In particular, transboundary electricity exchange is going to play an increasing role which will have to be assessed. Although these issues are also central to market liberalisation and security of supply concerns, they will become even more important with increasing market penetration of wind power. Finally, as each renewable energy technology fluctuates over a different time-scale, important gains from the complementarity of these cycles can be achieved.

Beyond the above mentioned technical issues, the extent to which the intermittency of natural resources will become a barrier to renewables is mainly a question of economics and market organisation. Grid extensions and the provision of reserves which are attributable to wind power come at costs which have to be taken into account when considering the overall economics of wind power. The precise costs depend on a number of factors, including the level of market penetration of wind power, the availability of the renewable resource, the state of the existing grid and current technology mix. Transparent, inter-connected and well-functioning markets help to minimise these grid integration costs. This may require structural adaptation in some cases. In this context, market gate-closure times between final declaration of forecasted generation and actual real-time usage play an important role; weather forecasting and modelling techniques become more precise the closer they are to real time, thus shorter gate closure times would allow for more precise output estimates and consequently better management. Currently, some markets are still designed with long gate-closure times which impose additional economic costs which are not necessarily based on technical needs. Taking this into account produces the right incentives for the development of a portfolio of options to manage intermittency, including flexible new plants, storage technologies, distributed generation and demand-side response techniques.

This study draws mainly on experiences in Denmark and Germany and some theoretical analyses. In order to provide a more complete picture, in future analyses more countries will have to be considered and effects of trans-boundary electricity flows will have to be taken into account in more detail.

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1. Introduction

In many IEA countries, renewable energy technologies receive increasing attention and with the latest International Renewable Energy Conference in Bonn, 2004, several countries have set ambitious targets for renewables. As a result, the World Energy Outlook 2004 expects all renewables to account for a share of 19% in world electricity generation 2030 in the reference scenario, and even 24% in the alternative policy scenario (IEA 2004b).

Especially the electricity sector experiences major increases in renewables market penetration, accounting for 15.1% in IEA member countries in 2001 already, with hydropower providing some 13% (IEA, 2004a). 'Traditional' technologies such as hydropower and geothermal have maintained or increased their participation in the primary energy supply in some non-IEA countries around the world. In IEA member countries, despite the decreasing share of these 'traditional' technologies in total electricity production since the early 1970's, renewables are likely to play a more important role in the medium- to long-term. With the entry into force of the Kyoto-Protocol and the advent of an emissions trading-scheme among EU-member countries, first steps are now under way to include the costs of CO₂ emissions in energy markets. Already, 'new' renewable technologies such as wind and solar exhibit high annual growth rates in Total Primary Energy Supply (TPES). At current trends, this will ultimately lead to an overall increase, as shown in table 1.

Table 1: Average annual growth rates of renewable energy sources in IEA member countries in TPES in %

	1970-1980	1980-1990	1990-2001
Renewables	3.2	2.4	1.2
Biomass	3.5	3.0	1.6
Hydro	2.6	0.7	0.4
Geothermal	8.3	9.4	0.4
Solar PV/Wind	6.4	23.5	23.1

Source: IEA 2004a:43

In this light, the integration of larger amounts of renewables will become an increasingly important issue for the management of electricity grids. This comes at a time when demand for electricity continues to rise and electricity markets themselves are undergoing a series of institutional and technical changes, opening up to new market actors and re-organising the operation of key market segments. Traditional top-down approaches with only one company controlling all segments of the power market, delivering power from a small number of power plants with high capacity ratings, are broken up. Instead, the market is going through a liberalisation process, moving away from monopolistic approaches to electricity generation and retailing, allowing for an increasing number of players on all levels of the market - be it power production, distribution or transmission.

Today's electricity markets, in going through a market liberalisation process, can also open up more opportunities for decentralised and more flexible power generation from renewable energies, combined-heat and power plants (CHP) or gas turbines, depending on the regulatory structure. These developments have given rise to new technical challenges but also new opportunities for transmission and distribution grid operators.

With higher market penetrations of renewable energy technologies, however, some electricity systems in IEA countries will increasingly need to cope with an important variable: natural cycles of renewable energies. Natural cycles relate to a phenomenon, which all renewable energies have in common, as will subsequently be shown. Renewables by their very nature vary their output with natural conditions, albeit, depending on the technology, on different timescales. These fluctuations of renewable electricity output can pose challenges in managing electricity grids. On the other hand, hydropower (pumped-storage) has been used for a long time to level out short- and mid-term fluctuations in electricity production and consumption. Hence, the issue of unmatched demand and supply is not completely new and in many cases understood.

The most prominent example in media and policy discussions is wind power, where the natural fluctuations have received a great deal of attention in recent years and have led to concerns about wind integration. Regions such as Western Denmark and Northern Germany, where wind penetration levels have become significant, have become "case studies" for the integration of renewables in general, and wind power in particular. The challenges that the high share of wind power poses both for these countries and its neighbours are highlighted in chapter 3.

On the question of wind intermittency, a lot of research has been carried out on the American and European electricity markets. Initially, it was believed that only a small amount of intermittent capacity was permissible on the grid without compromising system stability. However, with practical experience gathering, for example in the Western Danish region where over 20% of the yearly electricity load is covered with wind energy, this view has been refuted. Instead of rejecting intermittent technologies outright for want of dispatchable capacity, a number of papers have recently focused on management techniques that minimise disruption to the grid and thus allow for higher penetration of renewable technologies.

Nevertheless, the questions whether natural cycles of renewables have impacts on renewable energy market potential, and whether there are upper limits to renewable energy share in electricity supply, have become critical for policy-makers. This study reviews and draws together the existing literature from a number of countries and puts it into the context of the current debate. It thus presents the current thinking on the technical and policy implications of variable electricity supply from renewable energy sources and offers insights and methodological guidance for interested parties who want to assess these issues within their own national circumstances. In chapter 2, it will give a detailed overview on the natural cycles of different renewable energy technologies to provide a context for the subsequent chapters. Chapter 3 will focus on the currently prominent example of the integration of wind power into electricity grids as an example for renewable energies in general. Options for grid management, reserves and policy are outlined and a review of current cost estimates of system integration is presented. Chapter 4 will summarise the key technical and policy challenges that arise for the system integration of wind while chapter 5 will broaden the picture and analyse the wider lessons learned for the integration of all renewable energy technologies into electricity grids and conclude.

2. Natural Cycles of Renewables Energy Technologies

Overview

All renewable technologies ultimately derive energy from natural sources that vary in their availability over different timescales. Even fossil fuels like oil, gas and coal have natural cycles of regeneration which, however, occur on a timescale several orders of magnitude longer than what is discussed in the context of this study.

In this chapter, an overview will be given on some key renewable technologies and the natural cycles on which they depend. These can range from changes occurring over decades, as in the case of geothermal technology, to minute-by-minute changes of cloud cover which, for example, affect Solar PV arrays.

As noted in the introduction, the natural cycle of wind has frequently received the greatest amount of attention by policy makers, industry and the media. Undeniably, the varying output of wind energy could destabilise electricity grids if no precautions are taken. However, the large-scale blackouts that have been witnessed in Western Europe and North America in recent years were completely unrelated to the wind energy installed in the respective countries.

Two factors have especially contributed to the prominence of the fluctuation of wind power in public awareness. Firstly, it has seen rapid growth in a number of countries, raising its share of electricity production to a significant proportion within a short amount of time. Secondly, it has introduced a new quality of intermittent supply which has been less important for other technologies, namely, that of intra-day and intra-hourly output changes.

Two Large scale research projects in Europe, the IRED-Cluster ("Integration of Renewable Energy Sources and Distributed Generation into the European Electricity Grid") and EU-DEEP ("The birth of a European Distributed EnERgy Partnership that will help the large-scale implementation of distributed energy resources in Europe"), have analysed and continue to examine the options and challenges to integrate renewable energy sources and notably wind energy into existing electricity grids.¹ The National Renewable Energy Laboratories (NREL) and Sandia National Laboratories in the US have a continuous research programme on grid-integration challenges of wind power.

In this context, the following paragraphs aim to show how the fluctuation of wind is part of the wider picture of variations in natural resources that affect a range of technologies, many of which have been used for long periods of times. Methods have been developed to successfully cope with seasonal fluctuations of a variety of technologies. Following research and development (R&D) efforts that were spurred by the oil price shock in the 1970s, three technologies became especially prominent²: Hydropower, geothermal and biomass. All three technologies have an inherent element of natural cycles which will be reviewed in the following paragraphs. The 'new' renewable energy technologies that are currently developed introduce new qualities of natural cycles. The main technologies considered for this section are solar PV, wind and wave/tidal.

1. More information on these research projects can be found on the websites www.ired-cluster.org and www.eu-deep.com.

2. See also IEA (2004a), which gives a timeline of IEA member countries' R&D efforts in renewable energy technologies.

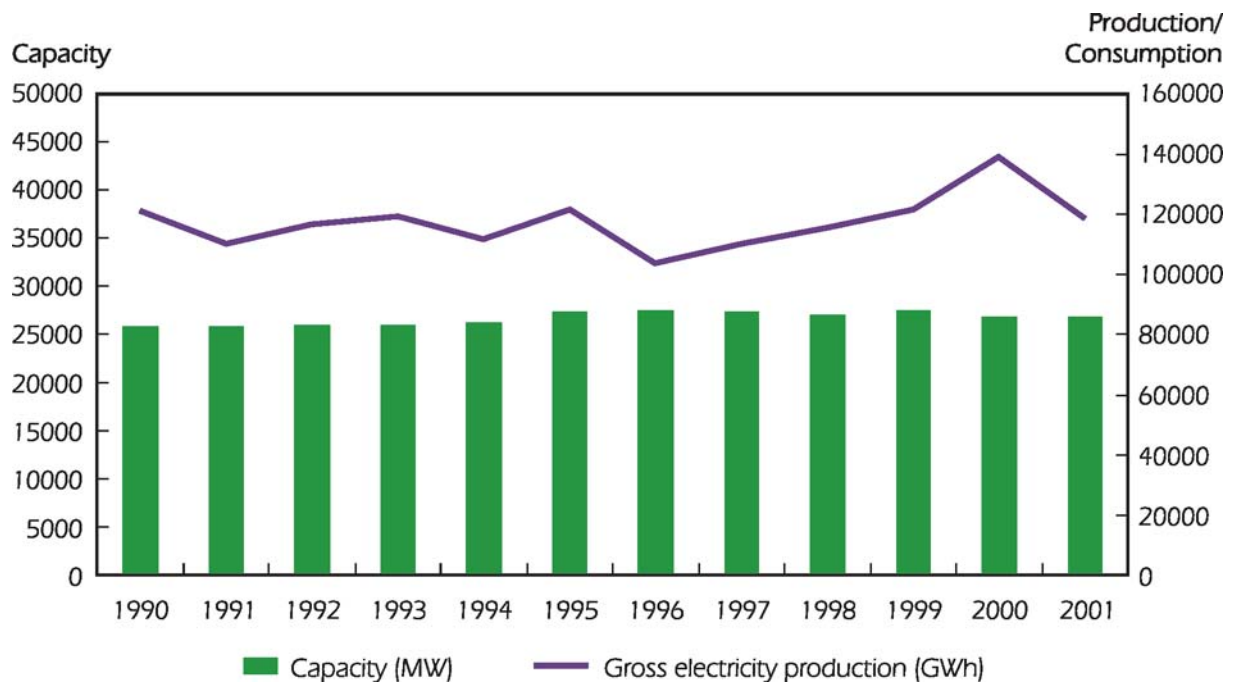
Hydropower

Hydropower plants had a 16.2% share in global electricity production in 2002. The two most important types of hydropower plants considered here are run-of-river plants and dams. The capacity of a hydro plant to produce electricity ultimately depends on the water cycle providing seasonal rain and runoff from snow pack. This has slightly different impacts in each of the two methods. Run-of-river plants produce electricity according to the flow of water in the river it has been built in. Water is shored at low-head hydroelectric plants and channeled through turbines using the natural force of the river flow. Seasonal variations determine the water level in the river and thus the strength of the water flow and its implicit available energy. Dams are often built in mountainous regions where the natural topography can be used to create artificial lakes at low costs. The runoff from rain and snow is thus collected and funnelled through dedicated pipes into a powerhouse downstream where it powers a turbine. Again, seasonal variability determines the availability of water and thus the total potential energy that can be stored in the artificial lakes.

Hydropower today is the main energy carrier to store electricity at a large-scale. Besides the natural accumulation of water in reservoirs, pumped-storage facilities offer the opportunity to pump water and thus potential energy upstream and release it again when required. The typical round-trip efficiency of this method is around 80%. The benefits of pumped-hydro storage reservoirs are further examined in chapter 3.

Figure 1 shows the experience of Norway, a country whose electricity system is 99% dependent on hydro power. For example, between 1995 and 1996, actual annual electricity production from hydro power dropped by about 17,000 GWh. This can be attributed to low annual rainfalls and thus lower potential energy to be utilised by hydro power plants. Conversely, between 1999 and 2000, annual hydroelectricity production rose by about 15,000 GWh.

Figure 1: Hydropower capacity and electricity production in Norway



Source: IEA, 2004a:510

Drought periods can become a problem when they coincide with periods of high electricity demand. For example in southern climates, hot periods are often associated with annual peak demand on the system as well as relative droughts.

Geothermal

Geothermal is energy available as heat emitted from within the earth, usually in the form of hot water or steam. Geothermal heat has two sources: the original heat produced from the formation of the earth by gravitational collapse and the heat produced by the radioactive decay of various isotopes. It is very site dependent and can be used for heating and power generation purposes. Since the earth's crust is continuously emitting heat towards its surface at a rate of 40 million megawatts, geothermal is in principle an inexhaustible energy source, with the centre of the earth having cooled down by only about 2% over the earth's lifetime of about 4 billion years.

There are no problems of intermittency in the utilisation of geothermal energy sources for direct heat applications or for electricity generation. A developed geothermal field provides what is essentially a distributed heat source, since the input to a power plant normally consists of the integrated outputs of several wells. Thus one or more wells may be shut for repairs or maintenance while others produce; proper dimensioning of the generating plant ensures that there is always enough steam or hot water available for operation. This feature and the low operational costs are the reasons why geothermal power plants are normally used as base load.

Natural variations of geothermal resources occur over extremely long periods, millennia or even longer time scales. However, man-induced processes lead to variations with shorter time-scales, typically in the range of decades.

Unwanted effects of over-exploitation and improper reinjection have been observed, especially in the early years of development of geothermal technology. However, present-day geothermal technology for field characterisation and modelling makes it possible to avoid improper practices, or at worst to detect their effects at an early stage before they become significant.

Biomass

Biomass can be used for a great variety of energy needs, from heating and transport fuel to power generation. There are technologies for using biomass as liquid and gaseous fuel, as well as traditional applications of direct combustion. The basis for all these applications is organic matter, in most cases plants and trees. There is a trend towards purposefully planted biomass crops although biomass can also be collected as a by-product and residue from forestry, industry and household waste.

It is projected that growth in biomass applications in IEA countries will mostly come from new technologies that depend on dedicated plantations and by-products from sustainable forestry. Thus, the supply of biomass depends to a significant extent on the seasonal cycle of these dedicated plants. To increase the use of biomass for electricity generation and heat production, there is an increasing focus on dedicated energy crops such as short-rotation coppice which allow frequent harvest cycles per year. The area that can be thus planted and the number of harvests per year will determine the maximum amount of energy that can be derived in this way. Should the use of biomass increase in all its applications, these limitations might become more pronounced.

A second, albeit man-made, variability arises when biomass is used in combined-heat-and-power plants (CHP). For example, in the Scandinavian countries, combined heat and power production is dominant for biomass. For industry residues this production is quite constant over the year but for district heating this results in electricity production of biomass having seasonal variation (production high at winter with high heat load), as well as some daily variations, according to temperature/heat load.

In principle, a global market for biomass products can be envisaged taking advantage of different climates and types of vegetation around the world. There is an increasing interest in ethanol as an alternative transport fuel but currently few countries plant significant amounts of plants such as sugar cane for this purpose. Brazil, one of the forerunners in this field, is a major exporter of this product with a volume of about 800 million litres and some 25% of the world's ethanol export market. The Netherlands forecast a significant biomass market in Europe in their energy transition strategy with major supplies expected to come from Scandinavian forestry. The boundaries that seasonal cycles put on the maximum amount of energy derived from biomass can thus be extended, but will ultimately run into competition from other land use interests and possibly competing uses of biomass itself. If current growth forecasts of biomass usage become reality seasonal cycles will surface more prominently on the policy agenda.

Solar PV

Photovoltaic cells convert sun light directly into electrical energy. The amount of energy that can be produced is directly dependent on the sunshine intensity and the angle at which solar PV cells are radiated. Thus, for example, PV cells are capable of producing electricity even in winter and even during cloudy weather albeit at a reduced rate. Natural cycles in the context of PV cells thus have three dimensions. As with the previously discussed technologies, it has a seasonal variation in potential electricity production with the peak in summer although in principle PV cells operating along the equator have an almost constant exploitable potential throughout the year. Secondly, electricity production varies on a diurnal basis from dawn to dusk peaking during mid-day. Finally, short-term fluctuation of weather conditions, including clouds and rain fall, impact on the inter-hourly amount of electricity that can be harvested. Short-term fluctuations are reduced by geographically distributed PV production.

Wind

Wind turbines convert wind power into electrical energy. The amount of energy that can be produced is directly dependent on the wind speed, more precisely on the cube of the wind speed. The wind speeds, at which wind turbines commonly operate, are between 2.5 to 25 m/s. Thus, wind power can become unavailable at times of low wind speeds, but also at times of very high wind speed, when wind turbines need to be shut down in order to avoid damage of equipment.

Wind power can fluctuate at various time scales; it is subject to seasonal variations of peak electricity production in winter or summer depending on the region, as well as diurnal and hourly changes. Generally, very short-term fluctuations - in the intra-minute and inter-minute timeframe - are small relative to installed capacity, compared to hourly or daily variations and levelled out when considering larger areas of production. Furthermore, wind forecasting and aggregation of wind turbines mitigate against short-term fluctuations, a topic which will be elaborated in chapter 3. Ultimately, the degree of variations is also very site dependent, as for example see breezes are much more constant than are land breezes.

Wave/Tidal

Utilizing the energy of the World's Oceans provides a very promising approach to produce electricity. However, despite a rather big potential, ocean energy systems have not yet passed the stage of demonstration projects and are yet limited to a few selected sites due to several drawbacks (technology related, location related, and economics). Although large ocean areas provide for a rather stable environment, wave and tidal power generation shows intermittent aspects as well.

Tides are generated by the rotation of the earth, causing periodical movements of the oceans' surface according to three interacting cycles:

- A half-day cycle caused by the rotation of the earth within the rotational field of the moon results in tidal movements every 12 hours and 25 minutes.
- A 14-day cycle based on the superposition of the gravitational fields of moon and sun.
- Interaction of the gravitational fields of sun and moon at new and full moon result in maximum spring tides. Minimum neap tides occur at quarter phases of the moon, when the sun's force of attraction cancels out that of the moon.

As these movements are generally well understood, the variability of tidal energy is highly predictable. Still, output from tidal plants varies by a factor of four over a spring-neap cycle (Pontes et al. 2001).

Wave energy largely depends on wind: Wind speed, duration of wind blow and fetch define the amount of energy transferred. Despite this wind dependency, fluctuations of wave energy are different, as waves in deep water lose their energy and by this smooth out only slowly and therefore can travel long distances. Wave energy, however, is subject to cyclic fluctuation as well, dominated by wave periods and wave heights. This lets power levels vary both on a daily and monthly basis, with seasonal variations being less in more temperate zones.

Summary

As discussed above, cyclic changes refer to the natural variability of renewable energy resources and are therefore a general phenomenon of all renewable energies. One can refer to natural cycles both as a relatively short-term (intra-day or inter-day) variation in output as well as a long-term variation (seasonal changes). Figure 2 summarises the time-scales over which the various technologies operate.

Since natural variations of resource availability do not necessarily correspond with the (also varying) need of the consumers, balancing supply and demand is a critical issue, potentially requiring backup by other means of energy supply. The variations can occur at any time-scale: hourly changes in output require balancing of short-term fluctuations by the so-called 'operational reserve', while days with low output require balancing of longer-term output fluctuations by so-called 'capacity reserves', as further discussed in chapter 3. Conversely, exceptionally windy days or rainy seasons can produce a surplus of supply and their might be an issue of handling excess capacity where grids are not sufficiently interconnected.

On the other hand, hydropower has played an important role as backup power and electricity storage for years. Together with other renewables such as biomass and geothermal it also has the potential to serve as backup power as shares of renewables in electricity supply increase.

Figure 2: Timescales of natural cycles of renewable energies



Currently, natural cycles of renewables have become an issue to grid operations on a regional level because of fluctuations in hydropower and wind. Other technologies have either not yet reached a level of penetration where their variations are of importance for balancing the electricity system, or have been integrated relatively successful.

In summary, although natural cycles of renewables have usually been considered in the context of wind power (“intermittency”³), this does not have to be the case, as has been demonstrated above. In the future, the wider application of other renewable energy technologies such as solar energy and biomass might necessitate similar analysis. Although natural cycles are inherent in all renewable technologies, solutions were found to manage them as in the case of hydropower. Norway’s electricity production, for example, is 99% based on hydro power but it has to be prepared to cope with years of below-average as well as above-average rainfall to maintain its electricity supply. The main avenue used to cope with these fluctuations is hydro-storage and interconnection with its neighbouring countries in Scandinavia and a concomitant market liberalisation that allows for transparent signalling of supply shortages and overcapacities to induce market participants to adjust supply into and out of Norway when necessary. This issue will be re-examined when discussing the variability of wind in chapter 3.

As figure 2 showed, natural cycles of renewables operate over different time-scales. Utilising a variety of technologies that draw on a range of renewable resources will reduce the risk of any one cycle having a critical bearing on the system balance and will thus reduce costs. In fact, in a number of studies that will be considered in this report, a portfolio of renewable energy technologies have been considered concomitantly. One study by Sinden (2002) considered the optimal portfolio of renewables to supply a targeted amount of electricity per year. It found that requirements for backup

3. For simplicity, the terms ‘natural variability’ and ‘intermittency’ will be used interchangeably. See for example also the definition of the US Energy Information Administration (EIA, 2004): “Intermittent electric generator or intermittent resource: An electric generating plant with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements.”

capacity for wind power could be reduced by almost two thirds if the same amount of electricity is produced by a portfolio of renewable energy technologies rather than by wind power alone.

The two regions, where the natural variation of wind (often referred to as "intermittency") is currently most discussed in the context of changes to system operations are Western Denmark and Northern Germany, where wind power penetration has reached a considerable level, albeit a number of countries like the USA, UK, Portugal and Spain are investigating the demands on their grids as they expect wind to grow further in the near future. It is advisable for countries with ambitious renewable energy targets to discuss intermittency of wind and fluctuation of other renewables as early in the process as possible, and the efforts which are undertaken in a number of countries in this respect are commendable. The following chapter will now present a review of the issues associated with integrating wind energy into the electricity grid.

3. Integrating Wind into Electricity Grids

As noted in the previous section, the fluctuation of wind energy has recently received a great amount of attention in policy-making, academia and the media. New policies to integrate wind energy into existing electricity grids are currently formulated, major research initiatives investigate the challenges associated with this task and reports about the costs and benefits of wind energy are a frequent topic in the media. The recent fast growth in installed wind capacity in many countries and associated cost reductions mean that wind energy is considered one of the most important 'new' renewable energy source in the near-future. In order to illustrate the demands that the natural cycles of renewables can place on electricity grids, this chapter will discuss in depth the challenges that wind power poses to system operations.

Generally, the strategies to address the intermittency of wind vary between different national or regional grids. Important factors are the degree of interconnection, the natural resource and the availability of flexible generation capacity. In the first part, challenges that can arise with wind intermittency on the grid are presented. Here, grid operations are described and the functions of operational and capacity reserves are explained. Subsequently, the various options for mitigating the problems of wind intermittency are reviewed. Finally, cost estimates and market practices in a number of IEA countries are examined. Chapter 4 will then discuss some of the technical and policy lessons from this chapter in summary and conclude.

Grid operation and ancillary services

The term operation refers to daily and longer-term grid-management both on a distribution as well as a transmission level. Commonly, however, the distribution grid is not actively managed and plays only a passive role; this may change in the future due to different factors such as an increase of distributed generation. At present, however, the transmission network mostly manages the balancing of supply and demand.

As large energy systems operate with little storage capacities mostly for economic reasons, the guiding principle is to balance demand and supply continuously and, where necessary, to replace other capacity within very short lead times. As each national electricity system operates under tight security and quality standards, these so-called 'ancillary services' have to be relied on to 'secure' and 'fine-tune' the electricity provided, independent of whether intermittent renewables are connected to the grid or not.

Firstly, security standards dictate that the electricity grid must be designed to withstand outages of certain magnitude and high loads without losing service, so-called 'N-1' or 'N-2' events. Overall system reliability is determined by the 'loss-of-load probability' (LOLP) which can be defined as "the probability that the load will exceed the available generation" (Jenkins et al. 2000).

Secondly, quality standards define the exact nature of the electricity service delivered, the frequency and voltage being two important variables of this. This mandates that the operator keeps variations in frequency and voltage within specified limits so as not to damage electrical appliances.

Keeping these criteria in mind, an operator has to enable enough reserve capacity to be able to maintain the specified security and quality of electricity supply in the face of major events. Two

commonly considered events are the outage of the largest individual generating unit on the grid or the loss of the most significant transmission line. In the first case, these are typically large power stations like the Sizewell B nuclear power station in the UK (1188 MW), in the latter case this could similar be high-voltage transmission lines in the 1000 MW-class such as the interconnector between Germany and Denmark, for example.

These reserves are operating over different time-scales and many countries operate distinct markets for each of them. The exact definitions vary between countries, but typically, there is a short-term dimension to reserves with a market for 'spinning reserve' or 'fast-response' capacity, which is able to come online within seconds. Next, there is a more medium-term dimension to reserves that can come online within minutes to quarter of an hour. The actual operational act of buying or selling energy in the short-run is typically referred to as 'balancing'. Finally, there is a longer-term dimension to reserves, which operates over hours and days. An important variable which determines which type of technology is used for each of these timeframes is the time it takes to start up thermal power plants. All three dimensions are reflected in table 2, which shows the setups for three different countries and how these dimensions are understood.

Table 2: Reserve capacities in Germany, Ireland and the United States

	Short-term reserve	Medium-term reserve		Long-term reserve
Germany	Primary reserve: available within 30 seconds, released by TSO	Secondary reserve: available within 5 minutes, released by TSO	Minute reserve: available within 15 minutes, called by TSO from supplier	n/a
Ireland	Primary operating reserve: available within 15 seconds (inertial response/ fast response)	Secondary operating reserve: operates over timeframe of 15-90 seconds	Tertiary response: from 90 seconds onwards (dynamic or static reserve)	n/a
United States	Regulation horizon: 1 minute to 1 hour with 1- to 5-second	Load-following horizons: 1 hour with increments 5- to 10-minute increments (intra-hour) and several hours (inter-hour)		Unit-commitment horizon: 1 day to 1 week with 1-hour time increments

Sources: RWE 2004, SEI 2004, Smith et al. 2004

As the above table shows, reserves are neither defined nor treated equally in different countries. Thus, in order to simplify the ensuing discussion, this paper will in the following refer to the short- and medium-term reserves as operational reserve, whereas the long-term reserve will be labelled capacity reserve.

In the case of wind power, operational reserve is the additional generating reserve needed to ensure that differences between forecast and actual volumes of generation and demand can be met. Again, it has to be noted that already significant amounts of this reserve are operating on the grid due to

the general safety and quality demands of the grid. Wind imposes additional demands only inasmuch as it increases variability and unpredictability. However, these factors are nothing completely new to system operators. By adding another variable, wind power changes the degree of uncertainty, but not the kind - a fact that several authors referred to recently (DeMeo et al. (2003)). Wind power can be aggregated thus evening out imbalances of individual turbines, an issue picked up again in the next section.

Wind power has been referred to as a special case, because differences between forecasts and actual volumes can arise from other than 'common reasons'. Common reasons include planned and unplanned outages of generating plant or on the transmission or distribution networks on the supply side; and predicted and unpredicted changes in consumer demand levels due to TV pickups, weather patterns or other events on the demand side. Wind power, and ultimately all renewable energies if applied to a larger degree, includes another uncertainty on the supply side: unpredicted changes in wind speeds and, thus, altering wind generation levels. The most important tool for addressing this issue is weather forecasting. Significant research has been put into optimizing forecasting and modelling techniques and this will be discussed in more detail further in this chapter.

How balancing and the operational reserve is handled, differs according to the individual country setups. Plants can be literally in 'spinning reserve' mode as they are running below full power and thus have the ability to adjust output very quickly up- or downwards. Hydropower storage facilities can bring on capacity within minutes by opening gates for water. In countries with high penetration of wind power already today and only few flexible power stations or hydropower storage, the question of operational reserves is critical; for economic (as well as environmental) reasons, it is costly to use less flexible conventional power plants as backup.⁴ As short-term weather forecasts and thus short-term output predictability improve the more critical variable for the utilisation of renewable energies and especially wind power the availability of longer-term capacity reserve. Good weather and thus wind output predictions allow wind to reduce exposure to the short-term (expensive) balancing market to a minimum, but longer-term capacity investments will still be needed for periods of generally calm winds. Capacity reserves are called upon between hours and days in advance. Thus, they operate in effect through conventional markets and part-loading is not normally an issue. Various options for this will be examined in more detail later in this chapter.

Wind power aggregation, grid operations and interconnection

The previous section has outlined the technical principles of providing certain ancillary services such as operational or capacity reserve to the grid. It is now aimed to give a managerial perspective on how this is operated in practice.

Liberalisation of electricity markets has resulted in a fragmentation of transactions. Traditionally, in many markets in IEA countries, either a publicly-owned organisation or a private monopoly had a licence to generate, transmit and sell electricity in a specified area. Today, a variety of market designs have evolved and financial markets for futures and options have been created alongside the

4. However, Dale et al. (2003) highlight that reserves still contribute useful energy to the system. With a conservative estimate of 10% for the reduced efficiency and a 20% load factor for wind power, they argue that emission savings from wind will be reduced by a little over 1%. In their scenario, 20% of electricity in 2020 is produced from wind power; so some 20% of fossil fuels are saved by applying wind.

physical electricity markets. In principle, physical balancing is a duty for the grid operator, but the precise market mechanism through which the associated financial transactions take place varies between countries.

When examining the impact of intermittency of wind on the grid, it firstly has to be noted that an analysis of individual wind turbines or wind farms in isolation does not capture the essence of the challenge posed. The fragmentation of the market might lead to the idea that each generator should provide individually for balancing reserve. However, this will not necessarily lead to a least-cost solution from a systems perspective. Thus, the objective of mitigating intermittency is not to provide a steady output from each renewable generator itself (*i.e.* individual wind turbines or -parks), but to equal demand and supply at minimised operation costs to the electricity system as a whole.

In this perspective, the grid plays an important role in mitigating the impact of intermittency. As discussed in the previous section, intermittent generators are not only likely to be geographically (*i.e.* north - south, up-hill - near-coast) dispersed but also technologically (wind, PV, ocean), which will smooth variations in output from the various sources as they are all connected to the same grid. This is a simple statistical phenomenon and the bigger the integrated grid (for example beyond national borders), the more pronounced this effect becomes. It is a general principle in electrical engineering that the larger a system becomes, the less reserve capacity it needs. Demand variations between individual consumers are mitigated by the grid interconnection in exactly the same way. Figuratively, just like consumers average out each other (in electricity demand), individual wind farms average out each other, too (in electricity supply). By way of an example, the peak load demand of an individual house can be over 15 times higher than the average load. In contrast, on the UK grid as a whole, peak demand is about 1.5 times higher than average demand.

In summary, the size of swings in output from wind farms and the volatility of average output are significantly reduced through geographical aggregation. Figure 3 below shows a typical situation for a (hypothetical) 1000MW wind farm in one place and having 1000MW of wind geographically dispersed but interconnected in the same grid. The size and volatility of output fluctuations is significantly reduced in the latter case.

Figure 3: The smoothing effects of geographical dispersion of a single wind farm and distributed wind farms, both rated at 1000MW (Mott MacDonald 2003:8)

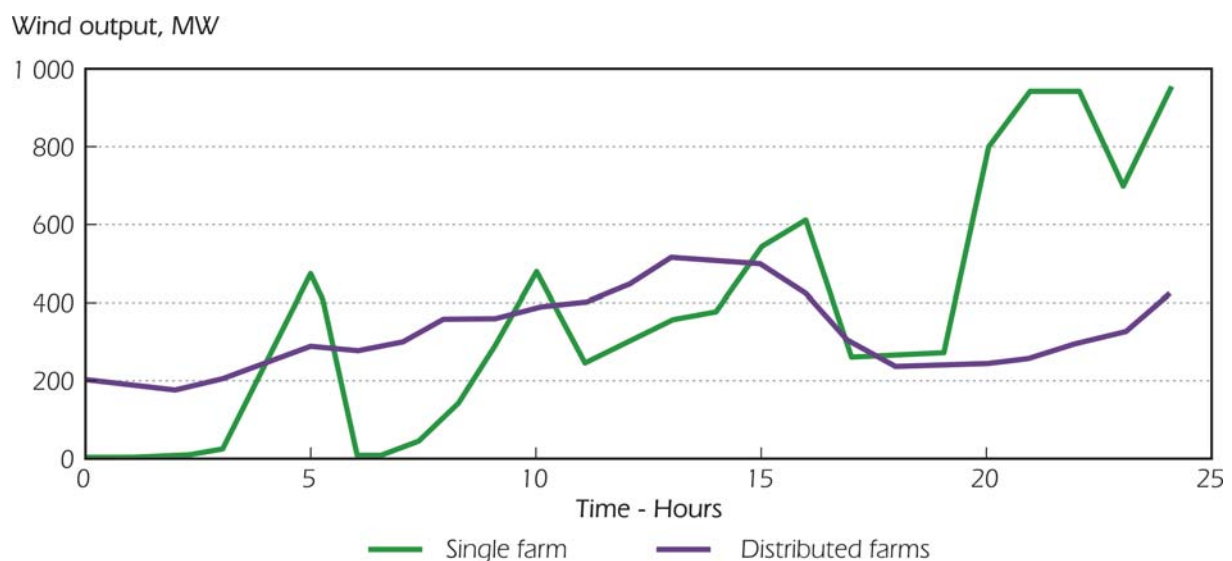
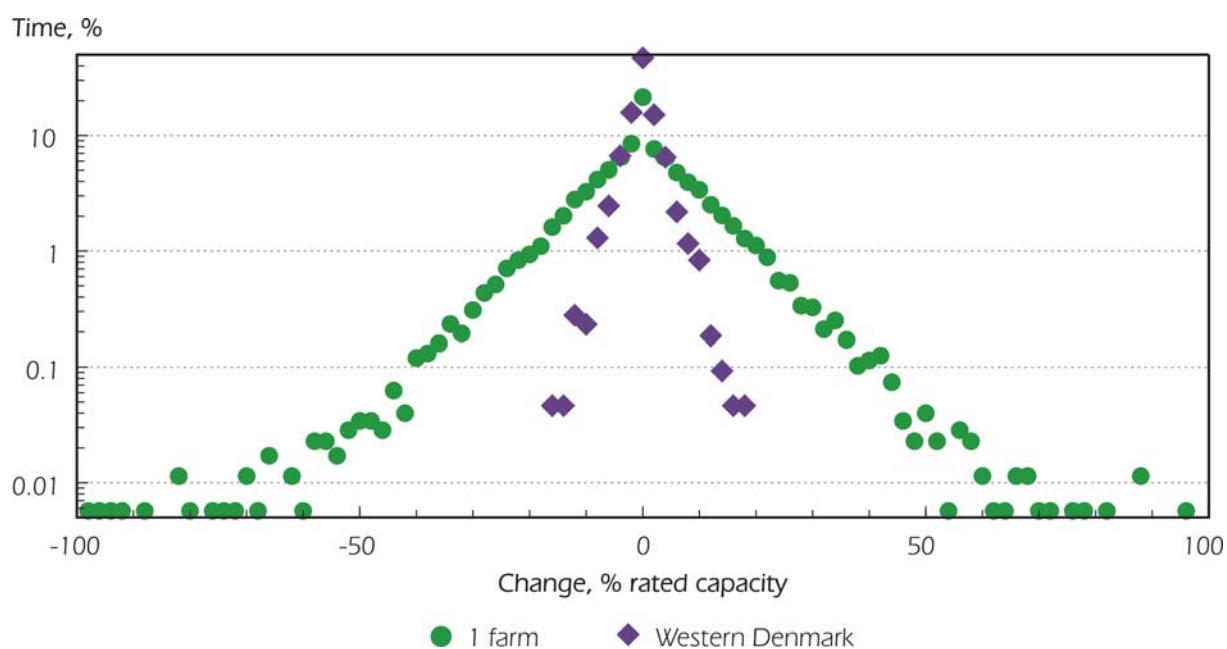


Figure 4 below shows real experience from wind farm operations in Western Denmark, comparing the variation in output from one hour to the next of one 5MW wind farm with the overall wind fluctuation on the Danish grid. This is a key variable for grid operators who often analyse variables in terms of their forecasted deviation from the present level. The horizontal axis shows the change in output after one hour as a share of the total installed capacity. The vertical axis gives the frequency of occurrence on a log-scale. In this case, the maximum one-hourly power swing from the wind farms installed in Western Denmark was 18% of installed capacity, and for almost 50% of the time it was less than 2% of installed capacity (Mott MacDonald 2003:8).

Figure 4: The smoothing effects of geographical dispersion on output variations (Mott MacDonald 2003:9)

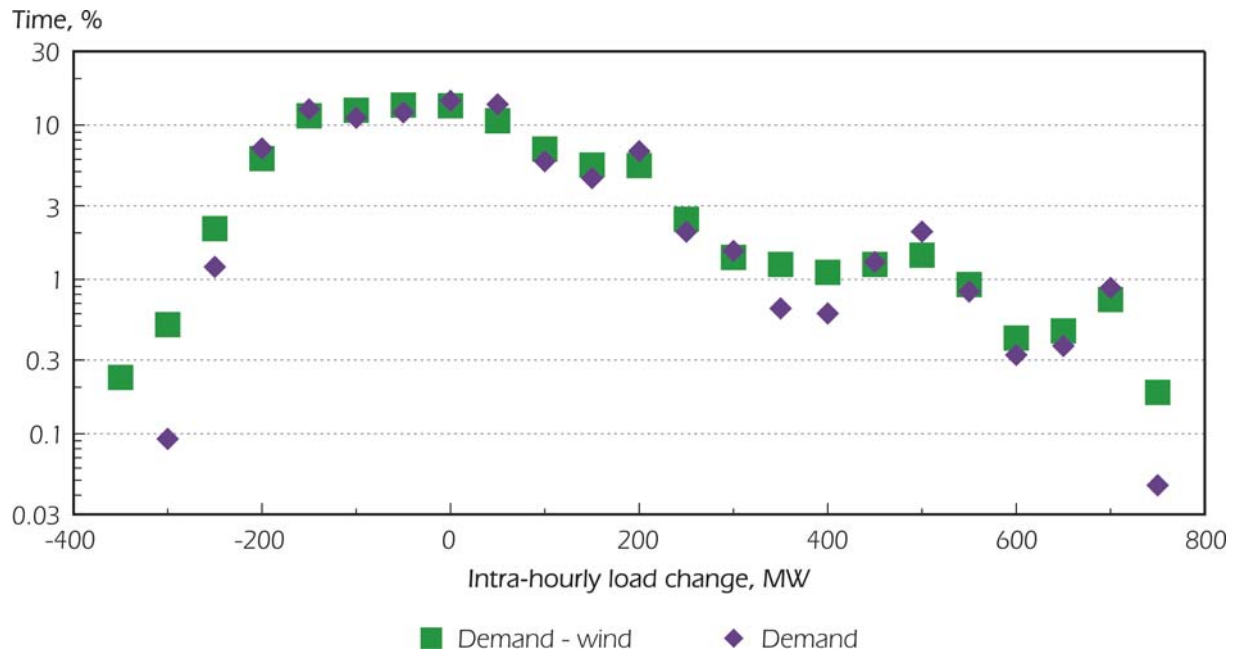


Finally, figure 5 shows the distribution of intra-hourly load (demand) changes in Western Denmark with and without a 20% wind share in electricity production (conceptualising wind output as negative load). The horizontal axis shows the change in demand (in MW) from one hour to the next, while the vertical axis shows the frequency of occurrence of each event. Again, the most frequent event seen on the system is no or little change in output (the area around '0' on the horizontal axis) between one hour and the next, irrespective of whether wind was present on the system or not.

From a grid management point of view, wind energy is a further variable impacting on overall system variability, but, just like demand, it fluctuates statistically random and thus can or cannot correlate with movements of other variables. This correlated movement might not be by the same amount in all cases, but it underlines once more, that the objective should not be to 'level' out fluctuations from every single wind turbine but to balance demand and supply in an appropriate area. Some further observations from Milborrow (2004b:5-6) in this respect, taken from studies on the German and Danish grid, are presented below.

- "The maximum hourly swing in output power from distributed wind rarely, if ever, exceeds 20% of the installed capacity of the wind plant. The standard deviation of the hourly swings is 3%. This information is important in the context of assessing the needs for additional reserves.
- The maximum measured change in output per minute from 2400 MW of wind in western Denmark is about 6 MW."

Figure 5: Intra-hourly load changes in Western Denmark, with and without 20% wind (Milborrow 2004b:7)



Consequently, it can be concluded that the interconnection into a common grid of intermittent renewables can significantly reduce the size and volatility of aggregate output swings that can occur due to weather conditions. It also makes use of the fact that both supply and demand exhibit a constant fluctuation and that it is thus not important to ensure steady supply of every single generator. The grid operator seems best placed to execute the physical balancing as all demand and supply information come together in real-time at this level. However, the exact market design to organise these 'balancing markets' is still an ongoing discussion in the electricity market regulation literature and will not be covered in depth here. The next paragraph will now discuss wind forecasting and modelling techniques that can further contribute to managing wind intermittency.

Weather forecasts and gate-closure times

From a grid management point of view, changes in electricity production are typically observed over short time-intervals (minutes, half-hourly or hourly intervals). Thus, for example, if current wind energy production runs at 2000MW, the question a system operator might ask is what will be the output in one hour? On the basis of weather forecasts and modelling results, the likely output is calculated and the operational reserve is planned accordingly.

The interest in wind forecasting has been growing over recent years along with the recognition of technical implications of higher penetrations of wind power. For wind penetrations of below around

5%, wind forecasting is generally believed as not necessary, since "deviations in wind output fail to show up in the ebb and flow of daily operation with [such] small grid penetrations" (Milborrow 2003:37).⁵ As wind penetration rises, wind forecasting increasingly adds value to wind power.

For example, the German balancing market is divided into four zones (operated by E.On Grid, RWE, Vattenfall and EnBW respectively), all of which use a forecasting tool called Wind Power Management System (WPMS), which has been developed by the German Institut für Solare Energieversorgungstechnik (ISET). This system reaches a prediction margin of error averaging 9% in day-ahead forecasting, 8% for eight hours ahead, and only 2% for one hour ahead (Knight 2003). However, some forecasting errors are expressed in terms of rated power, while others express this in terms of deviation from actual electricity produced. Thus, Holtinnen (2004:40) states that "for the Nordpool electricity market [...] the mean absolute error of wind production is 8-9% of installed capacity" which, if expressed in terms of the amount of energy produced converts to "38% of the yearly wind power production". In summary, there does not appear to be a sizable difference in outcome between the Scandinavian and the German system but methodologies do differ. For comparison, prediction errors of consumption are generally in the region of 1-5%.

Electricity generation from wind turbines will always vary with weather conditions but the more precise the forecasting and modelling becomes, the smaller will be the error margin in forecasting this variability and thus the lower the requirements can become for operational reserves and balancing energy. This is reflected in figure 6 below, which contrasts the gap between simple "persistence forecasting" and "perfect forecasting" and the impact on required operational reserve. Persistence forecasting assumes constant power output for one hour ahead, i.e. no change in power output over the next hour.

Research programmes that focus on improving wind forecasting and modeling techniques are ongoing in Europe and the USA. The German Institut für Solare Energieversorgungstechnik (ISET), together with the UK meteorological office and the consultancy IT Power, recently completed part of an EU research project⁶ to adapt and improve wind power prediction tools to market-based electricity trading systems. Further EU research investigates enhanced methods for forecasting, modeling and integrating wind power in liberalised markets.⁷

In summary, a sizable margin of error in weather forecasts can still exist and the longer the timeframe over which output has to be predicted, the higher the resultant error. This becomes important when actual markets for balancing capacity are considered. While the UK has a 'gate-closure time' of currently one hour (between final declaration of capacity and actual use of it), many IEA countries have gate-closure times between 12 and 36 hours in advance. These times have often developed out of historic structures and in many cases have no technological and economic background in the current system. Shorter times do not necessarily have to entail extra economic costs and there is a trade-off between reduced gate-closure times and thus better forecasts and the increased need for flexible operational reserve and thus potentially higher costs. Still, more investigation on the exact costs and benefits of this trade-off could reveal whether gate-closure times can be shortened in

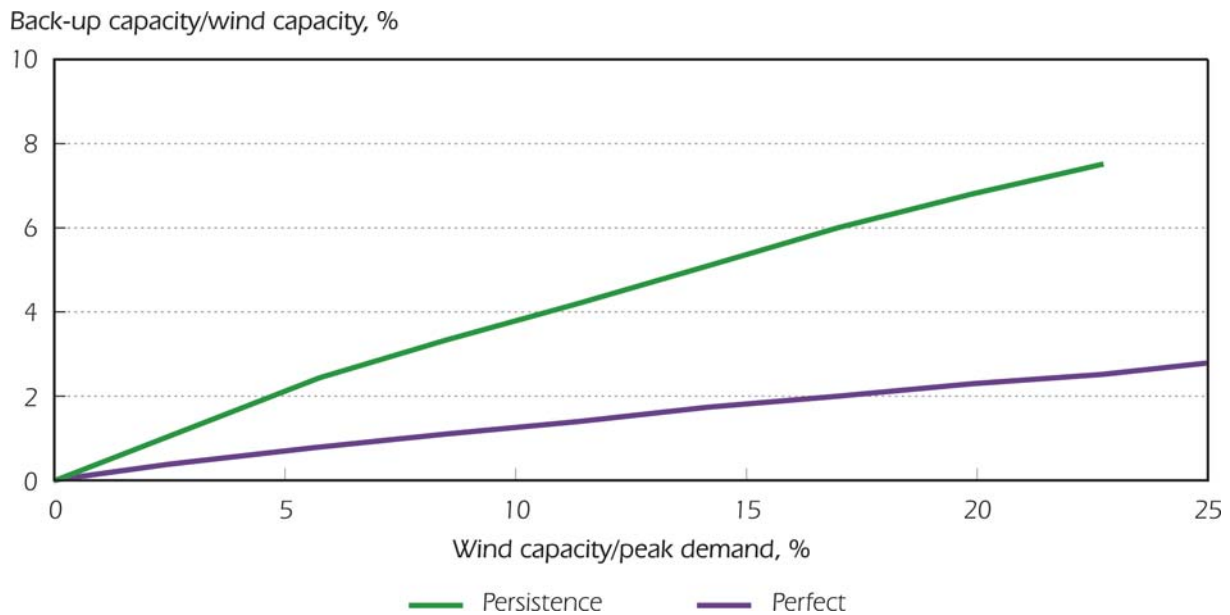
5. 5% as a level of wind penetration is here given as indicative. This may differ depending on the natural conditions of each individual region or country. As an example, the French TSO RTE (Réseau de Transport d'Électricité) estimates that a level of wind penetration of 3% could be met without increased wind forecasting.

6. For more information see the website www.dispower.org.

7. See for example the projects ANEMOS, HONEYMOON and WILMAR (<http://anemos.cma.fr/>, <http://www.ucc.ie/serg/honeymoon/> and <http://www.wilmar.risoe.dk/>)

respective national or international markets. With the increased use of communication technology as a result of evolving market structures, the information flow is already improving in many markets and might facilitate the reduction of gate closure times further. Yet, even with reduced gate-closure times, liquidity in most electricity markets is highest in the day-ahead trades, while activity in short-term energy trades on the spot market for one- or two hour-ahead contracts is typically low. Thus, some of the benefits from reduced gate-closure times might be mitigated by reduced trading opportunities in the short-term markets in many IEA member countries. Further considerations on the market integration of wind power can be found in appendix 9 to IEA (2005) and Neuhoff (2005).

Figure 6: Reducing added back-up for wind



Source: Milligan/NREL cited in Milborrow 2003:37.

In summary, Milborrow (2003:37) notes: "The bottom line value of a prediction model is the reduction it is likely to achieve in the extra costs, either of additional reserve or balancing market charges. [...] If these costs can be halved, as researchers claim, then the specific costs of adding an intermittent source of energy to the system such as wind come down accordingly." However, it has to be added that much the value of any improved forecasting also depends on the flexibility of the electricity system in which an intermittent generator is embedded. Better short-term prediction will only translate into reduced costs if the enough flexible technologies, possibly interconnected from another country, are available.

The value of wind forecasting will increase as wind energy reaches a higher penetration in markets, for example moving into the 10%-20% market share region. Hence, improved weather forecasts and output models are frequently cited in the literature as a key research priority to improve predictability of wind output.

Another aspect that is worth considering in this respect is that individual wind turbines generally have a very high technical availability (>97.5%) when compared to traditional power plants. Also, this availability is for one turbine, so any amount of significant wind power in an electricity system would never see all (hundreds or thousands of) turbines down at the same time. Availability in the

context of wind means being able to produce electricity when the wind is actually blowing. This would correspond to traditional power plants being able to produce when the fuel is available. The 'capacity factor' of wind farms is usually low (25-40% - depending on location) because the wind speed is variable and conventional power plants have a capacity factor in the 85% region because fuel supply is normally reliably organised. However, it should be recognised that better wind forecasting can reduce the need for operational reserve to a necessary minimum because wind turbines do have very few unexpected outages and need less maintenance than traditional power plants. The reason for conventional power plant's capacity factors being around 85% rather than 100% is primarily due to scheduled and unexpected outages which can take up more time on average than for wind turbines.

One phenomenon that has not been explored in much detail in the literature are high-impact, low-frequency events like long periods of still weather. Statistically, these 'outlier events' are at the edge of the probability distributions and in a contribution by Sinden (2002), the longest continuous time of calm weather in a 21-year hourly wind data set from 13 different locations in England and Wales was 11 hours, incidentally over night at a time of low demand. For the Scandinavian countries, 3-year data (2000-2002) showed that the longest duration of calm (production below 1 % of capacity) for Denmark was 58 hours in 2002 and 35 hours in 2000. For Finland and Sweden it was 19 hours and for Norway 9 hours. For the combined wind power production of these four countries, there were no totally calm periods in the data (Nørgård et. al. 2004:27).

Clearly, it is important to improve our understanding of long-term weather records and output data from wind farms from a variety of locations to have a better understanding of the probability of these events occurring. This will not only improve calibration of forecasting models, but will also allow market expectations of the long-term need for reserve capacity to adjust. Yet, it is clear that even improved forecasting will not change the fact that the variable nature of wind inevitably entails phases where there is no wind available. This and the remaining uncertainty in wind forecasting calls for additional measures to manage intermittency. Thus, some possible options are addressed in the following section.

Options for managing intermittency

Up to now, it was outlined how the impact of intermittency on the electricity grid can be mitigated by grid integration, geographic and technical distribution of generators and improved weather forecasting techniques. These techniques especially allow for a higher predictability of likely wind output, reducing the unpredictability element in the natural fluctuation to a minimum. Nevertheless, the residual unpredictability and the general variability - including periods where there is no wind available - have to be addressed.

Thus, this section outlines the various options for managing intermittency. As described in the first part of this chapter, the principal tools for this are the operational and capacity reserve, responding to short- to medium-term and long-term variability respectively. As has been outlined above, the short-term volatility and unpredictability of wind can be minimised to an extent where it disappears in the general fluctuation of the system. A recent study in Germany confirmed that the extension of wind power to some 36GW in 2015 would not require the addition of new plants to provide operational reserve (Dena 2005). Similarly, the French grid operator RTE estimates that the short-term fluctuations of 10GW installed wind capacity would not exceed 100MW within 1 minute, a figure which can be absorbed within current dimensioning of reserves without problems

(Bué 2005). Thus, for the future grid integration of wind power, the provision of flexible capacity reserve will become one of the key variables, reflecting the fact that even large wind capacity numbers will face climatic conditions where there is no or little wind. As will be discussed in the section on the economies of wind power integration, this is also one of the most important cost items when considering the long-term integration of wind power into electricity grids.

From a policy point of view, it has to be analysed which are the least-cost options system-wide in each case and furthermore, whether market participants are facing the right incentive structure to exploit those opportunities. The list of options presented below should not be considered exhaustive nor should it be understood as an attempt to pre-empt any market decisions. It serves as a reference to the most-discussed resources at current available technology.

The six main options currently discussed are:

- power plants providing operational and capacity reserve;
- electricity storage;
- interconnection with other grid systems;
- distributed generation;
- demand-side response;
- curtailment of intermittent technology.

The principle behind all these options is the same - balancing demand and supply continuously both over long-term timeframes and, where necessary, backing up other capacity within very short lead times. It is likely that in future electricity markets no one option will provide all the balancing services and that a combination of the above-named will be operating in parallel. Choosing between these options, the trade-offs need to be spelt out clearly. Ideally, a market can be envisaged where all potential options can bid into and the least-cost solution for each point in time is thus selected.

Power plants providing operational and capacity reserve

This is the most frequently cited option in the literature and has often been used as a benchmark to calculate the extra costs of integrating intermittent generation into the system both over short- and long-term timeframes. Using power plants for balancing services is a well known and tested ancillary service in electricity systems. In today's grids, it is typically met by flexible plants with relatively short response times. Depending on national circumstances, these could be open-cycle gas turbines (OCGT) but also steam-fired power plants like coal and oil running at below full-capacity. Strbac et al. (2002) - which is discussed further in the section on costs of wind power integration - use OCGT as a benchmark in their methodology to determine the costs of operating reserve due to variations in renewable technologies.

A market for capacity reserves per se is not likely to open in many countries. They will expect to be operating similarly to peaking plants, but depending on the availability of natural resources for the renewable technologies used, can expect operating hours between about 4000 and 5000 hours a year. The costs for capacity reserves will be determined alongside the regular market development but are likely to show up in reduced capacity factors of conventional plants and a preference in technology choice for plants which provide increased flexibility in operation. The IEA (IEA 2004b) currently forecasts a bigger role for combined-cycle gas turbines (CCGT) in electricity supply, although coal-fired power stations will retain their dominant position globally. For the purpose of their study, Strbac et al. (2002) use CCGT as a benchmark to determine the costs of capacity reserves.

Overall, in terms of commercial availability, cost competitiveness and ease of system integration, power plants are the state of the art for providing the necessary ancillary services for intermittent wind generation in most countries and are certainly the most tried and time-tested from the point of view of the system operator.

Storage

Hydro storage facilities, whether in the form of pumped-hydro or hydro reservoirs, have played a key role in many countries in providing several grid balancing services. Their advantages are the potential for large-scale electricity storage (> 1000MW capacity, depending on location), fast response times and relatively low operating costs. A fully loaded hydro facility can replace a conventional power station for several hours if needed. However, beyond hydro storage, there has been very little commercially available storage technology that operates on today's electricity grids. The main reason is that large-scale grid integration replaces to a certain extent the function of storage, as discussed in the previous sections and that other storage technologies are as yet not cost competitive. Storage systems within the grid have to compete against other technologies for the operational reserve services they could provide, and there is no a priori advantage to storage systems over generators for example. Only hydro-storage systems have a long history of utilisation and are thus well-established in today's markets.

Certain storage systems such as flywheels and certain battery types could become viable to provide specific support services for renewables in the frame of bridging very short-term output fluctuations (less than one minute) which also has the advantage of minimising the impact of power quality issues. One fundamental problem with storage is that where energy is converted from one type to another, conversion losses and thus inefficiencies are inevitably incurred, see table 3 below for details. This is true for batteries and hydrogen fuel cells (where electrical energy is converted to chemical energy storage) and flywheels (where electrical energy is converted to kinetic energy).

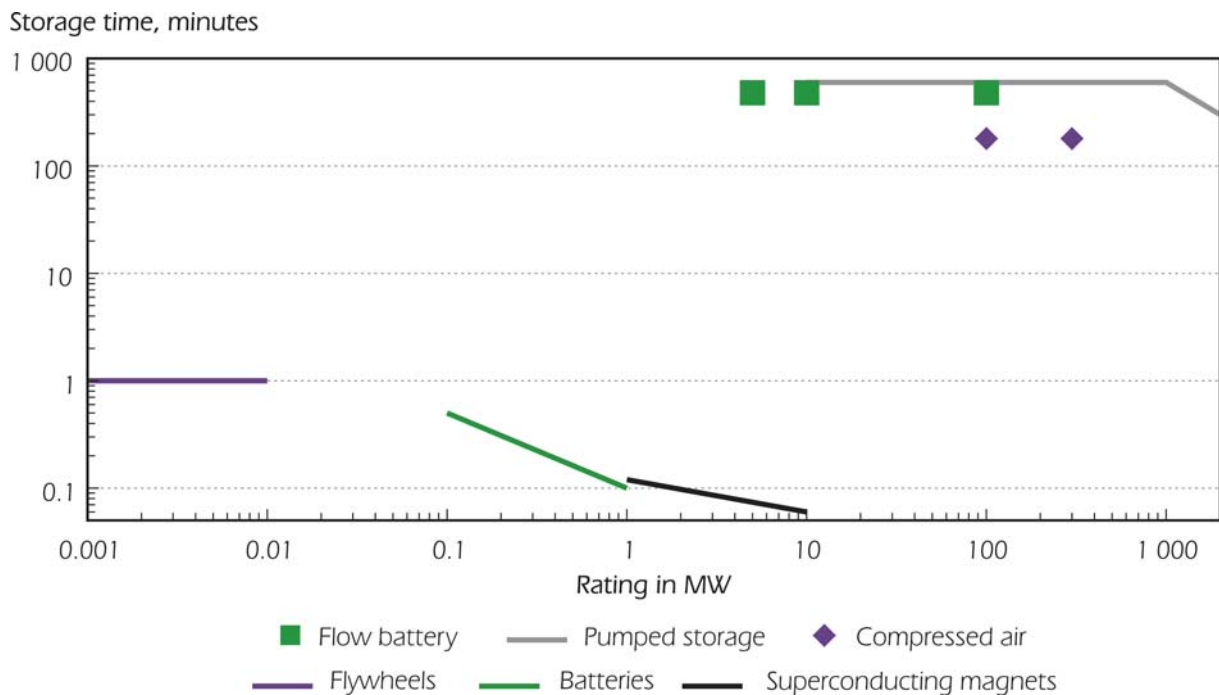
Table 3: Various storage technologies and typical technical performance

Storage technology	Typical round-trip efficiency (in %)	Typical capacity
Pumped-hydro station	~80	> 100 MW - > 1000 MW
Compressed air storage	~75	> 50 MW - > 100 MW
Flywheel	~90	> 1 kW - > 50 kW
Conventional batteries	~50 - ~90	> 1kW - > 10 MW
Flow battery	~70	~15MW
Hydrogen fuel cell	~40	> 50 kW - > 1 MW

Depending on available locations another viable form of storage is compressed air, which is stored in geologic structures under the ground and released when necessary. Typical places for such projects could include disused coal mines or salt domes. A number of projects have been developed in the USA and Europe for the purpose of 'peak shaving', whereby the potential energy is built up in periods when demand is low and released during hours of peak demand.

Batteries are typically operated on small-scale systems, and no commercially viable solution for large-scale battery storage has been demonstrated to the market yet. The UK company Innogy announced in 2001 the development of a 'flow-battery' labelled 'Regenesys', which was hoped to bridge this gap with a power rating of 15MW and storage capacity of 120MWh, but the project was cancelled by Innogy in 2003 for apparently technical reasons, although the exact circumstances were never fully disclosed. Still, batteries could play a role for intermittent renewables in smoothing short-term fluctuations, thus providing more stable energy in the intra-minute period. In the long-run, it is speculated whether hydrogen storage might become a viable option on different scales, however, currently high costs and relatively poor round-trip efficiency is preventing wider market penetration.

Figure 7: Time and power rating of various electricity storage options



Source: Milborrow 2001a.

Flywheels are a kinetic storage option - "electricity to be stored powers an electric motor which increases the speed of the flywheel, while electricity is recovered by running the motor as a generator which causes the flywheel to slow down." (Dell and Rand 2001:9) Again, this technology is of interest primarily as a short-term buffer to smooth local output fluctuations from a wind-farm or PV-array. It can remove the need for more expensive power electronics downstream to smooth such fluctuations and thus improve overall cost efficiency.

Figure 7 summarises the time- and power ratings of the various technologies. Overall, in the absence of major technological and cost break-throughs, storage in mature large scale power systems will only play a minor role in the short term, apart from hydro- and compressed air storage. Besides, technologies for bridging short-term power fluctuations such as flywheels or batteries may only gain importance at higher than current wind penetration levels. As mentioned previously, most IEA countries' existing operating reserves are sufficient to absorb current levels of fluctuation. However, the development of renewables and market liberalisation itself could act as powerful

incentives to intensify R&D efforts in this field. Experience from the Eltra system in Denmark suggests that spot prices can fall to zero or could even become negative in the future where there is a high penetration of intermittent renewables and furthermore combined-heat-and-power (CHP) plants. In other words, there are times of the day when the market offers to pay a storage-device operator to take up some electricity from the market. This can consequently be sold back to the market once prices return to positive again. Another example is differential pricing between base load and peak load which could be exploited by storage systems that charge during the cheap night-time period and release energy when demand is peaking and prices are high. As renewables penetration in the markets increases, the need for operational reserves become more important and could furthermore act as an incentive. Also, the full pricing of emissions of conventional reserve providing backup capacity would improve the relative economics of storage as an alternative.

Interconnection with other grids

As mentioned earlier, one reason why the western Danish grid can handle a high proportion of wind power very well is that it has good interconnectors with the Swedish, Norwegian and German grid and thus, for example, access to Norwegian hydro-power as reserve capacity. The Scandinavian 'Nord Pool' electricity market was established in 1996. One of the drivers for its establishment was the difference in generation mix, with Norway depending largely on hydropower, Sweden on a mix of hydropower and nuclear power, Denmark on thermal power plants and wind only emerging. 'Nord Pool' market participants trade power contracts for next-day physical delivery on a Spot Market, and on separate futures markets.

The benefit for a country such as Denmark, generating some 20% of its electricity from wind power, is apparent: Denmark can trade wind power on the spot market in times of excessive supply, and if this cannot be used at the time of production elsewhere in the market, it can be stored in hydropower storage facilities *i.e.* in Norway. In turn, Danish operators can purchase extra electricity on the 'Nord Pool' market at times of low wind generation.

The connection to the 'Nord Pool' market, together with the rather unique situation of strong interconnections to Germany, allows Denmark to balance the high penetration of wind power. Comparing Danish wind penetration levels to other countries such as Spain, where the system operator claims 17% of wind penetration to be the upper limit, is therefore to some extent misleading. However, it reflects (besides other factors) the importance of interconnections to other grids, as Spain is only poorly connected to its neighbours, as McGovern (2003) describes. A new Iberian pool ('MIBEL') will improve management of the strong interconnections between Spain and Portugal but physical transmission between Spain and France remains relatively weak for the moment.

However, the high concentration of wind power in the Northern Part of Germany and its proximity to the Danish grid with a similarly high share of wind capacity on the system can pose threats to systems despite good interconnection to the neighbouring countries. This is due to the fact that transmission grids have not been originally developed to accommodate increasingly large amounts of wind energy and associated cross-border trade. According to the Dutch system operator, this has led to a few events where transmission capacity between Germany and its Western neighbours in the Netherlands, Belgium and France was seriously congested and system stability was threatened. These events occurred either when wind output in both Germany and Denmark was high at times of low demand, thus exporting excess energy into neighbouring grids. Alternatively, at times of low output and high demand, additional energy was imported from France. This highlights not only the

need for further transmission grid development, including strengthening and upgrading existing lines, but also the fact that interconnection is only one - though clearly very important - measure in the portfolio of options to integrate wind power successfully. Failure to develop grids concomitantly to intermittent resources such as wind power is likely to threaten system stability.

Furthermore and critically, planning new grid capacity is a time-consuming process and building new transmission lines comes at additional costs. Initial capital outlays can add up to hundreds of million Euros invested and regular maintenance is required once these assets are installed. More importantly, planning procedures in many IEA countries can take between 3 and 10 years, which means grid extensions cannot be realised without significant lead times.

In general, interconnection of grids is frequently seen as an important step towards improved competition and full market liberalisation, for example in Europe and North America. Resources, both to power renewable energy sources and conventional power plants, are unevenly distributed and available across different power grids, thus limiting the options available on any one grid. Interconnection increases the number of available options and therefore provides significant value as lower cost balancing power stations can be accessed or even be shared. This allows for a more efficient utilisation of resources and can also contribute to system security.

Major interconnection plans are currently discussed, linking for example Norway and the Netherlands⁸ through a sub-sea High-Voltage DC (HVDC) cable. The major driver here is better utilisation of resources, gains from market competition and trade and increased security of supply. Norway holds significant resources of hydro power which it will be able to utilise more efficiently when linked in with the Dutch and thus the continental electricity grid. It also serves as a further reserve option for the Norwegian grid in case of hydro resource shortages. New technology such as HVDC will improve power flow and reduce losses and costs. Underground cabling is investigated as an alternative to overhead power lines on land as well to circumvent lengthy planning procedures, but this significantly adds to the costs (Dena 2005). The EU has a priority plan for interconnecting its member states' electricity grids.⁹

The IEA (IEA 2004b) forecasts that electricity markets in the OECD countries alone will need investments of \$1.8 trillion in transmission and distribution networks in the period up to 2030. This is merely to keep up with expected demand growth and to upgrade aging assets. A forward-looking policy should aim to integrate these investment needs with renewable energy related investments and thus create an integrated strategy to face future challenges in the transmission, distribution and interconnection field.

Distributed generation

IEA (2002:19) defines distributed generation (DG) as "... generating plant serving a customer on-site or providing support to a distribution network, connected to the grid at distribution-level voltages." DG can provide significant system benefits for local distribution companies by relieving congestion, reducing transmission losses and delivering ancillary services to the system. Thus, DG could provide

8. See announcement by Statnett <http://www.statnett.no/default.aspx?ChannelID=1169&DocumentID=11438>.

9. The EU priority plan for a Trans-European Energy Networks is outlined on the website of the Directorate General for Energy on <http://europa.eu.int/comm/energy/ten-e/en/index.html>

fast and longer-term reserve requirements to the grid on a regional level as an alternative to large-scale power plants. One of the most frequently cited DG options are combined-heat and power (CHP) plants, which produce heat much like a conventional boiler but also produce electricity at the same time, thus increasing the efficiency of fuel use. This is utilised in colder climates such as Scandinavia, for example, where electricity demand is higher in winter and load increases are typically greatest in the morning at the same time when the heat demand picks up.

However, as highlighted in IEA (2002), there currently exist a number of barriers to a wider integration of DG into electricity grids. One important area is information exchange, a topic that has already been highlighted earlier in connection with weather forecasting for wind farms. IEA (2002:98) notes: "If networks are managed in a decentralised way, for example with individual customers responding to the needs of the local network, they will require a greatly increased flow of information to ensure smooth operation of the system. The distribution utility of the future will need to be in a position to provide information, and to monitor and control its own system in a more sophisticated manner." Similar requirements could become important to operate a greater number of renewables such as wind farms in an efficient way. Thus in this area, DG and intermittency may have similar requirements for future grid operations and upgrades.

Demand Side Response (DSR)

In some ways, DSR has been the great enigma of electricity policy. The idea behind DSR is that electricity produced at different times of the day has different values, as can be witnessed by the price differential between base and peak load power on the wholesale market. If the marginal peak load price is higher than the value that a customer gets out of the services derived from the electricity delivered at peak times, he/she would be willing to modify demand if paid the peak price or slightly less instead. A grid operator is indifferent between paying a power producer to supply more output and paying the same amount to a customer to switch off his/her electric appliances instead, as both provide the identical balancing service. In principle, market mechanisms can be devised to capture such a market and DSR could be an important aspect of load management both to cope with peak demand and with intermittency. DSR makes the demand curve for electricity more elastic and thus sensitive to price changes which will reduce the need for reserves in an electricity market *ceteris paribus*.

In practice, however, contributions from DSR in many countries have so far been relatively small, with some exceptions such as Norway. It is however unclear, whether this is due to electricity users' marginal valuation of electricity being too high to stay on-line even at high prices, or whether there are transaction costs or informational barriers to access such a market. DeCarolis et al. (forthcoming) review some recent experience of DSR techniques. It is also proposed that participants in DSR use on-site distributed generation technologies to replace the supply from the grid but for such switching to become automatic electronic communication and an increased flow of information will be necessary. While households would be another attractive target for DSR, their electricity bill is often only a small fraction of total household spending which provides only a small incentive. However, aggregation or 'consolidation' service providers that represent a bundle of households at the wholesale market could explore this market niche. A recent action paper by Eltra (2004b), the Danish grid operator, has highlighted the potential of DSR in order to cope with large amounts of wind energy and CHP plant penetration and will be discussed in more detail in a further section below.

Curtailment of wind farms

Recently, with the expansion of wind farms offshore, curtailment of intermittent technologies has become a further option to cope with system variability (Gardner 2004). Large wind farms, with a significant number of megawatt-sized turbines can in principle provide the same ancillary services that conventional generators offer today. Switching off some wind turbines for operational reserve or running them at reduced output becomes a realistic option with modern large-scale wind farms. Furthermore, where transmission and distribution capacity is congested, curtailment of wind farms is an option to ensure system stability. Thus, as in the case of Northern Germany, at times of increased congestion on the grids, wind farm operators have switched off their turbines for short periods of time to ensure system stability. Associated requirements are emerging in some Grid Code documents for wind generation which Transmission System Operators are developing or publishing at the moment. Wind turbine manufacturers are also investing in associated technology as part of their business. Additionally, modern control technology of wind turbines can furthermore smooth sudden bursts and even out short-term fluctuations. Reducing output from a source that produces at almost zero marginal costs might sound unattractive. But the flexibility offered by wind turbines can be very valuable for an electricity system, as the alternative of shutting down or part-loading coal and combined cycle gas turbines implies higher energy and maintenance costs for subsequently heating them up. Therefore, tariff systems or contractual arrangements are required to ensure that wind turbine owners benefit from the system savings they can provide with a flexible operation of their turbines.

Summary of options

The resultant mix of options is likely to be different between different national grids. For example, where hydro power is available for balancing services, this is likely to be the predominant choice since it has been proven as very flexible at low prices for these services. Grids with a high proportion of gas-fired power plants might be more reliant on this technology again for its desirable characteristics. Greater interconnection between grids would allow for a greater availability of least-cost options on a wider geographic scale while mitigating the impact of intermittency further. On the other hand, this will probably require increased long-distance transportation of electricity with associated transmission losses and investment requirements for grid upgrades.

In any case, when choosing between the different options the trade-offs have to be visible in the market for it to deliver a least-cost solution. However, this is often not the case. For example, many grids do not 'see' distributed generation as dispatchable and thus cannot extract the potential benefits from this option. Without differential pricing at different times of the day, storage systems and demand side responses will not be economical. To upgrade grids and increase the interconnection between them, large-scale investments are often required but at current there is often no clear regulatory incentive for those who benefit from these investments to meet a share of the costs.

Depending on the strategy chosen and the options available, the costs will vary. In the following section, a number of studies are presented that have analysed the cost implications of integrating intermittent renewables - in most cases wind - into the electricity grid. They provide a range of estimates and actual numbers, and it should be remembered that most of them are country or system specific, reflecting technological options and market structure.

Costs of wind power integration

This section summarises a number of studies from Europe and the USA that attempted to quantify the additional system costs that wind power might impose on electricity systems. Assessing the added costs of integrating renewables into electricity grids involves four main parameters: Balancing, operational reserve, capacity reserve and extension of transmission and distribution lines. As has been summarised in the previous sections, grid operators estimate that the need for additional operating reserve is likely to be limited relative to the other two items. As wind power expands, the issues of additional capacity reserve and new transmission and distribution lines will grow in importance. The studies presented below use slightly different methodologies to assess the various cost items. Thus, while some aim to quantify all of the above-listed system integration costs, others focus specifically on the operating and capacity reserves. Also, it has to be borne in mind that the precise numbers are country-specific and there is no one cost figure that is universally applicable. In this sense, the studies below present an overview of different country experiences and expectations on the costs of system integration of renewables. A further discussion of the costs of grid integration of wind power can be found in appendix 9 to IEA (2005).

Strbac et al. (2002) were commissioned by the UK Department of Trade and Industry (DTI) to carry out a study 'Quantifying the System Costs of Additional Renewables' to the UK electricity grid in 2020 (also known as the SCAR report). A variety of scenarios, using different combinations of technologies were considered, and OCGT and CCGT power plants were used as benchmarks to quantify the additional system costs of operational and capacity reserve respectively. A comprehensive methodology was developed to assess all relevant aspects of system adaptation due to renewables. This included the reinforcement and management of the transmission system, the impact on transmission losses, the reinforcement and management of the distribution networks and balancing energy generation and demand. This methodology could well serve as a model for other countries to quantify their own system costs of integrating renewables.

In a scenario using a mix of biomass and wind, it was found that the total additional system costs per year for a 20% renewables share were €205m (£143m) in 2020, translating into total additional system costs of €4.9 per MWh of renewable electricity compared to current wholesale electricity prices in the UK of about €47 (£32). The highest additional system costs were found for a scenario where the renewables share would come predominantly from wind, mostly located in Scotland and off-shore, far away from load centres. Here the per annum additional system costs would be €570m (£398m) in 2020, translating into total additional system costs of approximately €14 per MWh of renewable electricity, in this case almost entirely from wind. An extensive sensitivity analysis of a variety of parameters can be found in the study. As expected, costs for upgrades in the transmission and distribution system were highest in the scenario with a high share of renewables far away from load centres, contributing about one quarter of the additional costs. In all scenarios, costs for operational and capacity reserves dominated, taking a share between 67% and 100% of the total costs. In the break down between operational and capacity reserve, costs for the latter dominated in all scenarios, typically at a ration of 2/3 to 1/3.

A second comprehensive study, which examined reserve as well as transmission and distribution requirements is presented in Auer (et al. 2004) from the "GreenNet" research project.¹⁰ In reviewing

10. For further information see www.greennet.at.

international studies (incl. Strbac et al. 2002) and modeling their results in a number of European electricity markets, they establish a cost range for system integration costs specifically for wind power at different levels of market penetration and for different climatic conditions. For a 20% market share of wind power, they establish a cost range for operational and capacity reserves between €4.5 and €6, while transmission and distribution upgrades are modeled to lie between €2.5 and €3. Thus, total costs range from €7 to €9 at that level of market penetration.

Table 4 below summarises figures from different studies focusing on the operational and capacity reserve costs of wind in the UK, both in terms of absolute costs per annum and per MWh of wind generation. Note that this is different from the more comprehensive methodology in Strbac et al. (2002). However, as different studies analysed different aspects of wind integration a common basis on the assessment of these costs can be established in this way.

Table 4: Costs of extra balancing wind in the UK

Wind penetration in % of total capacity				
	5.3	7.6	10	14.2
Total cost in €million per annum				
Lower estimate	26	44	66	120
Median estimate	29	54	80	143
Upper estimate	41	79	119	215
Cost in € per MWh of wind electricity				
Lower estimate	1.3	1.6	1.8	2.1
Median estimate	1.4	2.0	2.3	2.4
Upper estimate	2.1	2.9	3.4	3.7

Source: Mott MacDonald 2004:34; exchange rate used: 1£=1.43€.

The lower boundary costs were taken from an energy review by the cabinet office of the prime minister of the UK, conducted in 2001/2002 (PIU 2002). The Upper boundary represents figures calculated by the UK grid operator (National Grid Company) which are based on somewhat more conservative estimates of market prices for balancing services (NGC 2001). Finally, the middle estimates are again from Strbac et al. (2002). It should be noted that these figures, even in the most pessimistic case, represent about 8% of current wholesale market prices in the UK (€47/MWh or £32/MWh), noting that these include only balancing costs.

For Western Denmark, the Transmission System Operator (TSO) Eltra (2004a) reports that for the 3,368 GWh of wind power that they were mandated to purchase in 2003, the total balancing costs were €8.7m (65m DKK). This corresponds to about €2.6 per MWh of wind energy.

For Germany, E.ON reports 6250 MW of wind power on its grid in 2003 and costs of more than €100m (Winter 2004). It is not clear what these costs include. With wind energy production of 8.5 TWh in 2003, €100m corresponds to approximately 11.7€ per MWh of wind energy.

The large differences in reported balancing costs between the German and Danish grid appear striking at first glance. However, they might point to the fact that reported market prices for balancing services are not always equal to actual economic costs incurred or alternatively that a higher proportion or absolute quantity of wind power is more expensive to balance within a given grid.

Smith et al. (2004) summarise a total of eight studies from US utilities and research laboratories on the additional operational and capacity reserve costs of wind power. The studies had slightly different scopes depending on the precise system under investigation, and calculations were made for wind penetration levels ranging from 3.5% to 29%. Total additional system costs ranged between €1.13 per MWh (1.47\$/MWh)¹¹ and €4.22 per MWh (5.50\$/MWh) amounting to between 2 and 15% of current US average electricity prices. The authors note that "It is now clear that, even at moderate wind penetrations, the need for additional generation to compensate for wind variations is substantially less than one-for-one and is generally small relative to the size of the wind plant." (Smith et al. 2003:7) However, they also point to important areas of future research, among others a better understanding of how a market for ancillary services could operate. Also, improving available wind forecasts and the models operated by grid operators that implement the resultant data are identified as a priority area for improving the cost performance of wind power.

Table 5 (adapted from IEA 2005:214) presents an overview of the different costs for system integration of wind power that have been presented above. It has to be borne in mind that these numbers are highly dependent on the specific circumstances in each region, including geographical and climatic conditions, the state of existing electricity grids and available technologies and the precise market design. IEA's (2005) best estimate to date covers a range of between €5 and €15 for the total system integration costs of wind at 20-30% market penetration.

Table 5: Experienced and modeled costs of integrating wind power, euro per MWh of wind power*

	E.ON Netz**	Eltra	Smith et al. (2004)	Strbac et al. (2002)***	Auer (2004)***
Balancing	11.7	2.6	1.13 - 4.22	3.3	1.5-2
Operational reserves				6.7	3-4
Capacity reserves				4	2.5-3
Transmission & distribution					

*For comparison with other technologies it must be taken into account that all technologies require integration costs. ** E.ON Netz (2004): 8.5 TWh of wind power in 2003 and costs of more than 100 mil. Euro. It is not clear what these costs include. *** At 20% wind power shares of consumption.

In summary, from the findings presented above, a number of general conclusions can be drawn:

- Firstly, all the studies published have found that the integration of wind power at the levels considered thus far does not need one-for-one backup capacity. Electricity grids already operate with high levels of reserve due to the conventional mix of power plants connected, thus absorbing the incrementally added variability due to wind power thus far.

11. 1\$=0.77€

- Secondly, the survey on costs also shows that large differences exist between countries. This is on the one hand due to different climatic and geographic conditions, the technology mix, the state of the grid and levels of wind power market penetration in each country. On the other hand, markets and incentives to manage intermittency in an efficient manner do not exist in all cases, thus the true economic costs are not always revealed in the reported prices.
- Thirdly, the cost ranges presented in table 5 are mostly for electricity markets where wind power has reached a share of 20% or more. Currently, only the Danish and Northern German region exhibit such a level of market penetration in practice.
- The range of these costs suggests that gains can be achieved by pushing costs to the lower end of this range through, for example, careful and efficient market design and optimised location of new wind plants.

Markets for managing intermittency

Having reviewed a number of studies that aimed to provide cost estimates of integrating wind into the electricity grid, it will now be asked, how markets are actually set up to manage this task. Taking one step back from the studies presented in the last section, two factors still have to be kept in mind. Firstly, costs will always differ between countries and regions due to different levels of market share of wind power, the availability of renewable resources and options to mitigate the effect of intermittency. Secondly, market regulation varies among IEA countries so prices might not always be reflective of the actual economic costs imposed. In the following some examples are presented of how countries have modified their markets to allow for a better management of renewables. This should in no way be seen as comprehensive, rather it is sought to present a range of contemporary issues of how market rules are adapted to better integrate intermittent renewables.

DSR in the United Kingdom and Scandinavia

Both the Scandinavian ('Nord Pool') and UK (NETA) market operate a short-term balancing market to make up for differences between actual and scheduled production, thus establishing an important prerequisite institution for DSR to operate. While most of the short-term balancing is still provided by generators regulating up and down their capacity, there have been market actors that have bid into these markets based on their demand, offering to lower or increase their electricity consumption at a specific time according to the price signals in the market.

Ofgem (2004), the UK electricity market regulator, recently quoted an example from a specific day, 28 January 2004, where during a peak winter period DSR provided about 1 GW of capacity (reduced demand), which represented about 2% of total demand at the time.

Eltra (2004b), the Danish grid operator, notes in a recent 'action plan' that DSR was a key to improved market functioning and better integration of large amounts of wind power onto the system. DSR is also appreciated for reducing the scope for the abuse of market power in the general electricity market, since the demand curve becomes more elastic and thus more responsive to price increases. A strategic generator would therefore need to withhold more output and lose more revenue to achieve the same price increase and would consequently be less inclined to do so. Moreover, from a system security point of view, DSR provides 'capacity' to cope with periods of low supply and/or high demand (and principally vice-versa). Eltra has proposed an action plan with a total of 22 projects to - among others - assess the viability of DSR, improve the information among likely participants, trial new business models and test new electricity meters to improve the share of DSR on the system. Most of these projects will be finished by 2008-2010 and it will be clearer by then what role DSR can play on the Danish grid.

Norway established a new power reserve market on 1 November 2000. Both generators and consumers can bid into this market and Statnett, the Norwegian grid operator, reports significant demand-side participation, mainly by large customers in the paper and steel industry. Participation is invited by a bidding system for a fixed balancing product. The minimum size of balancing power is 25MW, which must be available for DSR within 15 minutes of notification and last for at least one hour without interruption. Participants must be prepared to offer this service for at least 10 hours per week (Nilssen and Walther 2001). At the second bidding round in 2001, a total of 2967 MW of balancing reserve were offered to the grid operator through 80 offers of which 23 were accepted for a total of 944MW.

United States balancing market

Utilities in the northwest of the United States who want to add wind power to their portfolio but do not want to get involved in the day-to-day balancing of intermittency now have a new offer to choose from. To make utilities more acquainted with intermittent renewables and generally raise the profile of wind energy, the Bonneville Power Administration (BPA) recently started offering a new business service. Thanks to its vast 7000MW hydropower network, the BPA offers to 'soak up' any amount of intermittent renewable output and re-sell it as firm output from its hydropower network one week later (O'Bryant 2003).

Utilities will first have to secure a power-purchase agreement directly with the wind farm operator, organise for transmission through the BPA network and schedule the wind capacity. At a charge of €3.45 per MWh (\$4.50/MWh), the BPA then absorbs this wind energy and delivers an equivalent amount as firm capacity one week later.

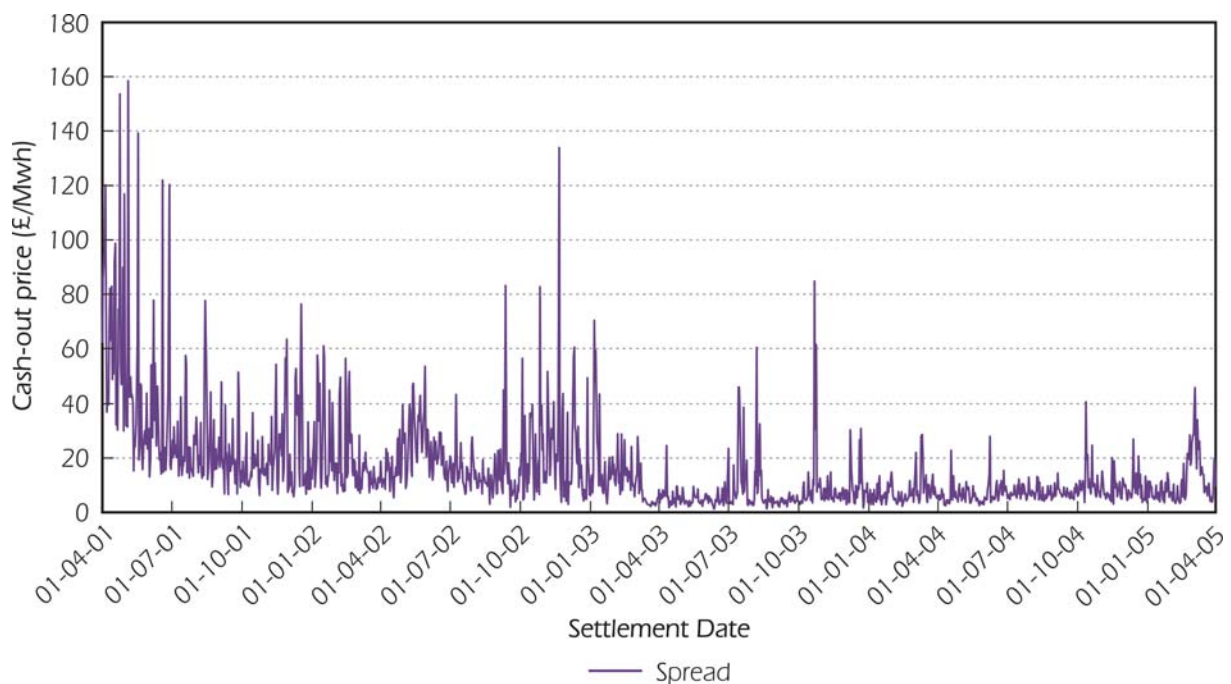
While this price is not necessarily cost reflective of the actual costs that BPA incurs, it could act to lower information barriers and increase interest in wind energy, taking out the perceived high risk that intermittency otherwise might inflict. It might also spur other operators to offer similar services at lower prices thus inducing some competition for the lowest cost way of managing intermittency. However, balancing services need to be supplied within a local region defined by potential transmission constraints, and are therefore typically only offered by a limited number of generators. Therefore, unless new storage technology offers low-cost small-scale storage options or balancing zones are enlarged, it is possible that competition for the provision of balancing services will stay limited and will require continued market power monitoring to achieve efficient prices and investment incentives.

United Kingdom NETA system

Following the start of the New Electricity Trading Arrangements (NETA) in the UK on 27 March 2001, one commentator observed that "The most profitable way of operating a wind farm so far has been to turn it off". The rules that were implemented in this new market changed the operating conditions for wind farms from one day to the next in such a way that they ran into serious trouble without any change in the underlying wind characteristics or physical operating conditions. Moreover, given the modest amounts of wind that were connected to the UK grid at that time, the real additional costs that were imposed by wind on the system were negligible compared to the amount that was actually charged under NETA. Under NETA, operators had to engage into supply contracts for half-hourly intervals at least 3.5 hours in advance on the spot market. Should the wind conditions change subsequently, each individual wind farm operator had to trade surplus or deficiency in a system balancing market, where prices differ from the spot market.

The purpose of these imbalance prices is to provide a commercial incentive to all participants to honor their positions. If a generator has a shortfall in generation, it must pay for that shortfall at the so-called System Buy Price (SBP). If a generator produces more energy, then it is paid for this excess at the so-called System Sell Price (SSP). In a working paper for the UK cabinet office, Milborrow (2001b) notes that NETA imposed additional costs of between €3.6 per MWh (£2.5/MWh) to €5.7 per MWh (£4/MWh) for about 500MW of wind power that were connected to the system at the time, about 1% of total capacity in the UK. In contrast, on the basis of the Danish experience with wind power, calculating the real technical system costs of balancing even 10% of wind would yield an imbalance price of only €2.1 per MWh (£1.5/MWh). Naturally, there were differences in the options available between the two grids, but this was insufficient to explain the large price difference actually witnessed.

Figure 8: Spread between System Sell Prices (SSP) and System Buy Prices (SBP) on the United Kingdom NETA markets since April 2001



Source: Elexon Ltd, London.

This was partly due to teething problems of NETA as, especially in the first few trading months, the spread between SSP and SBP in the balancing market was relatively large and relatively volatile in general (see figure 8 above). Especially the SBP had very high spikes so the penalty for being short in the market could climb above €140 per MWh (£100/MWh) for brief periods. This has narrowed significantly as market participants gained experience. Nevertheless, structural improvements were suggested that would recognise the specific technical situation of intermittent renewables without distorting the market or raising costs. After some lobbying by renewable energy groups and also combined-heat-and-power (CHP) plant operators, some changes were implemented to the market rules.

As noted initially, the gate-closure time, *i.e.* the time between notification and despatch was set at 3.5 hours when NETA was launched. This had a particularly negative impact on intermittent renewable generators since supply forecasts over this timeframe had a substantial margin of error.

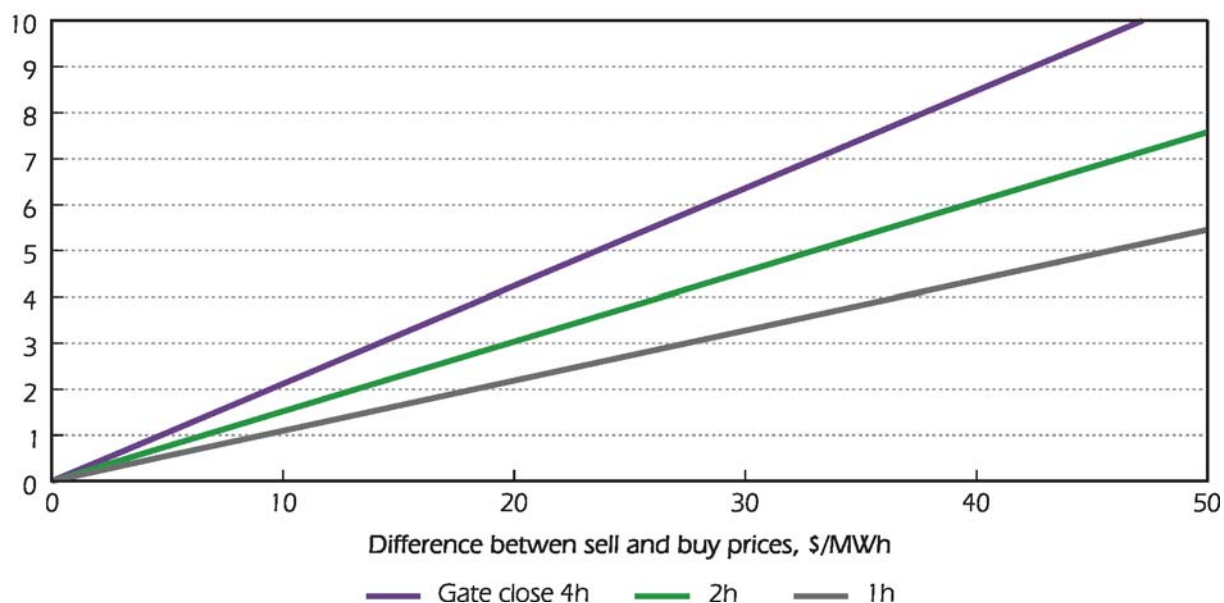
After a review, Ofgem, the UK electricity market regulator, accepted a proposal to reduce this time period to one hour. This will allow all market participants to limit their exposure to imbalance charges. Significantly, wind forecasts and modelling that form the basis of the supply schedule for each half-hourly period of wind farm operators, have a significantly reduced margin of error over this timeframe. Figure 9 illustrates the effect of reduced gate closure times. Reduced gate-closure times contribute significantly in reducing the spread between system buy and sell price and thus the effective penalty that has to be paid by the operator.

Nevertheless, another criticism is that NETA has resulted in far more spinning reserve being scheduled by the individual suppliers than is really necessary. This argument goes back to the point of balancing demand and supply on a systems level rather than requiring each individual supplier to balance their output individually. Since suppliers have been especially keen to avoid the higher SBP, "suppliers have typically chosen to be over-contracted at Gate Closure and generators have chosen to part-load some of their plant so that they can increase their output to cover any unforeseen outages in their plant which might leave them short of electricity." (Ofgem 2002:4)

On a system-wide level, some of the over- and undersupply at every point in time will be naturally balanced out leaving only a residual of imbalance in the market. The grid as a whole can only either be short OR long in a half-hourly period. Nevertheless, generators who are short when the system overall is short pay the SBP, thus imposing costs on suppliers as if they were directly connected to their end-customer, ignoring the benefits the grid delivers in this respect.

Figure 9: The benefit of reducing gate-closure times in the United Kingdom

Effective penalty for wind, \$/MWh



UK Source: Milborrow 2004a:38.

Connection of offshore wind

The development of offshore wind plays an important part in the market introduction strategy of many European Countries with access to coast lines. However, one unresolved key issue is the connection of these new wind farms into the national grids. At a recent workshop in Egmond aan

Zee, held under the auspices of the Dutch EU presidency, some of the important stepping-stones in this regard were agreed upon by representatives from governments, research institutes and industry. Even representatives from countries without a coast-line were invited since it was considered that the benefits from developing offshore wind could only be shared if a truly trans-European solution to grid integration was found. The declaration from the workshop makes this point strongly (Dutch Economic Ministry 2004): "In order to find European wide solutions to grid system issues like costs, size and dynamics related to system balance and interconnection, the European Commission should encourage, and where appropriate, support co-operation between Member States Governments, power plants and Transmission System Operators." The development plans for offshore wind in many countries could seriously surpass the narrow demand of coastal regions. Interconnection could allow a better sharing of both the costs to integrate these wind farms into the national grids as well as the benefits from high capacity renewable energy. While offshore wind farms are only magnifying this point by their sheer size, it has to be pointed out once more, that this principle applies to the integration of all kinds of intermittent electricity sources in general.

Already, three European interconnection projects that will aid the integration of offshore wind have been earmarked for up to 20% EU funding by the European Parliament, including an interconnector between the UK and continental Europe; an interconnector linking Ireland with the UK mainland; and increasing interconnection capacity between Denmark and Germany and other Baltic Ring countries (Windpower Monthly 2003).

Summary

The examples given above underline the fact the addressing intermittency of wind has only recently emerged as a priority concern of grid operators. Market rules are tested and revised and no clear preferred model of markets for ancillary services has been emerging yet. Similarly, upgrading of transmission lines and the interconnection of systems in general and for better wind integration is still in the planning stage and a model of sharing costs and benefits needs to be worked out. A recent study on the integration of wind energy into the national grid for example showed that the projected growth of wind power in Germany to some 36GW by 2015 necessitates an extension of the existing grid by about 5% of installed grid-km (Dena 2005).

In summary, policy-makers, regulators and grid operators as well as wind turbine manufacturers need to learn from the experience gathered and share information in order to arrive at solutions that work. The benefits of aggregation of wind power output have to be visible in balancing prices. The next chapters will summarise the key issues that should be considered in this context.

4. Summary and Lessons Learned

The question posed in chapter one was as follows: Given the expected rapid growth in renewable energy technologies over the next decades, are there technical limits to the integration of these technologies into electricity grids? The previous chapter examined in detail the evidence for this question in the case of wind power. This section will now draw together the main messages and will also discuss their policy implications.

Technical lessons from integrating wind energy

Although renewable energies and especially wind power already today play a non-negligible role in some IEA countries, the actual contribution to total primary energy supply is still limited. However, countries such as Germany integrate some 14,000 MW of wind power successfully, the United States and Spain more than 6,000 MW, Denmark around 2,300 MW. So far, problems with intermittency have occurred only on a regional level, highlighted by the cross-border congestion problems between Denmark, Germany, the Netherlands, Belgium and France (see chapter 3).

Current trends suggest a larger future role for renewable energy in electricity supply. For OECD Europe, the IEA's World Energy Outlook (IEA 2004b) expects a 16% market share of non-hydro renewables in the baseline-case by 2030. In an alternative policy scenario this share is projected to be over 23%. Several countries have ambitious policies and targets for renewables to play a more important role.¹² The ambitious plans, indeed, present the question of whether intermittency imposes technical limits on renewables in the future.

The evidence presented in chapter three indicates firstly, that current market shares of wind power have been technically integrated successfully into electricity grids and secondly, that options do exist to manage higher market shares of intermittent renewables in the future but at additional economic costs. Grid operators already possess tools to respond to system fluctuations of greater magnitude than will be imposed by current levels of renewables. Modeling and forecasting, as well as new communication technologies are current research priorities and will further refine these options. Innovative technologies for long-distance transmission of electricity, such as HVDC cables, open new opportunities for long-distance bulk transport of electric energy with low transmission losses. Market liberalisation and integration is already a major driver for the deployment of this technology. However, a larger share of wind power will ultimately require more flexible capacity reserve, and new and upgraded transmission and distribution systems. If these components are not developed simultaneously to expected growth in intermittent renewables, the stability of electricity grids will be threatened. In the future, new technologies and increased use of demand-side response measures could furthermore add to a more reliable grid operation, and reduce costs of integrating higher proportions of renewable technologies.

What does this mean to upper limits for renewable energy penetration? A general rule cannot be given, and much depends on different country circumstances and setups. The issues that arise at 20% market penetration of wind power in one country might well be experienced at 5% market

12. See the IEA Policies and Measures database at <http://repolices.iaea.org> and the Johannesburg Coalition Policies and Measures database at <http://jrec.iaea.org> for information on individual countries' programmes.

penetration in another country and vice-versa. Based on the practical experience gathered with wind power in a number of countries and the studies presented in this paper, table 6 below is a simplified summary of the issues that are likely to be encountered as wind power progressively increases its market share. The exact numbers will vary from country to country and new technologies might alter the picture significantly. Therefore, the table below attempts to differentiate three phases of increasing wind power market deployment rather than exact penetration levels, and shows how at each progressive stage, issues arise which should be considered in advance for the successful accommodation of wind power.

Table 6: Levels of wind penetration and corresponding issues

Wind development phases	Issues
Phase I	The added variability due to wind is not significantly noticed on the system, wind is treated as negative load; no major system adaptation is normally necessary and demands on transmission capacity are mostly within existing limits.
Phase II	Additional operational and capacity reserve will become necessary. Grid re-enforcements might become necessary, depending on wind location of wind resources and demand centres.
Phase III	Flexible capacity reserves increasingly gain in value; grid upgrades and new interconnections will become more important, depending on the historic structure of the grid.

Bearing the above in mind, a study of the Central Electricity Generating Board CEGB in the UK for example revealed that the existing system would need to reject a small amount of wind energy at certain times at a wind penetration of 10%, but could still work without major modifications even at 15% (BWEA 2004). It is stated, that even a wind capacity of 15,000 MW, *i.e.* enough to meet 13% of the UK's electricity demand at the time of the study in 1990, would still contribute to a smaller risk than one conventional power station being unexpectedly unavailable. This again underlines that a general rule cannot be given. Ultimately, the question whether there is an upper limit for renewables penetration into the existing grid, will be an economic and regulatory one rather than a technical issue.

Electricity systems as a whole continue to evolve and grid operators and utilities will ultimately have to adapt their methods, as they have in the past. The high concentration of wind power in northern Germany, and Western Denmark for example, might call for a joint operation of the balancing market, technical adaptation by the concerned utilities, collaborating on production forecasts, sharing data and possible grid extensions both on the German and on the Danish side, but all of these measures would add to the costs of reliable electricity provision. Potential future structural changes such as Distributed Generation with smaller flexible power generation units might become another driver of these types of system evolutions.

One relevant study in the context of structural changes was published by Kraemer (2003). This study aimed to optimise the costs for electricity generation in Germany under the assumption of high penetration of wind power (about 44 GW in 2020, so roughly a quarter of total electricity supply) and priority to wind power under the German Renewable Energy Sources Act. This study

shows that high penetration of wind power under cost optimised aspects and with the objective to reduce CO₂ emissions by 40% in 2020 will lead to displacement of base load power plants such as brown coal plants through a more flexible system based on wind and gas, with modest additional costs for wind power.

However, this approach would certainly require substantial changes in the energy systems and requires a change in paradigm; whether or not this change in paradigm is practical remains to be seen. Still, in many countries a significant number of conventional (fossil and nuclear fueled) power plants are to be replaced because of their age, thus opening the general opportunity for such a paradigm shift.

Economic and policy lessons

The discussion about intermittency of wind power has also brought about issues with wider electricity market implications. On a first level, the question arises whom grid integration costs are attributed to. In the context of intermittency, it has been argued that wind developers should be charged for transmission and distribution system upgrades and the increase in operational and capacity reserve that would become necessary as a consequence of wind power expansion. However, proponents of wind power argue that historically, these costs have always been recovered from all producers (and ultimately of course the customers) in the market and that new conventional power plant projects, such as the new nuclear power plant in Finland, also have wider system costs without that being necessarily charged to the relevant operator.

The difference between these views is substantial. For example, the additional system costs for renewables that have been calculated for a 20% wind and biomass scenario in the UK would be €4.9 per MWh (3.3£/MWh) of renewable generation but only €0.44 per MWh (£0.3/MWh) of total generation. From an economic point of view, each generator should be charged the proportion of costs that can be attributed to it in order to provide the right incentives to achieve a system-wide cost minimisation. However, given the legacy in the existing electricity markets of unspecific charges of system costs and the general network economics of electricity systems, structural changes in market designs and potentially new markets for reserves might become necessary.

In any case, it is clear that there has been as yet no universally adopted system of making the additional costs that intermittency imposes on the system transparent. The studies discussed above were often based on scenarios of coping with intermittency, without necessarily considering a market model of how these charges might be recovered. In many IEA member countries market designs have grown out of and in response to historic institutional structures and continue to evolve. Many markets have experienced phases of trial and error. Thus, in the following some general considerations for the charge of additional system costs are discussed, for the case of intermittent renewables as well as system balances in general.

In general, the most important issue which markets should address is cost reflectivity. For system balancing purposes, this means that market actors have the right incentives to increase their availability and provide precise schedules. Costs for maintaining system stability should be apportioned fairly according to how much each generator contributes to the need for keeping reserves, as well as potential transmission and distribution line upgrades. Here it might be important to highlight once more some first principles of system operation.

- Bigger units of power plants bring with them the need for both greater operational and capacity reserve since outages cause greater disturbances to the system, *ceteris paribus*.

- The higher the technical availability, the lower the probability of unexpected outages and thus the lower the requirements of short-term operational reserve, *ceteris paribus*. (Strbac and Kirschen 2000).

Wind power plants actually score favourable against both criteria, since they normally employ small individual units (currently up to 5MW) and have a record of high technical availability. Bad wind forecasting can diminish the second point, but as mentioned before, this is an area that currently receives a great deal of attention and promises significant improvements in the short term. Still, if a TSOs can pass on all balancing costs to customers then it faces little incentive to improve forecast accuracy, even less so if vertical integration implies that balancing services are contracted from own generation.

Strbac and Kirschen (2000) present a method to allocate the costs of reserve requirements based on both the capacity factor and outage rates of each plant. Milligan (2001) adapts this method for a model using real data from wind power plants in Minnesota, USA. The results show that in the most pessimistic scenario the highest reserve burden for the wind plants is 20% of its rated capacity, averaging about 3% throughout the year (Milligan 2001:4).

It might be asked whether in the context of cost-reflectivity the demand side would play a role as well since it also contributes to system uncertainty. Here, it has to be stressed that the current forecasting error of demand in most grids is in the order of 1%-5%, thus the scheduling of operational and reserve capacity is practically driven entirely by the supply side.

System operators will ultimately execute the physical balancing, as they are uniquely placed to have a system's view of imbalances. Thus, the smoothing effect of over- and underproduction of individual generating units is taken into account and only the residual imbalance is covered, providing a least-cost solution. Markets to organise the necessary resources should reflect this thinking and reward those generators that contribute to system's stability and only charge those that contribute to overall system imbalances.

Transparent, cost-reflective and interconnected markets for reserves will ultimately deliver the least-cost solution to grid integration of intermittent renewables. Market power by incumbent operators can prevent the development of such markets and is currently an important topic in electricity market regulation (Neuhoff 2005).¹³ Securing a wide variety of options and competition between these products has to be stimulated. Solutions will be needed to let both consumers as well as producers participate in these markets. Issues include transaction costs for novel participants such as demand-side response and distributed generation and geographic spread of such markets. Operating these "balancing" or "regulating markets" is an issue which will become more important for electricity market reform in general but is further illuminated through the challenge of intermittency. New products, especially for capacity reserves for occurrences of low output from intermittent renewables over longer time periods might become necessary.

Another important sub issue that remains is the gate-closure times of spot markets, which is an important variable especially for intermittent renewables. As has been discussed earlier, reducing gate-closure times to a technically necessary minimum could have real advantages, most

13. See Platts (2005:1-2) for a report on suspected market collusion in the German balancing market where four separate balancing market zones are maintained, leading to higher levels of required reserve.

importantly for wind power but also for conventional generation in general and thus for the electricity consumers as well. There will be a trade-off, grid operators will not always have flexible fast-response capacity available and this will be an important driver in considering to what extent gate-closure times can be shortened without imposing additional economic costs. Markets might not always be liquid in short-term trades, reducing the potential value gained for wind farm operators. Nevertheless, improved schedules for wind power, which specifically depend on weather forecasting and modelling operations, are likely to have significantly reduced margins of error which will contribute to system stability and reduced overall costs.

Since the costs of integrating wind in the grid are location dependent, a general concern is that the best wind resources might not always be where they are cheapest to develop. This might for example be the case where the resources are far away from major demand centres and grids are only poorly developed. Thus, there might be a balance in the benefits from the exploitable resource and the system integration costs for different locations. Countries could share these costs and benefits through wider grid integration which could also have benefits in relation to the wider competition concerns in electricity markets. Yet, an approach that is cost reflective would give the right locational signals and would provide an efficient basis on which to decide new renewables developments.

5. Conclusions: Lessons Learned for all Renewables

This paper started by outlining how natural cycles affect all renewable technologies over different time frames. While wind or solar PV technologies can change their output within minutes or hours, other technologies like hydro or biomass have seasonal variations of available energy. Many renewable technologies are in use in IEA member countries for many decades and have coped with this variation in available energy successfully.

As has been argued in chapter 2, the introduction of 'new' renewable technologies like wind or solar PV has added a new quality to this variability in that it added intra-day variations. Moreover, this has been magnified by the rapid growth in some of these technologies. Nevertheless, the fundamental principles on which these variations operate are known and should not come as a surprise. 'Traditional' renewables like hydro, geothermal and biomass were either part of national electricity supply from the beginning and have comparable operation characteristics as other power stations.

Given the high prominence of wind power among policy-makers, the media and in the research community, chapter 3 specifically examined the integration of wind energy into electricity markets. The main issues in terms of grid management and technological options to address the variability of wind have been examined and a review of policy and market issues was presented subsequently. It was concluded, that the experience with wind power showed that integration was more an economic and political issue than a technical issue. However, the importance of developing technical solutions concomitant to the growth of intermittent renewables to ensure electricity system stability was highlighted, especially in the case of grid extensions.

When considering the integration of renewable energy technologies into electricity grids, the broader evolution of the electricity market has to be taken into account. The pre-dominant fuel in electricity supply has changed in many countries over the past decades and is forecasted to do so in the future. The IEA's World Energy Outlook (WEO - IEA 2004b) expects a total investment into global electricity markets of \$10 trillion by 2030, of which almost \$5 trillion will go in new and upgraded transmission and distribution assets.

As renewables gain more significant market shares, some of this investment will benefit the integration of these technologies. There are six main areas of structural change that will directly benefit renewables. The first four presented below are likely to occur as a consequence of continued evolution of electricity markets and electricity grids. Other options might require further policy guidance. Each will briefly be highlighted subsequently.

- Increased grid capacity and cross-boarder connections, corresponding to the projections from the IEA's WEO.
- Balancing/Regulating markets that are cost-reflective, transparent and interconnected with gate-closure times reflecting the technical and economic needs on the system.
- Enhanced uptake of efficient demand-side response mechanisms.

- Installation of more flexible generating capacity, including hydro-power and biomass, as capacity reserves and increased efforts to reduce costs of novel storage solutions to widen the number of strategic options.
- A mix of different renewable energy technologies, taking advantage of different natural cycles and thus reducing volatility and uncertainty.
- Improved forecasting and modelling of natural fluctuations and increased utilisation of communication technologies to disseminate this information between grid operators and markets.

As chapter 2 described, some renewable technologies actually complement one another in their cycles. Solar PV resources are most available in summer while this is in many climates a time of relative drought with respect to hydro resources. Winds are often stronger in winter which is also a time of peak demand in colder climates.

However, as has been noted in the section on wind energy, renewable energy resources might not always be distributed equally. Some countries benefit from very windy regions while others have good biomass or hydro resources. While relying on one technology alone might be feasible if there is relative abundance or low penetration into the market, in the long run wider interconnection, and thereby utilisation of dispersed renewable energy sources on a wider geographical scale, is likely to become an important means of mitigating problems with availability due to the natural cycles.

In the case of wind for example, various studies have pointed out that not only geographic diversity of wind turbines can minimise the impact of intermittency but also a diversity of different technologies, exploiting renewable resources that follow different natural cycles. Specifically in the UK, two studies have compared systems that rely on wind alone with systems that have a combination of wind and biomass (Sinden 2002, Strbac et al. 2002). In both cases, the need for ancillary services and transmission line upgrades and thus the overall costs of the system were significantly reduced when wind was complemented with biomass generating capacity. On a wider geographic scale, Scandinavia has an interconnected market where hydro from Norway and Sweden is interconnected with wind in Denmark. A new interconnector will soon link the Norwegian and Dutch markets. The Bonneville Power Authority (BPA) in the northwest of the USA has supported wind farms in the region as one of the options for drought proving their vast hydro capacity (Felton 2004).

In summary, renewable resources are unequally distributed but often complement each other if interconnected to the same grid. The full potential of renewable energy resources lies in their diversity. Few energy systems in IEA member countries rely on one fuel exclusively and renewables are sometimes treated as if they all are essentially the same. As chapter 2 demonstrated, this is not the case and a strategy to develop renewables needs to take account of the different natural cycles that influence their availability. The global theoretical potential of renewable resources is vast, although estimates of what is economically recoverable vary. This potential varies regionally and a portfolio of technologies has to be used to harvest it to the full extent.

Traditional renewables such as hydro power and geothermal have participated in electricity markets for many decades. The intra-day intermittency of some of the new renewable energy technologies such as wind and solar PV makes it more difficult for these technologies to compete in mainstream markets. As has been reviewed earlier, what renewables are charged for in balancing markets is not always reflective of the actual economic costs that intermittency might impose. Transaction costs for hedging against these risks are high, especially for small operators, and balancing markets themselves are not always organised efficiently.

As markets continue to evolve and participants learn and better understand what the best rules and designs are to operate such institutions, this problem should gradually be addressed. The implementation of new communication and improved forecasting and modelling technologies will furthermore aid this task. Renewable energy technologies stand to benefit from markets which are widely integrated and where a wide variety of options, including demand-side response, storage, distributed generation and flexible power plants compete to offer the various ancillary services. In this way, renewables will become 'mainstream' in its characteristics and much akin to what market participants are familiar with today from conventional power plants. Furthermore, some of the integration efforts fall into the needs for restructuring electricity grids for better performance and more efficient operation.

Overall, should renewable energy technologies make a more significant contribution to energy supplies in the future, it is likely to be through a variety of technologies which will not be identical globally but will vary with the regional availability of natural resources and their cycles. In this perspective, higher contributions from renewable energy sources seem feasible. The technical barriers to such a strategy are well understood and current estimates of associated costs of system integration indicate that the economically exploitable potential remains significant.

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