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Distribution of the integration costs of wind power

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1 Preface

The present report is part of the project Wind Power Integration in Liberalised Electricity Markets (WILMAR) supported by EU (Contract No: ENK5-CT-2002-00663). The report forms the contractual deliverable D 7.1 as defined in the contract.

The integration of wind power into existing electricity markets entails the so called integration costs. How these integration costs are distributed on the actors of the electricity markets might have considerable impact on profitability of the total power system, investor behaviour and finally on the implementation of new wind power capacity. On the basis of the identification of relevant actors at the electricity market and of integration cost categories (chapter 2), this report identifies possible treatments for the distribution of integration costs and analyses the existing regulation approaches in individual countries (chapter 3). Subsequently an economic analysis of the consequences of the different cost distribution methodologies and recommendations for handling the distribution of these integration costs are given (chapter 4). Finally, the reports ends with conclusions (chapter 5).

2 Introduction

For an analysis of cost distribution models it is helpful to recall first that integration costs are (at least to certain extent) an artificial construct, which designate one part of changes in total system costs, when one new technology (in occurrence wind energy) is introduced /Weber 2005a/. Which part of additional system costs are defined as integration costs depends on the technology chosen as reference (cf. /Weber 2005a/ for details).

To identify different models of distributing the costs of integration of wind power and to qualify the consequences of applying these models the individual actors participating in a liberalised electricity system have to be defined. Furthermore a subdivision of the total integration costs into reasonable costs categories has to be made to determine different distribution treatments corresponding to different elements (for example power plants and transmission grids) of an electricity system.

Therefore in the following the relevant actors in electricity systems with respect to integration costs of wind power are presented. Subsequently the division of the integration costs into to relevant cost categories is derived and the impacts on these individual cost categories are described.

2.1 Relevant actors in electricity systems

For the description and analysis of the individual distribution models the following actors in the electricity systems have to be considered:

- Wind power producers
- Conventional power producers
- Transmission and distribution system operators (TSO and DSO)
- Consumers

Wind power can be one production form in the portfolio of power producers, however here power producers are distinguished into wind power producers and operators of conventional power plants in order to identify possible impacts of wind power producers on the operation of conventional power plants. According to the voltage level where the generated electricity is fed in there has to be considered a transmission or distribution system operator (TSO or DSO). As in the most cases the TSO or DSO is responsible for the physical power streams, possible metering companies are presumed to be part of the system operators. The individual electricity consumers are treated aggregated to one actor independent of the connection point to the electricity system and therefore there is no subdivision between purchasers of electricity from a TSO or of a DSO.

2.2 Relevant integration costs and benefits of wind power

The integration of the fluctuating and not perfectly predictable wind power into the electricity system may induce both additional costs and benefits. These impacts can be separated into capital expenditures (investments) and operational costs or benefits /GreenNet 2004a/. The investments can further be separated into:

- Grid connection costs
- Grid reinforcement costs
- Investments costs into regulating power plants caused by wind power

The operational aspects mainly consist of:

- Change of operational costs of conventional power plants due to wind power

In the following these sub-categories are further described.

2.2.1 Grid connection costs

The connection of a wind farm to the existent transmission or distribution grid requires the installation of an additional underground cable or overhead line from the wind farm to the existing transmission or distribution grid and the modification of the switchgear and transformer. Thereby common requirements on EU and national level like influences on voltages and short circuit levels have to be met. Further requirements are defined by the corresponding grid operator. The thereby evoked costs are calculated by comparing the additional costs to those of a hypothetical system, where the wind power farms would have the same distribution over regions, but are concentrated within the regions at the locations of already connected conventional power plants (cf. /Weber 2005a/). This comparison build on the assumption that the technology chosen as reference when calculating integration costs will be located the same places as existing power plants.

The grid connection costs can be principally subdivided into the costs of the local electrical installation (the internal grid) and the connection to the existing power grid. The latter part is the most interesting factor considering cost distribution and mainly depends on the following factors /GreenNet 2004a/:

- The distance of the wind farm to the point of coupling with the grid. This cost factor is essential for off-shore wind power farms.
- The voltage level of the connection line and the connected grid.
- The possibility to apply standardised equipment (cables, switchgears, etc.).

Grid connection costs are an important economic constraint for development of wind power farms in many cases where good wind resources are found in remote locations far from load centres. Therefore it is often the case that a compromise between locations with good wind conditions with potentially higher wind power production and locations without extremely high grid connection costs has to be found.

The costs of grid connection are mostly included into the total costs during the evaluation process of projected wind farms. The grid connection costs (absolute and relative to the total investment costs) for off-shore wind farms are certainly higher than for on-shore wind farms. For exemplary wind farm grid connection costs are estimated by /GreenNet 2004a/ as 12 % of the total investment costs for a on-shore wind farm and 20 % for a off-shore wind farm with 150 MW and situated 20 km from the shore and further 20 km to the nearest high voltage substation. /Dena 2005/ states for the connection of an off-shore wind farm to the German mainland a total of 544 k€/MW for the North Sea and 349 k€/MW for the Baltic Sea.

2.2.2 Grid reinforcement costs

Large scale wind power can require additional transmission capacities in the distribution and transmission grid, depending on the location of the wind farms relative to the load centres. For example in Germany the highest concentration of installed wind power can be found in the North whereas the main consumption area is in the midlands. Thus there are periods with high electricity transits from North to South and from East to West especially at weekends with high wind and low demand /Dena 2005/. As the grid was originally planned to supply the relatively low local demand in these regions, it has to be extended to meet the power stability and quality requirements. On the other hand, when wind power farms are mainly located near to load centres (e.g. Spain), the wind power production can reduce the occurrence of bottlenecks and delay the need of grid reinforcements. Hence, the evoked grid reinforcement costs are determined by comparing the costs of a system with regionally concentrated wind power farms to those of a hypothetical system with wind power farms distributed like the existing conventional plants, both within and between regions (cf. /Weber 2005a/).

The intermittent feed-in from wind power must be balanced with regulating conventional power plants that can be located elsewhere in the grid. Also larger control areas that can make use of regulating capacity from outside a country (e.g. the Nordic countries with a common regulating power market for 4 countries) require sufficient transmission capacities. Basically, wind power will change the power flows in the transmission system and new bottlenecks in the existing transmission grid may occur.

The more frequent operation of the transmission grids at full capacity leads moreover to a higher demand for reactive power in the grid. The possible generation of reactive power by conventional and wind power plants is not sufficient to provide the needed amount of reactive power to ensure that the voltage remains within the required range. E. g. for Germany, additional reactive power sources are required already for the forecasted wind power capacity of the year 2007 /Dena 2005/. Hence, further additional investments into utilities for reactive power compensation like capacitors, inductors and SVCs (Static Var Compensator) located at the corresponding locations of the grid will become necessary. The locations of the weak points in the transmission or distribution grid are derived with load flow calculations.

To improve the planning of grid extensions in order to enable an efficient use and connection of generation and demand, the derivation of future wind power scenarios is needed. This includes the exchange of information between the TSO or DSO and the investors of wind power farms at a very early stage. Thereby detailed information about project plans, time schedules, electrical configuration and exact locations of the connection points is needed /ETSO 2003/.

Generally the need for grid extension and the related costs depends on:

- The connected wind power capacity.
- The maximal need of power transmission as the difference between the maximum wind power feed-in and the minimum electricity consumption in a certain region. Thereby the probabilities of the occurrences of such extreme situations and the cost trade off between transmission extension and shedding of wind power production in these situations has to be taken into account.
- It has to be ensured that the connection of wind power plants does not lead to a decrease in power quality and system stability. To guarantee this, the limit values of voltage changes due to wind power feed-in and the short circuit level have to be complied with and the (n-1)-criteria has to be met.

There is a tendency for wind farms with large capacities (e.g. off-shore wind farms) to be directly connected to the high-voltage transmission grid. In this case, the extension of the local distribution grid can be avoided.

2.2.3 Investment costs into regulating power plants caused by wind power

Due to wind power forecast errors and the fluctuations in the short term the demand for reserve power both for up- and down-regulation will be increased, compared to a situation, where the same energy is delivered by a continuously operating plant. In regions with a high wind power penetration and mainly thermal power plants showing comparable small power gradients, additional manually activated up-regulating power can be necessary /Dany, Haubrich 2000/. In this case power plants running at part-load (spinning reserve) and eventually additional investments in flexible power generation technologies with low capital costs but with high variable costs are needed. Alternatively to the use of regulating power plants to compensate the intermittent wind power feed-in, technologies storing electricity like pumped hydro storages can be installed. The possible investment costs have to be covered by the trade at regulating power markets (cf. chapter 3.2 and 3.3.2).

However due to the spatial distribution of wind power plants the fluctuations of wind power within a short time span like one minute are currently often negligible in comparison to conventional power plant outages and variations of the total load. Thus there is no additional need for power plants providing frequency controlled primary reserve power and only limited need for additional automatic load flow reserve power due to wind power.

2.2.4 Change of operation costs of conventional power plants and benefits caused by wind power

The fluctuating and not exactly predictable wind power feed-in into the electricity system influences the operational strategy of the conventional power plant operators. The variability and not perfect predictability of the wind power output increases the use of regulating power to equal the total generation with the demand. The additional costs due to the wind power forecast errors can be determined by comparing the system with wind power to one with a hypothetical technology having the same, time-varying output but with perfect predictability. The resulting costs, taken with the opposite sign, correspond accordingly to the value of perfect forecast. Whereas the additional costs due to variations are described by the cost gap between using the wind power technology with perfect foresight and using an alternative source, which provides the same energy output as a constant flow (cf. /Weber 2005a/).

The need for up- and down-regulation can be met by using additional quick start capacity and conventional power plants running at part load (so called spinning reserve). More frequent start-ups of conventional thermal power plants due to drops of wind power feed-in lead to additional fuel and maintaining costs. Furthermore it can be assumed that existing conventional power plants are sooner worn out because they have to be run more often in operation modes that do not fit to the construction. Running conventional thermal power plants at part load causes operation with a lower efficiency and therefore an increase in fuel usage related to the electricity generated. Thus the allocation of providing reserve power between standing and spinning plants is a trade-off between the additional costs of the operation of quick start capacity with high marginal costs and the costs of running a spinning power plant with efficiency losses. Whereas in power systems that are dominated by hydro power plants (e.g. the Nordel power system), the needed regulating power can be provided fast and with low variable costs.

Depending on where wind power is situated compared to the load centres, a possible higher utilization of the transmission grid can increase transmission losses and therefore influences the costs due to a increased need of provided power. Moreover the possibilities for trading electricity over larger distances can be reduced because of the occurrence of bottlenecks in the transmission system.

On the other hand the replacement of thermal electricity production through wind power production saves fuel costs. Additionally a conventional power plant producer that also has wind power farms in its portfolio has the ability to save CO_2-certificates by providing electricity with wind power. When wind power is built as distributed power source in distribution grids, wind power can help to reduce distribution losses.

3 Existing methods for cost distribution

The sum of wind power integration costs can be subdivided into different cost categories and allocated to the individual actors of an electricity system by using varying cost distribution methods. In the following potential treatments to distribute additional costs linked to the integration of wind power are identified. Thereby the description of the individual treatments is organised according to the subdivision of integration costs into individual costs categories (cf. chapter 2.2). Subsequently the existing rules of cost allocation to the individual market actors in several countries are investigated.

3.1 Principles for the treatment of grid connection and reinforcement costs

The costs of connecting a wind farm to the grid and of possibly needed reinforcements of the grid near to the connection point or at remote locations can be allocated reasonably only to the owner of the wind farm or to the transmission or distribution system operator (TSO or DSO). Furthermore the costs of maintaining the grid have to be distributed as well. Thereby it is assumed that the TSO or DSO is obliged to connect a wind farm to his grid.

Normally the owner of the wind farm has to bear the connection costs including the installation of cables or lines and the coupling facilities at the connection point with the transmission or distribution grid (e. g. switchgear, transformer and meters). Thereby the definition of the connection point has consequences on the connection costs for the wind power producer and the TSO or DSO. This is illustrated by the differences of the Danish and German approach to determine the connection point:

In the Danish approach, the definition of the connection point can lead to a sharing of the costs of grid connection between the wind power producer and the TSO or DSO /Pedersen 2003/. This applies only if the wind farm capacity exceeds 1.5 MW. Then an area is assigned by public authorities to the corresponding wind farm and the grid connection costs within this area have to be borne by the wind farm operator. The TSO or DSO pays the construction costs of the connecting line to this area. Thereby the costs of the connection itself (e.g. installation of transformers and meters) are included.

In the German approach the TSO or DSO defines the connection point in the grid (e.g. a switchgear) that is capable to link the planned wind farm capacity with the existing grid. Thereby new voltage limits, increase in short circuit levels and power flow issues due to the additional wind power feed-in have to be considered. The wind power producer has to bear the costs of the line or cable from the wind farm to the selected connection point including the costs for the connection itself (e.g. transformers and meters). Thus the wind power producer will have much higher costs to connect the wind farm to the grid with the German approach. Furthermore the structure of the local grid and the power of the projected wind farm has more influence on the connection costs borne by the wind power producer.

For the payment of occurring costs of grid connection and reinforcement borne by the wind power producer the following procedures are possible:

- The occurring costs are paid by the wind power producer when the wind farm is installed (up-front or one-off payment). In this case the connection costs are typically assigned to the total construction costs of the wind farm.
- The TSO or DSO installs the connection as well as reinforcements and charges the costs to the wind power producer by imposing an annual fee per MW connected or per MWh transmitted. The charges have to be transparent and fixed depending on the present grid structure.

In some countries - not specified by /Ackermann 2004/ - the connection charges are set independently of the actual costs by a public regulator.

The individual methods to distribute the costs of grid reinforcements between the wind power producer and the TSO/DSO can be distinguished into three categories described in the following.

3.1.1 Shallow connection method

The treatment that the wind power producer has to pay only for the grid connection and not the grid extension is called the shallow connection method /DTI; Ofgem 2000/. Thus the possibly needed grid extensions beyond the connection point and at higher voltage levels have to be paid by the corresponding TSO or DSO. This method makes the connection costs for the wind power producer more calculable as he only has to consider the connection costs and not the structure of the local grid beyond the connection point. The shallow connection method gives no locational signal where the connection of the wind power farm is the most cost efficient concerning the overall connection and extension costs. As the wind power producer is not charged for possible disadvantages generated for the local grid, this treatment can increase the possibility of an inefficient design of the network and can cause over-investments. Furthermore the TSO or DSO may defer the connection of additional wind farms when this results into grid enhancements that are not concordant with the future grid development.

The TSO or DSO has to be regulated to prevent that their market power is used to impose too high use of system charges when socialising the grid reinforcement costs. There are three approaches for the regulation of the TSO or DSO possible:

- Cost-plus regulation: The TSO or DSO has to document its costs due grid connection of wind farms to the regulator. Then a reasonable mark-up that can be socialised is defined by the regulator. A variation of the cost-plus regulation is the rate-of-return regulation. With this approach the regulator sets the charge that the TSO or DSO is allowed to impose so that it can receive a predefined rate of return.

  The main disadvantage of this method is that the regulator has to get sufficient cost information from the TSO or DSO to define the mark-ups (information asymmetry). Furthermore as the revenue of the TSO or DSO increases by increasing the costs there is no incentive to minimise the connection costs. On the other hand this approach leads to incentives for connecting additional wind farms for the TSO or DSO as the guaranteed return increases.

- Price-cap or revenue cap regulation: The profit of a TSO or DSO is determined by its actual performance relatively to performance standards of power quality and cost effectiveness. The allowed prices or revenues are specified ex-ante by using a pre-specified formula (the so called CPI - X formula) considering a productivity factor and are adjusted after a certain period. Therefore a simplified model of the overall grid is assumed or a comparison with other TSO or DSO is carried out. This approach leads to the incentive to connect the wind farms to the existing grid more cost efficiently within a regulation period to extend the profit.
- Yardstick regulation: The regulator caps the socialised costs on the average cost level of TSOs or DSOs with similar demand and connected wind power. This regulation approach gives incentives for the TSO or DSO to connect the wind farms more cost efficiently than comparable TSO or DSO. The average cost level in the next price setting loop will then be influenced by the higher efficiency. Disadvantages of this approach are the appearing information asymmetry between the TSO or DSO and the regulator and the condition that the individual grids have to be comparable.

3.1.2 Deep connection method

By contrast the so called deep connection charges also include the costs of necessary grid reinforcements induced by the connection of a wind farm /DTI; Ofgem 2000/. Thus the wind power producer has to pay for grid adjustments beyond the point of connection and at higher voltage levels. With the deep connection charges the costs for the wind power producer will be certainly higher and more specific to the location of the wind farm, the generation capacity and the mode of operation. This leads to incentives for the wind power producer to locate a wind farm where the overall costs of grid connection and extension are the lowest. With this strong locational signal additional wind farms are connected favourably at points of the grid where the existing structure is stable and the fluctuating wind power feed-in has the lowest impact on grid stability. Thus the resulting design of the network would be more cost efficient than with the shallow connection method. This is due to the fact that the trade-off between locations with good wind conditions and with lower connection costs will probably increase.

The needed measures of grid enforcement have to be derived from individual load flow calculations and system quality studies for each additional wind farm. However the exact allocation of grid extension requirements and costs to individual wind farms is difficult and often non-transparent /Dispower 2004/. Improvements or even new lines do not benefit only to the corresponding wind farm but also to the reliability of the whole network. Another cost allocation problem arises in the case that a marginal wind farm triggers necessary grid extensions at a single grid point regardless of whether or not it is the major originator of the need of grid reinforcement. Furthermore the possibility of electricity trading is enhanced through these grid reinforcements. For all these reasons it is crucial to have common regulating rules to decide on the location and the amount of grid extension measures. In most cases it is the local TSO or DSO who is in the position to decide on necessary grid extensions as he is responsible for the power stability and quality. But this can lead to discriminations for the wind power producer.

3.1.3 Shallowish connection method

A similar approach to the deep connection charges are the shallowish connection charges. With this method the grid reinforcement costs are split between the wind power producer and the TSO or DSO. However, there is no common regulation for the subdivision of costs of grid reinforcements between the wind power producer and the TSO or DSO. One possibility is to introduce a limiting of the connection charges to a certain area around the point of connection. The costs of grid extension deeper in the network or at higher voltage levels are then borne by the corresponding TSO or DSO. With this treatment of shallowish connection charges the locational signal of the deep connection charges are combined with the advantage of shallow connection charges where the wind power producers does not have to bear the total grid extension costs. Furthermore the difficulties to allocate the needed grid extension measures to single wind power farms can be reduced. However, the price signals concerning local aspects of the grid are weaker than with deep connection charges.

To combine the shallow connection method with a location signal there is further the possibility to give an additional cost incentive for the wind power producer to develop wind farms at locations situated at more efficient locations concerning grid aspects. For this purpose the wind power producer pays an extra fee or capacity entry charge depending on the capacity of the wind farm and how it influences the reinforcement of the existing grid. The additional charges can be paid as an up-front investment or as an annual charge and can be positive or negative /Hiroux 2005/. The main difficulty with this approach is to determine the extra-fee or entry charge so that it gives the right location incentives to ensure effective grid connections and extensions. Thereby it is crucial again who has to decide on these additional charges.

3.2 Principles for the treatment of regulating power requirements and costs

The fluctuating nature of wind power and the occurring wind power forecast errors increase the use of regulating power or storage devices to balance the total electricity generation with the actual demand. The occurring capital and operational costs of the additional regulating power due to the wind power feed-in (cf. chapter 2.2.3 and 2.2.4) have to be distributed on the individual actors. In a liberalised electricity system this is done with a regulating power market, where the deviations between the physical power flows and the scheduled power flows derived from preceding trading actions at electricity wholesale markets are balanced.

Thereby it is crucial for the determination of the regulating power market prices in which way the individual wind power producer has access to the market: as individual market participant, in combination with further wind power producers as a wind power pool or in combination with a conventional power producer (e. g. as balance responsible player in the Nordel system). Depending on the used practice, the balancing prices paid by the individual producers differ from the system regulation costs. This is mainly the case when all imbalances and not the resulting total net imbalance are penalised.

As the wind power producer is the originator of imbalances and the TSO or DSO has in most cases the responsibility to balance the electricity production within its accounting grid the costs of regulating power are usually taken care of by one of these two actors.

In the case that the wind power producer has to bear the costs of regulating power the wind power is penalised with prices derived from the bids and offers at the regulating power market. If there are two different prices for each hour considering the total imbalance of the system, this treatment will be called a two-price model. To give an overview, the different amounts of net income for the wind power producer using this two-price treatment are showed in Figure 3-1. In the case that the actual wind power production delivered at the spot market is lower than the corresponding bid and this extends the total imbalance of the grid the wind power producer has to pay an up-regulating price that is greater than the actual spot market price. This rule lead to a negative income for the wind power producer when the up-regulation price exceeds the spot market price. In the case that there is an over-production and this extends the total imbalance of the grid the wind power producer is rewarded with a down-regulating price lower than the actual spot market price. In theoretical situations with negative down-regulation prices the wind power producer would reduce his production to prevent possible negative net incomes. If the deviation between the forecasted wind power production that has been bidden and the actual realised wind power production contributes to balancing the total electricity system (the wind power balance is in the opposite direction as the system imbalance), the wind power producer will be paid based on the actual spot market price. Hence, the wind power producer is penalised only for having its imbalance on the same direction as the total system.

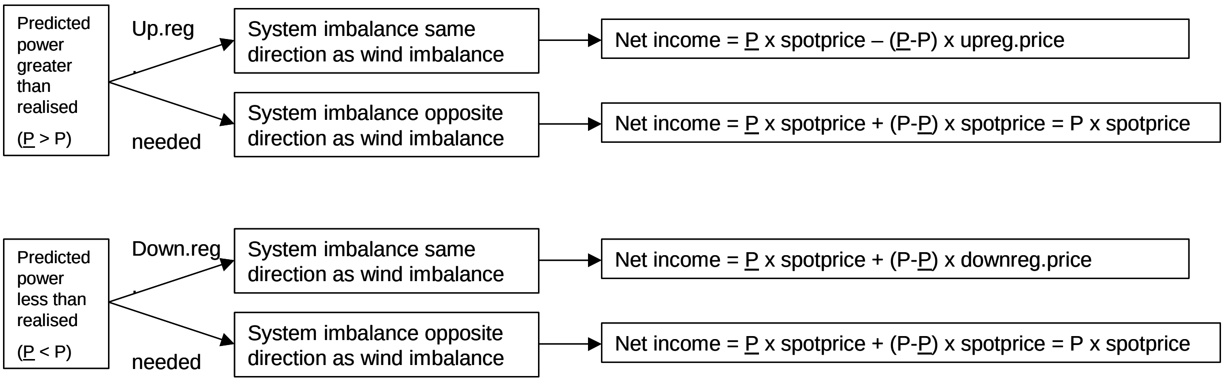

Figure 3-1: Net income for the wind power producer with the two-price treatment at the regulating power market /Holttinen 2005/. $\underline{P}$: predicted wind power, P: realised wind power, spot-price: power price on preceeding whole sale market

By contrast the one-price model uses a unique balancing power price paid or charged for any imbalances during an hour. This price depends on the system imbalance, but not whether the wind power imbalance has the same or opposite sign compared to the system imbalance. During the hours when the imbalance of the wind power producer has the same direction as the system imbalance, the wind power producer has to pay more like with the two-price model. In the other case when the wind power imbalance is to the opposite direction than the system imbalance, the wind power producer receives additional money than the spot price. With the one-price model, the payments borne by the wind power producer reflect the increase in total system costs caused by wind power. A further and simplified alternative to this one-price model would be the use of given and fixed penalty fees for under-production and low excess rates for over-production that are not dependent on the actual regulating market prices.

The regulating power market prices paid by wind power producers can also be derived from imbalances over a longer time horizon, e. g. one month like in California /Holttinen 2004/. This treatment reduces the regulating power costs for the wind power producer as the several imbalances are outweighed over time. However, system costs of occurring large imbalances during an hour may be ignored.

The treatment that the wind power producer has to pay the costs of necessary regulating power directly to the corresponding TSO or DSO is also possible. This requires that the actual wind power production is metered at the connection point of the wind farm with the grid and compared to the forecasted value. Thereby it is advantageous for the wind power producer when the directions of the imbalances of the entire system and of the wind power producer are considered. In the case that the wind power imbalance is on the opposite direction to the system imbalance, the wind power producer should not be charged.

With longer forecast horizons the forecast error on the hourly value of the future wind power production increases. Thus with longer time intervals between the market bidding hour and the delivery hour the need for regulating power increases. This leads consequently to larger costs of regulating power for the wind power producer. For example the closing hour of the Elspot spot market of Nordpool is at 12 o'clock for the day ahead /Nordpool 2004/, /Wilmar 2003/. Therefore a forecast time horizon from 12 to 36 hours ahead is necessary to determine the possible wind power offer. Thus the existing market structure leads to a strong incentive for the wind power producer to improve the existing forecast methods to reduce the costs of regulating power. Another alternative to reduce the costs of regulating power would be the change of the market design to shorter intervals between trading and delivery hours or the use of an after-sales market where the under- or overestimated wind power production can the traded more closely to the delivery hour (like the Elbas balancing market in the Nordic countries or of the BETTA in Great Britain (cf. chapter 3.3.2).

A further treatment is to allocate the responsibility of balancing the wind power production to the wind power producer. Then the following possibilities for the wind power producer to provide the necessary regulating power are identified:

- The wind power producer participates in the spot market and has the ability to purchase regulating power like other actors at the balancing market. Thereby the wind power producer has to get access to the spot market and to the balancing market and the wind power producer has to bear additionally the transaction costs of the markets where he takes part. For compensation of the regulating costs the wind power producer could receive a subsidy based per traded MWh or per installed MW.
- The wind power producer holds his own regulating power units or electricity storages. This means that the wind power producer has to consider additional investment and operation costs when projecting a new wind farm.
- The wind power producer pays conventional power producers or the corresponding TSO or DSO for the supply of the necessary regulating power capacity. This can be done on the base of a demand rate per requested MW and of an energy price per delivered MWh. As the wind power producer is in a competitive position with the conventional power producer, the charges for the regulating power capacity set by the conventional power producer will be comparable high /Ackermann 2004/.

The allocation of the responsibility to balance the wind power production to the wind power producer itself is not favourable. Generally the TSO or DSO is responsible for the secure and stable operation of the public grid. With this treatment the responsibility would have to be portioned on the individual power producers and actions that lead to an instable grid condition would have to be penalised by a central institution. However the correct allocation of imbalances to individual power producers is difficult to obtain.

In the case that the TSO or DSO has the responsibility to balance the intermittent wind power feed-in he can use own regulating power units or can buy regulating power from conventional power producers at different markets. If the TSO or DSO further has to bear the occurring costs of regulating power, they will be socialised by transmission or distribution use of system charges. Use of system charges are split in some countries into the costs for using the system based on the size of the demand and the geographic location and into the costs for balancing the system and maintaining the power quality in the transmission system /Ackermann 2004/. Thereby the latter costs differ between the individual TSOs or DSOs according to their grid structure and the connected wind power capacity. Therefore rules have to be established how use of system charges have to be assessed according to defined structure characteristics (voltage level, region, ratio cable/lines, demand density) or the individual TSOs or DSOs have to be regulated according to the approaches given in chapter 3.1. A further possibility would be that the additional costs are socialised between all individual TSOs or DSOs to prevent the discrimination of electricity consumers in grid areas that show a large concentration of wind power capacity.

The need of down regulating power can be reduced by wind power shedding through the TSO or DSO. In the case that the grid operator is permitted to shed wind power directives have to be defined whether the use of wind power shedding is based on the actual market prices or on predetermined legal rules. Furthermore possible compensation payments for the wind power producer in the case of wind power shedding have to be negotiated.

A further method to decrease the use of regulating power is the introduction of demand side management relating to individual electricity consumers. The affected consumers have then to be compensated for the controlled interruption of the electricity supply. The costs of these compensation payments can be socialised through the TSO or DSO. Alternatively the consumers can actively bid regulating power in the form of increased or decreased demand into the regulating power market, thereby obtaining a revenue for their flexibility. Consumers are present on the regulating power market run by the Nordic TSOs today.

3.3 Existing regulation practices

The identified categories of integration costs of wind power are distributed differently to the actors of the electricity system in different countries. To obtain an overview of the existing regulation practices an analysis of the legislation and directive rules in place has been carried out for several countries. Thereby the individual approaches are presented according to the identified cost categories (cf. chapter 2.2).

The selected countries are the Nordic countries (Norway, Sweden, Finland and Denmark) and Germany as treated in the Wilmar project. Additionally the legislation of Great Britain and of Spain have been analysed, the first because of its early deregulation measures and the latter because of its comparable high capacity of installed wind power.

3.3.1 Existing rules for grid connection and grid extension

According to a questionnaire-based survey with 20 participating countries that has been carried out by ETSO, there exists in every considered country the obligation for the TSO or DSO to connect wind power farms to the grid. But in a quarter of the cases the connection can be refused for technical and for economical reasons /ETSO 2005/.

In the following the existing regulation practices concerning the distribution of grid connection costs in individual countries are presented. Thereby the definition of the connecting point between the wind farm and the corresponding grid is important. Mostly the connecting point is located directly at the transmission or distribution grid at a location assigned by the TSO or DSO. In the following countries the wind power producer has to pay at least partially for the costs of grid connection according to the rules generally defined for all kind of generation technologies:

- Denmark /Pedersen 2003/: In Denmark there exists a specific order on the connection of wind turbines to the grid. Generally the wind power producer has to bear the costs of connecting the wind farm to a nearest connection point. In the case that one or more wind power plants in an area designated in a regional plan exceeds 1.5 MW, the TSO or DSO has to bear the costs of the extension of the grid to a connection point at the boundary of this area. Thereby the costs of the transformer at this connection point have also to be borne by the TSO or DSO. One can say that the connection costs are shared between the wind power producer and the TSO or DSO.

For off-shore wind farms installed within the main areas for off-shore wind power construction laid down in the off-shore wind turbine plan for Danish waters, the corresponding TSO or DSO has to pay the costs of laying the line up to the point where it links up with the internal network of the off-shore wind farm. Otherwise the costs of laying the line up to the nearest point on land shall be borne by the wind power producer and the costs of extending the grid to this connection point by the TSO or DSO. The costs of maintenance have generally to be borne by the wind power producer.

- Finland /EMV 1995/, /KTM 2004/: In Finland, the TSO or DSO generally has to connect power generation plants for a reasonable but not further specified charge. The conditions and technical requirements of the grid connections have to be impartial and non-discriminatory. Further the TSO or DSO has to give a cost estimate to the power plant owner. Thereby power plants using renewable energy sources have no priority.
- Germany /BMWA 2005a/, /BMWA 2005b/: The division of the connection costs is determined by the by-law /BMWA 2005b/ that entered into force 12th July, 2005. The costs of grid connection have to be compensated by the power plant owner through use of system charges. Thereby so called subsidies for the construction of the connection from the power plant owner have to be credited against linearly over a time period of 20 years. However, /BMWA 2005b/ does not provide any regulations for the imposition of these subsidies for the construction of the connection.
- Great Britain /NGC 2004/, /NGC 2005/: On the base of a bilateral embedded generation agreement the connection charges that has to be borne by the wind power producers are defined according to the transmission licence of the TSO or DSO. The payments are divided into one-off payments in relation to the construction of the connection site and annual site specific charges. The annual charges consists of charges for the provision of the connection by the TSO or DSO (gross asset value), for the depreciation of the gross asset value, for the capital costs and for operation and maintenance costs.
- Norway /IEA 2001/, /Filippini et al. 2001/: The TSO or DSO in Norway have to give access to all market participants on the same conditions. The regulation of the Norwegian Energy act concerning the grid is defined in relation to the connection point of the power plants to the grid (see the description of the regulation for grid extension in Norway). The costs of the installations of cables linking the power plant with this connection point at the nearest transformer station have to be borne by the owner of the power plant.

- Spain /CNE 2002/, /CNE 2004/, /CNE 2005/: In Spain, connection charges are imposed by the TSO or DSO for the construction of a new or the expansion of an existing connection of a power plant to the grid. The connection charges include firstly the so called extension charges that have to be borne by the individual or body corporate applying (termed the applicant) for the connection without necessarily having to contract new supply or its expansion. The extension charges are only valid for requested capacities lower than 50 kW_{el} in electricity grids with a voltage lower than 1 kV and for requested capacities lower than 250 kW_{el} in electricity grids with a voltage higher than 1 kV. In the case that the requested installation exceeds the capacity limits stated above, the applicant has to bear the costs of the necessary connection measures. Furthermore the connection charges consist of the access charges which are the payment to be made by the contractor of a new connection for the incorporation into the network and are depending on the voltage level and the connected capacity. The connection charges have to be a single nationwide charge.

  In the case that new connections give additional benefits for another consumer or generator, the new user has to contribute for the proportional part of the use of the installation capacity to the investments made by the first user. This obligation is only valid during a five year period starting from the commissioning of the connection.

  Operating and maintenance costs of connections to transmission grids have to be borne by the TSO.
- Sweden /STEM 1999/, /STEM 2002/: The legislation of Sweden defines a non-recurring fee (one-off payment) for the connection of power generation plants. The basic principle according to the examination of the reasonableness of connection charges levied by the TSO or DSO is that costs specific to owner of power generation units, i.e. the cost of work related solely to a particular proprietor should be covered by that owner. This work includes the connection between the power generation plant and the transmission or distribution grid. With respect to the maintenance and operation costs, owners of power generation plants with a maximum capacity of 1.5 MW have to bear only the annual costs of metering, calculating and reporting on the according TSO or DSO. In the case that several similar generation plants, located in the vicinity of one another, are simultaneously feeding electrical power into the network, the plants are to be considered as separate plants. Therefore DSOs which have particularly favourable conditions for small-scale electricity production within their licence areas have suffered considerable cost increases. These cost increases are then socialised among other consumers in this area. Further the threshold of 1.5 MW means that the capacity of certain wind power stations is kept down or that projectors avoid planning wind power installations with a capacity over 1.5 MW.

There is no analysed country where the TSO or DSO has to bear the entire costs of grid connection.

Concerning the distribution of grid reinforcement costs there is no European-wide harmonised rule yet /ETSO 2005/. In the following the existing legislation rules concerning grid extension of the individual countries are sketched:

- Denmark /Pedersen 2003a/, /Pedersen 2003b/: The TSO or DSO has to bear the costs of grid reinforcements and extensions and furthermore the costs arising by virtue of a wind farm connected to the grid. The costs are socialised to the consumer through use of system charges. Accordingly Denmark is an example for the shallow connection approach.
- Finland /EMV 1995/, /KTM 2004/: The TSO or DSO is obliged to maintain and develop the grid according to the reasonable requirements of the costumers. There is no provision that the wind farm owner has to bear arising costs.
- Germany /BMWA 2005a/, /BMWA 2005b/, /BDI et al 2001/: The costs of grid reinforcements are socialised through use of system charges. Before /BMWA 2005a/ and /BMWA 2005b/ entered into force, the division of grid extension costs was regulated by the convention /BDI et al 2001/. Thereby the power plant owner had to pay a grid extension costs subsidy to the TSO or DSO if the need for grid reinforcement could be allocated to the connection of the wind farm. The subsidy could be charged up to the next point in the grid that shows a sufficient capacity. The definition of this point and the assessment of this subsidy was done by the local TSO or DSO and not treated transparently. The remaining part of the grid extension costs have been socialised through use of system charges. Use of system charges were directly reduced through raising the subsidy. As a consequence of this kind of regulation several court rulings had to decide on the division of grid extension costs. Thereby the court procedure could significantly delay the construction and connection of the wind farm. Hence, a wind power producer might have been willing to sign a contract to have his wind farm connected as soon as possible and thereby missing certain rights that would have been confirmed by a court /Sustelnet 2003/.
- Great Britain /NGC 2004/, /NGC 2005/, /Hiroux 2005/: Grid works that are directly attributable to the connection and that may not give rise to additional connection assets are charged by one-off payments. These costs are set out in the so called Bilateral and Construction Agreements. Further grid reinforcements are paid over a longer period with transmission charges or Transmission Use of System (TNUoS) charges. To apply the TNUoS 15 generation areas were implemented to issue a locational signal. Thereby wind power producers in the North of England pay more than in the South because there are bottlenecks from North to South and deep transmission network reinforcements more likely required. In some regions with under-capacity the TNUoS is negative. Additionally there is a general level of charges to allow the TSO to recover his costs.

- Norway /IEA 2001/, /Filippini et al. 2001/: The costs of the grid extension up to the connection point are generally borne by the corresponding TSO or DSO. For compensation, tariffs for consumers and power producer are set as point tariffs according to the connection point regardless the distance of the transmission. The price setting of the individual TSO or DSO is regulated under a revenue cap approach (cf chapter 3.1).
- Spain /CNE 2002/, /CNE 2004/, /CNE 2005/: In the case that the connection of the power generation plant is applied for on building land, the power plant owner has to bear the costs of necessary reinforcements limited to the grid installation, where the new line is connected.
- Sweden /STEM 1999/, /STEM 2002/: The TSO or DSO is not permitted to recover from the proprietor of the wind farm with a capacity less than 1.5 MW the costs of necessary investments in the form of grid reinforcements.

3.3.2 Existing rules for providing regulating power and regulating power market structures

A detailed description of the regulating power markets in the Nordic countries and in Germany can be found in the Wilmar deliverable 3.2 “Power System Models” /Wilmar 2003/. In Denmark, until the end of 2002 the TSOs have been obliged to handle the regulation and the wind power having a prioritised dispatch. From the beginning of 2003, the owners of those wind farms supplying the spot market have been also financially responsible for balancing the power themselves. They can either continue to let the TSOs handle the balancing and pay the associated costs, or they can hand over the work to private companies. Hence, the wind power producers have to pay for their imbalance regardless of the total system net imbalance. To compensate the imbalances of individual wind power producers, an aggregation of individual wind power producers is advantageous. Consequently, some of the wind turbine owners in Denmark have formed a co-operative for handling the spot market trading and balancing of their turbines and this co-operative covers by now the majority of wind power producers entering the spot market. In the other Scandinavian countries, the wind power producers can corporate with balance responsible players. In the Danish, Finnish and Swedish power system the pricing of the imbalances is done according to the two-price model whereas the Norway uses the one-price model (cf. chapter 3.2) /Nordpool 2004/.

In Germany with its feed-in tariff for renewable energy sources, the total costs of purchasing and balancing the wind power production are socialised by imposing use of system charges through the TSO/DSO.

In Great Britain the market structure described below has been introduced with the New Electricity Trading Arrangements (NETA) in England and Wales in 2001. With the British Electricity Transmission and Trading Arrangements (BETTA) the trading arrangements have been extended to Scotland at the 1^{th} April 2005. Thereby the regulating power market of Great Britain is organised according to the Balancing and Settlement Code (BSC) which is administrated by a non-profit making organization called Elexon /GreenNet 2004b/.

The participation of the electricity actors in the bilateral forward or future market, the short term market or the balancing market is optional whereas the participation in the imbalance settlement process is mandatory. The transmission system operator National Grid is responsible for balancing the transmission system with the balancing mechanism (see below), DSOs are responsible for their own distribution grid.

The short term bilateral market operates up to one hour ahead of the actual delivery. There is the possibility for the sellers and buyers to correct their contract positions every half hour before they have to notify the offers and bids and their net physical power flows to the TSO or DSO at the closure of the market. This enables the market participants to consider more accurate forecast results of demand and supply.

Subsequently the balancing market ("Balancing Mechanism") operates from one hour before delivery up to real time. Thereby the TSO or DSO acts as the counterparty to all transactions. The participants have to submit offers to increase generation or decrease demand or bids to decrease generation or increase demand. The TSO or DSO purchases offers and bids on a "pay as bid" basis to balance the system and resolve transmission congestions. The actual power flows are metered in real time to determine possible imbalances. Then the magnitude of any imbalance between participants' contractual positions at the closure of the short term bilateral market and the actual physical power flow is determined. The resulting imbalances are settled in a one-price model (cf. chapter 3.2) with either the system buy price (SBP) or the system sell price (SSP). Either in the case that the system is short the SBP or in the case that the system is long the SSP is defined through a forward market price derived from power exchange trades. Thus the causing market participant is charged for power deficits with the SBP and for power surpluses with the SSP. Generally the SBP exceeds the SSP. The imbalance prices are working as incentives to the market participants to contract as sufficiently ahead to the closure of the short term market to ensure that the bids and offers represent the physical power supply. Bids and offers that are related to system balancing like resolving transmission bottlenecks are excluded from these imbalance charges. Furthermore an adjustment to the imbalance prices is made based on pre-gate closure balancing that the TSO or DSO has used for system balancing.

National Grid as the common transmission system operator has the general obligation to operate the transmission system efficiently and economically by using balancing services and the bids and offers at the balancing mechanism. With the so called balancing services incentive arrangements, the British regulator Ofgem can reward National Grid in the case that the system operator meets cost targets set by Ofgem.

Principally wind power producers are integrated in the British power markets in the same way like conventional power producers. This may cause high balancing costs for wind power producers as the imbalances through wind power forecast errors are charged with the balancing mechanism. But due to the renewable obligation which sets a target for conventional power producers to generate a least part of their electricity production on the base of renewable energy sources, the conventional power producers have the incentive to use renewable obligation certificates bought from wind power producers on long term contracts to meet their renewable targets. Thereby the conventional power producers often take over the balancing risk, so that the wind power producers can avoid the participation in the short term and balancing markets /GreenNet 2004b/.

4 Economic analysis

In an economic perspective of social welfare maximization, the issue of providing efficient price signals to economic actors is at least as important as the question of cost distribution. To get the prices right in order to have the market providing efficient solutions to the integration of renewables – this is the key challenge from an economic viewpoint.

Such a line of thinking leads straightforwardly to the introduction of locational pricing as the best remedy to all kind of allocation problems in electric grids, including the distribution of so-called integration costs attributable to renewables. Given the quasi non-storability of electricity, the locational (nodal) prices should be real-time prices to reflect the actual scarcities of electricity (and ancillary services) in different locations. In a competitive environment, economic agents will then provide the optimal amount of renewables and other production in the right places by anticipating the future development of the locational prices (or relying on correspondent derivative contracts). This is the essence of the theory, yet its application is complicated by several real-world phenomena, notably:

1. the natural monopoly character of the grid,
2. the existence of transaction costs,
3. the existence of information asymmetries,
4. the additional requirement of robustness.

Ad 1: The natural monopoly of the grid has two key consequences: there will be usually one grid operator per region, who has then to be regulated in order to avoid excess monopoly profits. Locational pricing will hence not emerge by itself from competitive forces but will have to be imposed on the grid operator by a regulator. As an exception, it may emerge spontaneously, if the grid operator is state-owned and benevolent, pursuing hence by himself social-welfare maximizing objectives. The second, as important consequence is that a pricing system based on marginal cost will not recover the full cost of operation of the grid. Rather the sub-additive cost function of the grid makes the last (additional) use cheaper than previous uses. When it comes to calculating integration costs, it consequently also matters in which order different functions or users (e.g. trading, renewables) are added to the grid.

Ad 2: The existence of transaction costs makes locational real-time pricing not an as attractive alternative as it seems to be at first sight. Especially for smaller scale renewable plants the costs of transmitting real-time information to the plant operator and enabling him to react may exceed the potential benefits from such an approach. The existence of transaction costs may be taken as a justification for the introduction of day-ahead markets, zonal pricing or other simplifications compared to real-time nodal pricing.

Ad 3: The existence of information asymmetries complicates further the emergence of efficient solutions since both grid operators and operators of renewables power plants may withhold information in order to increase their profit. Clear rules on the sharing of operational information and a culture of common information building for strategic decision making may help to overcome these information asymmetries. Yet a careful assessment is needed to weight costs vs. benefits of increased transparency taking also into consideration that high transparency may increase the danger of collusive behaviour in oligopolistic markets like the wholesale electricity market.

Ad 4: The requirement of robustness means that the system should remain stable even if the actors in the system have perceptions of the system dynamics which differ from the reality. Robustness thus goes beyond the classical requirement of system stability. It is however a concept widely used in modern technical control theory and it should also be taken into account at the frontier between technical and economic electricity systems. Given the general trade-off between robustness and efficiency (cf. Zhou, Doyle 1998, Weber 2005b) a certain loss in efficiency is to be expected also if considerations of system stability are taken seriously[1]. Losses in efficiency here mean additional costs compared to the welfare optimal solution without dangers of system misperception.

4.1 Implications for the treatment of grid connection and grid extension costs

From the previous reasoning, the following implications for the treatment of grid connection and grid reinforcement costs can be drawn:

1. Grid connection costs which are clearly attributable to a single renewable installation should be born by this installation. Whether they are charged as one lump-sum payment or as a fixed annual fee is however of minor importance for efficient grid operation - it is an issue of capital budgeting.
2. Deep grid connection charges are in principle better suited to reflect real-time scarcity than shallow connection charges. Yet they remain a considerable step behind real-time locational prices, given that they are usually calculated ahead of the investment and do not reflect changes after the construction. They will thus at best provide adequate investment signals but no adequate price signals for operation. And if they are determined based on an incorrect anticipation of later scarcity, they may even provide wrong locational signals at the time of construction.
3. Grid extensions deep behind the point of connection usually have multiple benefits. E.g. in the dena study the benefits of extensions in the German transmission grid both for wind integration and electricity trading are mentioned. Consequently the costs of such grid extensions cannot be attributed solely to one source.
4. The location-dependent benefits or costs of new investments - be it in wind turbines or in grid reinforcements – may vary over the lifetime of the investments. Consequently deep connection charges (or a location-dependent so-called “generation component” or “G-component” in grid tariffs) should not be fixed once for ever, but revised regularly according to a transparent mechanism.

[1] A detailed analysis of the compatibility respectively divergence of the three concepts of 1) electrotechnical system stability 2) optimal (and/or robust) stable control 3) economic efficiency and robustness is beyond the scope of this paper. This is however a challenging theoretical issue of considerable practical relevance.

5. Such a time-varying connection price for wind energy installations with revision periods between one and five years may be a suitable compromise for wind generators. It puts some of the risk of future changes in local scarcity on the investors, but the risk exposure is in a well-designed system smaller as with full real-time locational prices[2]. And obviously the transaction costs tend to be lower.

4.2 Implications for the treatment of regulating power

For the treatment of regulating power and corresponding costs, the following basic considerations have to be taken into account.

a) Two aspects have to be distinguished conceptually: the creation of market mechanisms, which lead to a minimisation of regulating power costs and the distribution of the resulting costs on the actors concerned. But obviously any market design will have implications both for the cost height and its distribution.
b) With typical feed-in tariffs, as currently in place e.g. in Germany, wind power producers will not bear directly any costs of the additional regulating power needs they are causing. With most other renewable support schemes, such as tradable renewable obligations, procurement schemes or bonus payments, wind power producers participate in the conventional power market and thus also have to bear costs of deviations from schedule – i.e. regulating power costs. Consequently wind power producers have no incentives to reduce regulating power under feed in tariffs, whereas they have such signals under other support schemes.
c) Zonal pricing with automatic price splitting as currently practised in the NORDEL region is from a theoretical point of view clearly a second-best solution compared to nodal pricing[3]. The key point thereby is that zonal pricing requires transmission capacities between pricing zones to be computed ex-ante, before the trading takes place. In practice however the transmission capacities between two regions are not only a function of the thermal capacity of the lines between these two regions, but also of the location of all the power generators and power sinks in the system[4]. This location may vary from day to day, especially due to trading-induced variable scheduling of power plants. And obviously varying wind generation also tends to modify the distribution pattern of generators (and sinks – if demand side management is applied). Under uncertainty about generation location and wind production, the grid operator will tend to set conservative transmission limits, which may constitute unnecessarily high restrictions to trading, leading hence partly to unnecessary market splitting and correspond-

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[2] However such slowly varying prices do not provide adequate locational signals for physical electricity trading and the conventional power generation behind it.

[3] Zonal pricing with explicit auctioning of cross-border capacities as currently practised in the rest of Europe is even less efficient. But here things are evolving, albeit slowly.

[4] This is a direct consequence of the laws of physical load flow in meshed grids.

ing efficiency losses. A nodal pricing system avoids these difficulties by determining simultaneously the load flow and the prices[5].

d) Regulating power is in a general sense any power needed to compensate deviations between scheduled power flows at the moment of spot market closure and actual power flows[6]. Clearly the market trading has to close before the actual operation in order to allow the system operator a stable operation, not disturbed by sudden last-minute trading operations. He needs therefore regulating power reserves. However this raises two important issues: how long is the distance between spot market closure and actual delivery? And how are the bids for regulating power coordinated with bids for the spot market?

e) From the perspective of a conventional power plant operator, the spot market and the (upward) regulating power market are two alternative sources of revenue. In any market design, which does not preclude from the outset arbitrage between these two markets, power plants will earn at least as much when delivering upward regulating power as when they provide power traded on the spot market. The earnings from the regulating power market will exceed those from the spot market if and only if scarcity is higher for flexible power plants (as needed for regulating power) than for predictable power traded on the spot.

f) No simple solution for designing regulating power markets exists. Or more precisely: simple solutions tend to be inefficient and efficient solutions tend to be difficult to implement. This holds especially for the German and other continental European power systems, where flexible power plants are scarce, given that thermal power plants dominate, and where in each regulating market zone (or each pricing node in a nodal system) there exists one dominant firm. A further key issue thereby is that in Germany the amount of automatically activated regulating power is much higher than in the Nordic system, given the UCTE rules[7].

These general considerations lead to the following implications:

1. For the distribution of regulating power costs caused by wind energy, the basic question is, whether wind power participates in the conventional power market or not. The

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[5] In a system of full locational pricing, not only active power should be priced but also reactive power. This will then also lead to appropriate locational and operation signals for providers of reactive power.

In such a context moreover even a temporal overloading of transmission capacities could be taken into account. Yet in this case, path-dependency in prices is not only induced by the operation restriction of generators but also from the grid.

[6] This general definition of the term regulating power is complicated by the fact that some countries have energy trading taking place after the closure of the spot market on intraday or balancing energy markets (e.g. Denmark and other Scandinavian countries). Then regulating power is only the power activated according to the system net imbalance during the operating hour. In fact, intraday or balancing energy markets are in these cases the “real” spot market, i.e. the market closest to actual delivery. Yet this definition is not commonly shared, notably given the usually limited liquidity of intraday and balancing markets in the countries concerned.

[7] Those foresee an automatically activated secondary reserve, where the activating is done based on the current load-flow across the borders of the grid area under control.

decision on the promotion scheme will however depend also on other considerations than the provision of efficient regulating power price signals.

2. If the wind power does not participate in the conventional power market – as is currently notably the case in Germany – the costs related to required regulating power will usually be born by the grid operators and hence ultimately by the grid users. The distribution of these integration costs then depends on the general rules for the sharing of the renewables costs. These can be distributed on a per MWh consumed basis (as currently in Germany) or proportional to the grid charges paid.
3. A charge of imbalance costs to wind power operators in a system, where they do not participate in the market will always provide some inconsistencies. In particular the use of predefined imbalance tariffs usually does not reflect the real-time scarcity nor does it take into account portfolio effects.
4. If the wind power participates in the conventional power market (as in Norway, UK and Denmark[8]), wind power producers will usually also have to bear the costs of any imbalancing they are causing based on the current balance power price. With a functioning balancing market this provides efficient operational signals to the power producers, if they are charged a uniform real-time price, which reflects the overall system imbalance (and not the individual imbalance) as well as the real-time scarcity of flexible power generation. The use of an asymmetric imbalance tariff (two-price model as currently in place in all Scandinavian countries except Norway) does not provide adequate scarcity signals in that it does not reward imbalances being in the opposite direction of the total system imbalance.
5. In this setting, the amount of imbalances to be paid for by wind power producers strongly depends on the time span between closure of the spot market and actual delivery. A rather short delay is preferable, such as in the British BETTA trading system, since then the forecast errors for wind energy are low.
6. If the time span is longer, the efficiency of the regulating power market is key. If market power is an important issue in the regulating power market (as seems to be the case currently in Germany), wind power producers (and consumers) will be charged too high regulating power costs.

[8] Only newer wind power installations participate directly in the power markets.

5 Conclusions

The objective of this report is to identify different treatments to distribute the costs of wind power integration on the individual actors of electricity markets and to derive recommendations for handling the distribution of these integration costs based on an economic analysis.

With regard to the distribution of grid connection costs, the existing practices show similar treatments that allocate the costs to the individual wind power producers corresponding to the recommendations derived in chapter 4. Concerning the costs of necessary grid reinforcements, the shallow connection method dominates the existing treatments. This is contrarily to the recommendations that favour price-flexible locational signals. Since grid reinforcements have multiple benefits for the operation of electricity grids and for the trading at electricity markets, these costs should be allocated reasonably to several user of the grid.

The structure of the present markets as well as how the wind power producers have access to the markets are crucial points for the distribution of occurring regulating power costs due to wind power. Key issues are the different price models for the regulating power price and the time spans between the closure of the trading activities and the actual delivery hour. The existing plurality makes an harmonisation of possible methods for an efficient cost distribution difficult. To provide efficient operational signals to the individual power producers, it has to be ensured at least that the marginal regulating power costs borne by the individual power producers are equal to the marginal costs of the net imbalance.

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