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SUPWIND Deliverable D 8.1

Assessment of market designs for energy and ancillary services

Report on Findings of Working Package 8

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Content

Preface

This deliverable is part of a series of working documents within the project *Decision Support for Large Scale Integration of Wind Power SUPWIND*, supported by European Commission within the 6th FP under Contract No. TREN/05/FP6EN/S07.61830/020158 SUPWIND. It describes the outcomes of Working Package 8 and is structured as follows.

Chapter 1 gives a general introduction to the needs and possibilities of evaluating market designs with help of market models. In the 2nd chapter some insights on the functioning and the design of intraday markets is given. After this the SUPWIND planning tools are used to assess the benefits of different market configurations for trading of balancing services (chapter 3) and for the possibility of coupling physical constraints and trading decisions (chapter 4).

1 Introduction

This deliverable summarizes some reasons why intelligent market design can help to integrate wind into the power market. Fluctuating wind has manifold impacts onto power system operation. Most important, the volatile characteristics make it more difficult to plan the dispatch of conventional generation units. This is due to the fact, that wind power production can't be as good forecasted as conventional generation. The dependence on metrological conditions makes prediction of wind production in a long run perspective problematic. In the short run wind prediction is difficult too and very often there are deviations in realized wind and in wind forecasts before the closing of the day-ahead market. These deviations have to be handled by the TSOs via redispatching of conventional generation. A proper market design might help to reduce the costs of such a redispatch and hence it might reduce negative impacts of volatile wind production on overall power system cost. These cost are often labeled as integration cost and they are mostly due to the inefficient operation of conventional energy sources. In the following it will be tried to give some recommendations on the design of reserve and intraday markets, which might be used when redispatching (chapter 2). We make use of the SUPWIND market models and databases to quantify the impact of different constellations in reserve markets and we will demonstrate the usefulness of the SUPWIND tools in addressing policy issues. It will be analyzed how large the benefits of intraday rescheduling are and whether international exchange of reserves is helping to reduce overall system cost. At last we will address the often discussed issue of market coupling, which is discussed by TSOs and market operators. We investigate the magnitude of welfare effects in coupling physical load flows with market operations.

2 Fluctuating Wind Energy and Adequate Market Design for European Power Systems

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Abstract

This contribution analyses the European electricity markets with respect to their aptitude to absorb large amounts of wind energy. Thereby in a first step the market designs of the major European power markets in France, Germany, Scandinavia, Spain and UK are reviewed, with a particular focus on liquidity in the spot and intraday markets. Then some key features of the short-term adjustments required by wind energy are discussed and the necessity of sufficient liquidity in intraday markets is highlighted. For the example of the German market subsequently the discrepancy between the physical short-term adjustment needs and the traded volumes on the intraday market is analyzed. This leads to an evaluation of proposals for improving the liquidity on the short-term market, including the use of continuous spot trading like in UK or the use of intraday auctions like in Spain.

Introduction

The transmission system operators all over Europe have been confronted with new challenges as a consequence of the liberalization of European electricity markets. Further challenges lie ahead both for system operators and electricity market operators in Europe with the on-going strive for renewable power generation. With wind and solar energy getting increasingly popular as ecological, emission free energy sources, the question is gaining importance, how the inherent fluctuations in their production should be dealt with best at the level of system operation and market design. Without adequate measures being taken, the inherent fluctuations of wind and solar power would obviously make them very poor substitutes of conventional, controllable electricity production from coal, gas, nuclear and other power plants.

In particular, the organisation of the continental European and Nordic power markets, based mainly on day-ahead spot markets, induces high demands for regulating power and/or intraday trading to cope with increased amounts of wind power. Yet any change of market design comes at considerable costs and may have adverse impacts on liquidity. Therefore the contribution analyses, how the market design in the European countries could and should be adapted to the new challenges arising from Wind Energy. The implications of wind energy for prices on the day-ahead and intraday markets have been subject of several papers, including Barth et al. (2006), Weber, Woll (2007), Sensfuß et al. (2008), Wissen, Nicolosi (2008). Also the question of suitable market design for the integration has been repeatedly discussed, notably by Holtinnen (2005), Barth et al. (2008) and Maupas (2008). Yet most of these contributions focus either on the spot market or the balancing energy mechanism. A notable exception is Maupas (2008), who simulates in detail the interplay between the intraday market and the balancing energy mechanism. However Maupas takes the liquidity in the intraday market as given. Hence a major aspect discussed in this paper is the liquidity under different market designs, both for spot and for intraday markets. The overall objective of any reforms in market design should be an improvement of the global efficiency of the markets. Thereby an increase in liquidity will in general be beneficial, since without sufficient liquidity, trading will not occur and hence also an efficient use of production resources will be hindered.

Liquidity is here and in the following defined in accordance with the literature (e.g. Ghysels and Pereira 2008) as the possibility of selling or purchasing a commodity in larger quantities without moving the market price too much. Defined this way, liquidity is not directly observable in markets. Yet a useful indicator for liquidity is the trading volume in a market (cf. also EU 2007). This is easily observable and will therefore also be used in the following for characterizing market liquidity.

As defined above, liquidity is in fact also a prerequisite for low transaction costs. Without sufficient liquidity, any market participant must fear that his purchases (or sales) move the market price and make him pay more (respectively earn less) than the unperturbed market price. In fact, this kind of transaction costs is much more important for energy trade than the pure transaction fees paid to power exchanges or brokers, which usually are far below 1 % of the price. Also for larger energy companies, the potential liquidity costs are far more relevant than the internal transaction costs related e.g. to IT systems or trading staff.

The remaining of this paper is organised as follows: in the next section an overview on the market design in major European countries is given with a focus on liquidity, then the needs for short-term adjustments arising from wind energy and other sources are discussed in section 3. The key issue of liquidity on intraday markets is subsequently investigated in more detail taking as an example the German market in section 4, whereas the interconnection with the reserve markets are addressed in section 5. Finally section 6 reviews different proposals for improving the functioning and the liquidity on the intraday markets.

Market Designs in Europe

In order to assess the necessary steps for improved wind integration, first the current design and functioning of major European electricity markets is reviewed. The focus is thereby on the Nordic, the UK, the German, the French and the Spanish power markets. Major characteristics of these markets are summarized in Table 2: Spot markets in the countries considered. An overview of the sequence of interrelated markets is also given in

Table 2: Spot markets in the countries considered: Considered markets in Europe

Country	Grid operator(s)	Market Operator	National Consumption (2007)
France	RTE	Powernext	480 TWh
Germany	RWE Transportnetz Strom E.ON Netz Vattenfall Transmission EnBW Transportnetz	EEX	556 TWh
Nordic Countries	Statnett Svenska Kraftnaet Fingrid Energinet.dk	Nordpool	395 TWh
Spain	REE	OMEL	268 TWh
UK	National Grid	APX UK	373 TWh (2006)

Sources: UCTE (2008), own research

A first key point to be made is that none of these markets is run by an Independent System Operator (ISO), similar to the ISO in the Pennsylvania-New Jersey-Maryland (PJM) market or in other US markets. Rather the markets are organized as bilateral, voluntary markets, working at least to some extent independently from the grid management, even though often the Grid operators hold major shares in the power exchanges.

In all countries considered, the power exchanges operate a general market labeled "spot market", which is the main market for physical delivery[1]. Its characteristics will be discussed in detail in section 0. Additionally, for short-term adjustments often intraday markets are operated either by the power exchanges or by other institutions. Their characteristics are reviewed in section 0. In order to have sufficient reserves to handle remaining deviations

[1] In line with common practice in Europe, the term spot market is used to designate day-ahead or similar markets and not real-time markets.

between scheduled and actual operation, the grid operators moreover mostly operate reserve markets, which are explained in section 0. The sequence of these markets is also illustrated in *Figure 1: Trading on different electricity markets.*

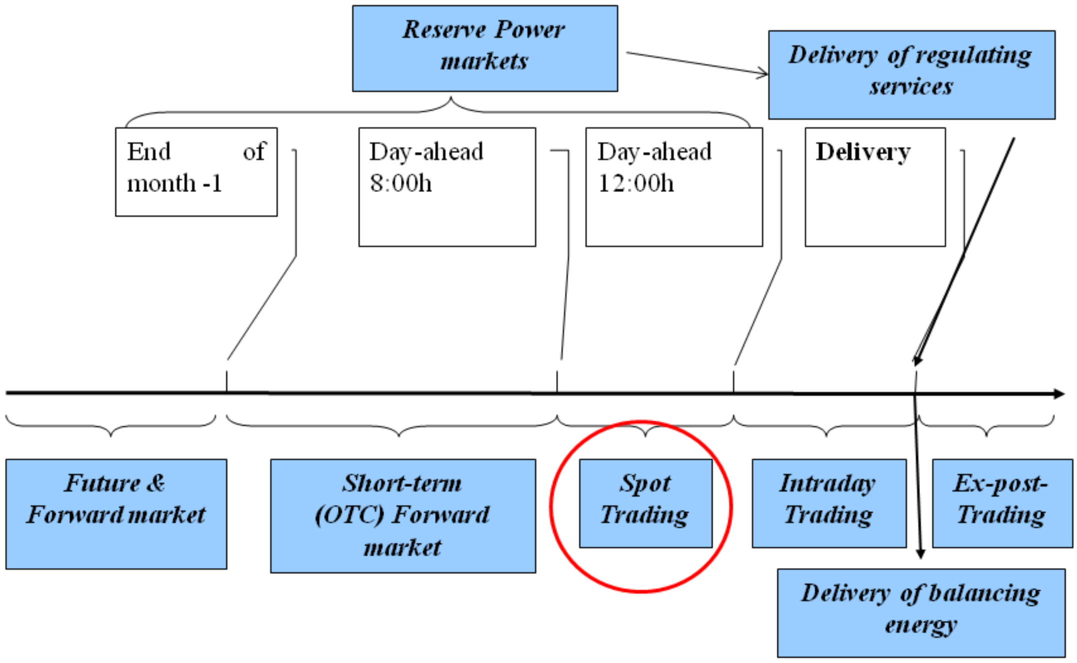

Figure 1: Trading on different electricity markets.

Spot Markets

Trading in the power exchanges has considerably increased during the last years and a comparison of the percentages compiled in for 2007 to the data used in the EU sector inquiry, which refer to a time period in the years 2004-2005, show partly impressive increases[2].

The share of total consumption traded at the exchange increased in Nordpool by 30 percentage points, in Germany the values are up by 9 percentage points and for France an increase by 6 points compared to the values published in DG Competition's sector enquiry (EU 2007) is observed. Nevertheless less than 25 % of all electricity consumed is traded at the spot market in the majority of the countries.

[2] Note that the EU sector inquiry (EU 2007) has been published in 2007, yet the data used there are mostly covering the periods 2004 to 2005.

Table 2: Spot markets in the countries considered

Country	Market Operator	Spotmarket gate closure	Exchange traded Spot volume (2007)	Share of national consumption
France	Powernext	11:00 day-ahead (7 days per week)	44 TWh	9 %
Germany	EEX	12:00 day-ahead (Mo-Fr)	123 TWh	22 %
Nordic Countries	Nordpool	12:00 day-ahead (7/7)	291 TWh	74 %
Spain	OMEL	10:00 day-ahead (7/7)	195 TWh	73 %
UK	APX UK	60 min before delivery (7/7)	10.6 TWh	3 %

Sources: EEX (2008), EU (2007), Nordpool (2008) , Ockenfels et al. (2008), OMEL (2008), Powernext (2008), own calculations

The situation is however different in the Nordpool market. To some extent, this is certainly due to the long history of liberalization in the Nordic market. But two other factors have also to be considered: firstly cross-border (or rather cross-zone) trade between different zones of the Nordic market is only possible via the Nordpool market (cf. also EU 2007). Secondly, the large share of flexible and storable hydropower provides a good basis for hedging and optimizing through the market.

Another market with high liquidity is the Spanish market. Here the volume traded at the exchange-based spot market was in 2007 about 73 % of the national consumption. Again institutional arrangements explain this high share: In the past, only electricity traded via OMEL was entitled to receive capacity payments.

By contrast, the British power exchange shows lowest liquidity (cf. EU 2007). This is in sharp contrast with the very late gate closure time, which would be expected to increase liquidity. Contrarily to the other markets investigated, the British spot market is not based on a day-ahead auction but rather on continuous trading, which may occur up to 1 hour before delivery. EU (2007) invokes as reason for the low liquidity the vertical reintegration of generation and supply businesses after the end of the former pool market. Ockenfels et al. (2008) by contrast give two different arguments, which are more related to the design of the spot market itself: in the continuous trading a pay-as-bid mechanism is applied, which reduces the price transparency of the spot market – a unique reference price for derivative trading is less easily identified under this market design than under simultaneous auctions with marginal pricing as applied in the other markets. A second reason given by Ockenfels et al. (2008) is self-reinforcement: The low liquidity and the limited transparency reduce the confidence of market participants in the power exchange and consequently their willingness to participate.

An additional argument may be put forward for day-ahead auctions: they clearly aggregate liquidity in one unique auction and avoid dispersion across single trades occurring over the whole trading period (two days in UK). This is obviously preferred by the market participants. In fact EEX offers in advance of its day-ahead auction also a continuous trading window of four hours, where at least peak and base blocks for delivery next day may be traded. Yet while trading volumes in the auctions have continuously increased, liquidity in the continuous trading has decreased. Hence market participants, if given a choice, obviously clearly opt in favor of single auctions. This observation may be at least partly explained by the planning processes in the utilities. Those traditionally have a daily planning cycle, which involves determining day-ahead the expected operation of the units. This planning process, preexisting to liberalisation, has been adapted to distinguish between the bid submission to the power exchange and then the planning given power exchange results, yet it still is applied. And the technical interdependencies in power plant operation, such as minimum operation times, start up costs or lead times make an instantaneous replanning (when a new trade arrives) difficult and/or inefficient.

Intraday markets

In times before liberalization and increasing wind power production, day-ahead plans already had to be updated in the case of new information arrival. One element of new information were plant outages, another one changes in load expectation. With liberalization one would expect markets also to be used for these replanning occasions. Another possible use of intraday markets in competitive environments is to allow for adjustment of infeasible schedules resulting from spot markets with simplified designs (linear bid curves, no block bids etc.) Indeed in Germany and other European countries there has been a move from inhouse and informal solutions for handling intraday scheduling deviations towards organized markets. Yet the market designs in these markets still strongly deviate between countries. Even within the Nordic market, which has a standardized and common spot market since the end of the 1990s, the intraday markets have remained differentiated for a long time. Even today, the intraday market ELBAS is only common to Sweden, Finland and Eastern Denmark. Also in Germany, the intraday market has only been formalized with the new Energy act of 2005. And just since September 2006, intraday trading takes place at the German power exchange EEX. A look at the traded volumes reveals even today very low volumes (cf. Table 3).

Table 3: Intraday markets in the countries considered

Country	Market Operator	Gate closure	Intraday trading volume (2007)	Share of national consumption
France	Powernext	60‘ before delivery	0.2 TWh (open since 07/11/07)	0.1 %
Germany	EEX	75’ before delivery	1.4 TWh	0.3 %
	IntradayS	Even ex-post trades	?	
Sweden, Finland, Denmark East	Nordpool	60‘ before delivery	1.6 TWh	0.3 %
Spain	OMEL	6 auctions per day	25 TWh	8 %
UK	Not relevant since spot market closes only 1 h before delivery			

A total of 1.4 TWh has been traded in 2007, this corresponds to less than 0.3 % of the total electricity consumed. In the Scandinavian ELBAS market, the market volume is with 1.6 TWh only slightly higher. These low trading volumes may be related to the market design or to the market structure. Here a closer look is required, yet this is postponed until the market design review has been completed by a look at the reserve markets.

Reserve markets

Given that electricity is not storable, the instantaneous equilibration of demand and supply has always been a core concern of Electricity System Operators. Reserves have always been used for this purpose. Even the large internationally interconnected electricity systems have been especially built up to share the burden of reserve provision among a larger number and to benefit of the (weak) law of large numbers. The largest interconnected, synchronized area in Europe is the UCTE system, which covers continental Europe from Portugal to Western Denmark and from Poland to Greece. NORDEL is the equivalent for the Nordic countries whereas UK and Ireland form separate synchronous areas. Each area is characterized by different rules for reserve. Those are primarily technical rules, which indicate how reserves are to be activated and regulated and which quantities have to be foreseen by each participating system operator. Notably the UCTE system distinguishes three reserve categories, whereas in the Nordic market only primary and secondary reserves are distinguished (cf. Table 4).

Table 4: Reserve categories in the UCTE and NORDEL systems

Reserves category, by activation type	**UCTE**	**NORDEL**
Frequency	*Primary reserve* Time for full activation max 30 s	*Primary or Frequency controlled reserve*, distinguished in • Normal operation reserve • Disturbance reserve
Automatic load flow	*Secondary reserve* (time for full activation max 5 min)	-
Manual	*Tertiary or Minute reserve* (time for full activation max. 15 min, activation duration max 1 h) *Hour reserve* (time for full activation 1 h, no provision by TSO)	*Secondary or Fast active reserves* (time for full activation max. 15 min) • Disturbance reserve • Forecast reserve • Counter trading reserve *Slow active reserves* (time for full activation more than 15 min)

How these reserves are procured, depends on the market design and varies from country to country even within one synchronous area. Even within Germany, the four TSOs used different market-designs for the purchase of the reserves. In the Nordic market, the fast active reserves are to a large extent purchased through the regulation power market.

A key difference compared to the previously discussed markets is however that the reserve markets are asymmetric by design. The demand on these markets only stems from grid operators, whereas power companies and electricity traders are solely acting on the supply side. The grid operators then use the procured reserves to provide balancing services to all grid users. These services are not sold on a separate market place but delivered to all customers according to their imbalances. Different models have been developed for the pricing of these balancing services (cf. e.g. Maupas 2008, Vandezande et al. 2008), yet these shall not be discussed in detail here.

Obviously the reserves will be used by the Transmission Operators to correct for any imbalances in real time, which have not been previously settled by the market players. As they are the last element in the supply chain, the main issues for the integration of wind energy are: how much is left at the end of the chain? And how much does society or/and wind power operators have to pay for it?

Wind power and the need for short-term adjustments

If nothing changed between the day-ahead planning and trading and the real-time operation, there would be no need for any form of short-term adjustments, the plans would just be realised as scheduled. This is also true for systems with high wind penetration, as far as changes in wind power infeed are predicted in day-ahead forecasts. Predicted changes in wind power production over the next day (e.g. strong wind in the morning, light breeze in the afternoon) lead to trading activities on the day-ahead market, where wind power producers will sell more for the morning hours and less for the afternoon hours.

Yet, as discussed above, both in the conventional system and with wind energy, there is new information arriving between day-ahead planning and real time. In the conventional system, the most important short-term informations are updates on the (expected) load *L*, e.g. due to changes in temperature or sunshine, and unforeseen plant outages *K*. For wind *W* obviously updated forecasts deliver new information. This new information may be either be based on new weather forecasts derived from meteorological models or on a statistical analysis and extrapolation of the current wind power infeed as compared to the forecasts. As discussed e.g. in Lange and Focken (2008), the latter approach is advantageous for the close future, i.e. roughly for forecast horizons below six hours, whereas meteorological models are mostly suitable for longer-term forecasts.

Adaptation to these new informations requires either short-term trading possibilities or the existence of reserves or both. For the system balance it makes no difference, whether the additional (or reduced) power is provided through intra-day trading or through pre-contracted reserves. Therefore we will in a first step just talk about short-term adjustment mechanisms in general, independently whether they consist of intraday markets or activation of reserves.

Given that all three sources of error are prima facie independent, the required total physical adjustment capacity *R* may be computed through:

$$\begin{aligned} R &= N^{-1}(\alpha)\sigma[\Delta_{tot}] \\ &= N^{-1}(\alpha)\sqrt{\sigma[L-L_F]^2+\sigma[K-K_F]^2+\sigma[W-W_F]^2} \end{aligned} \tag{1}$$

Thereby α is the required reliability level and N^{1} the inverse of the standard normal distribution, whereas the index F stands for forecasts[3].

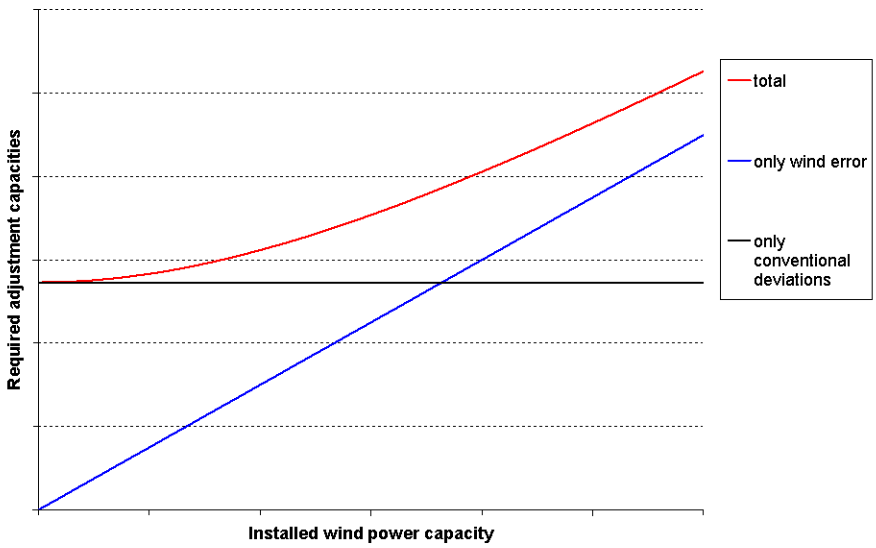

Figure 2: Physical adjustment capacities against installed wind capacities.

As illustrated by Figure 2 , the total adjustment capacities are dominated by the conventional part, as long as the installed wind power capacity is small. But with large wind power capacities, the wind forecast error gets more important and asymptotically the total error converges to the wind forecast error.

Simultaneously, the correlation $\rho_{W,tot}$ between wind and total error increases:

$$\begin{aligned} \rho_{W,tot} &= \frac{Cov[W - W_F, \Delta_{tot}]}{\sigma[W - W_F]\sigma[\Delta_{tot}]} \\ &= \frac{Var[W - W_F]}{\sigma[W - W_F]\sigma[\Delta_{tot}]} \\ &= \frac{\sigma[W - W_F]}{\sigma[\Delta_{tot}]} \end{aligned} \qquad (2)$$

This is also illustrated in Figure 3.

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[3] The formula does only hold exactly, if all three errors are normally distributed. This assumption is reasonably well satisfied for load and wind forecast errors, yet power plant outages obviously are discrete events with corresponding discrete distributions. Yet as a first approximation and for illustrative purposes the formula still is valid.

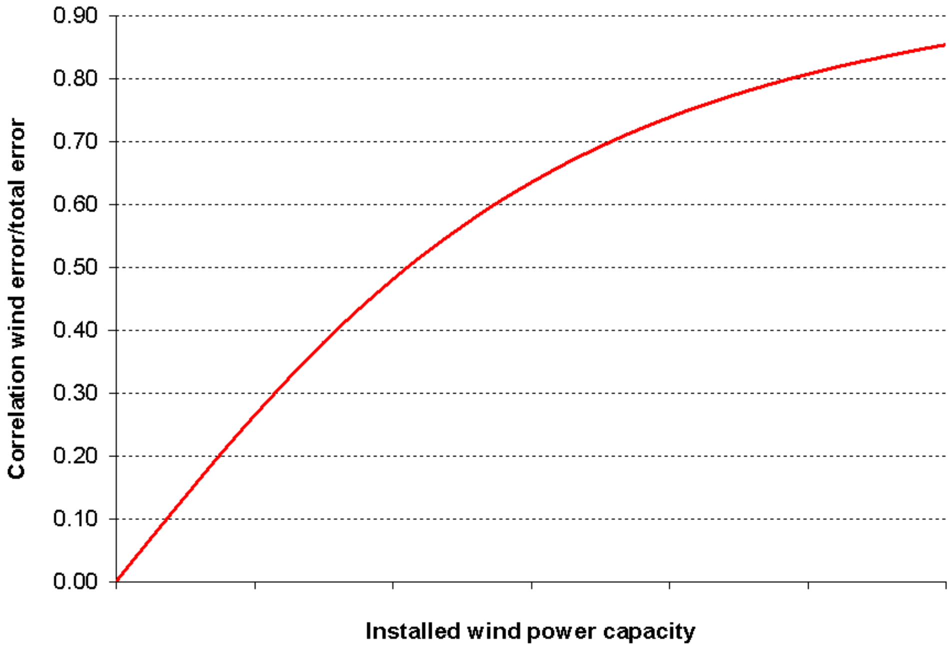

Figure 3: Correlation of wind error and total error against installed wind capacities.

Given this increasing correlation, wind energy operators will pay in any market-based short-term adjustment mechanism more for their forecast errors if the wind penetration increases. With a linear price function on the short-term market:

$$p_{adj} = p_0 + m \cdot \Delta_{tot} + \varepsilon \qquad (3)$$

these additional costs can be assessed explicitly

$$\begin{aligned} C_{adj} &= E\left[p_{adj} \cdot (W - W_F)\right] \\ &= p_0 \cdot E[W - W_F] + m \cdot E[\Delta_{tot} \cdot (W - W_F)] + E[\varepsilon \cdot (W - W_F)] \\ &= m \cdot Cov[\Delta_{tot}, (W - W_F)] \\ &= m \cdot \rho \cdot \sigma[\Delta_{tot}] \cdot \sigma[W - W_F] \\ &= m \cdot \sigma[W - W_F]^2 \end{aligned} \qquad (4)$$

Hence the adjustment costs are simply a linear function of the variance of the (absolute) wind forecast error. If the relative wind forecast error $E_{rel,Wind}$ does not change with the installed wind power capacity Cap_{Wind}[4], the variance and hence the adjustment cost will increase quadratically with the installed wind power capacity.

$$
\begin{aligned}
C_{adj} &= m \cdot \sigma[W - W_F]^2 \\
&= m \cdot \left(E_{Wind,rel} \cdot Cap_{Wind}\right)^2
\end{aligned}
\qquad (5)
$$

Moreover they linearly depend on the parameter *m*, which is the slope of the price function. This slope will be the higher the lower the liquidity in the corresponding market is (cf. e.g. Amihud 2002).

Consequently a key issue for wind integration in a market-based environment is to ensure enough short-term liquidity[5]. Whereas on the reserve markets the available bids are substantially predetermined by the reserve quantities contracted by the grid operators, the liquidity on the intraday market is not predetermined but is dependent on market structure and market design and the resulting attractiveness for the power plant operators to enter the intraday market.

From the viewpoint of a power plant operator, there is obviously a potential tradeoff between entering the intraday market and providing reserves, yet before looking at these interdependencies, the current status of liquidity is assessed on the example of the German intraday market.

Key issue: liquidity in intraday trading

The previous discussion has shown that one key issue for efficient integration of wind energy is an efficient functioning of intraday markets[6]. Figure 4 illustrates that forecast errors in wind power forecasts decrease considerably when the forecasting horizon is reduced.

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[4] For low values of installed wind capacities, geographical dispersion of wind power plants will typically increase with the number of plants installed. In that case, relative wind power forecast errors are likely to decrease with raising wind capacities. Yet for higher penetration rates, such as those reached in Germany, Denmark or Spain, this geographic dispersion effect is no longer likely to occur, since the plants are already widely distributed over the countries.

[5] Other relevant issues, notably linked to the distribution of the integration cost and the pricing of regulating power are discussed e.g. in Holtinnen (2005) and Barth, Weber and Swider (2008).

[6] As noticed by one referee, obviously also other measures may contribute to a more efficient wind integration. Also adequate rules in the balancing markets and measures to reduce market power in these markets will be important.

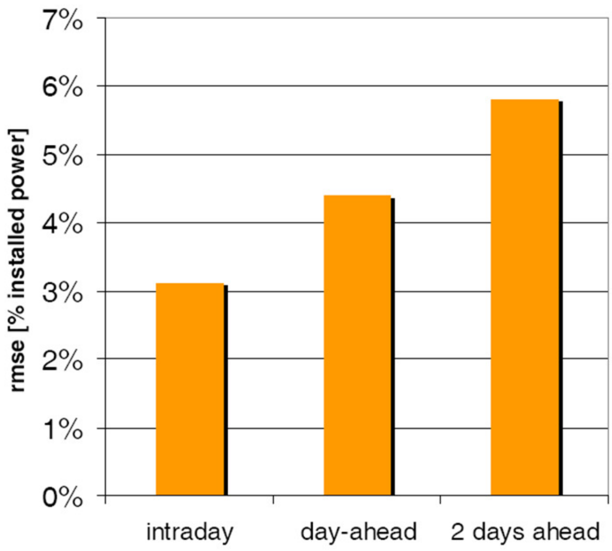

Figure 4: forecast errors on different markets.

One has however to be aware that the prediction error is reported here relative to the installed power and not the actual average power production. Given that German wind power turbines have on average 1600 full load hours, the day-ahead prediction error is more than 20 % of the average production.

This error may be reduced by making use of intraday forecasts, yet the reduction is not linear (cf. Figure 4). Nevertheless the use of information closer to actual delivery will be beneficial.

Hence market design should facilitate an efficient use of this information. In principle, several alternative routes may thereby pursued:

- ensure functioning intraday markets,
- allow for intraday and even real-time internal portfolio optimization within large producers
- move the entire gate closure time for the spot market closer to delivery and trading then on the spot market[7].

Since the second alternative raises concerns on market power and the third seems not likely to provide liquidity as shown above in section 2, the focus in the following is on the intraday markets. Here in a first step for the case of Germany the physical needs for intraday trading are assessed. Those are then compared to the observed trading volumes and the discrepancies are interpreted.

[7] As noted by one reviewer, this would ultimately lead to the disparition of the (separate) intraday market.

Needs for intraday trading

As discussed in section 3, three major sources for deviations between day-ahead plans and actual delivery have to be considered in energy systems with high wind penetration:

- Load forecast deviations
- Power plant outages
- Wind forecast deviations.

Since all these are physical or technical phenomena accessible to statistical measurement, the total market volume resulting from these sources may be assessed. This is done in the following for the case of Germany (cf. also Pack 2007), starting with wind energy, which is the prime focus here.

For wind power, both the day-ahead predictions and the actual (estimated) production are now regularly published by the German TSOs. Based on data from 2006 and 2007, the mean absolute deviation (MAE) is estimated at 600 MW, which is also in line with the above given values – considering that there are about 20,000 MW installed wind power capacity in Germany and that the MAE is lower than the RSME (root mean square error).

For load forecasts, an average forecast error of 2 % in day-ahead forecasts (cf. Hufendiek 2001) provides a total potential of around 1200 MW of aggregate intraday load deviations within Germany[8]. This shows, that despite already high wind penetration in Germany, the load forecast error is still dominating the wind forecast error by about a factor of 2. And under the assumption of stochastical independence of the two forecast errors, additional wind forecast errors increase the required trading or/and reserve volume currently only by less than 50 %[9]. Yet this will change with a further increase in installed wind capacities.

The potential for intraday trading resulting from power plant outages is determined by the number of outages per block and year and the duration of these outages. With about 20 outages per unit and year for fossil-fired units[10] and an average duration of 10 h we get for Germany an expected volume of 1700 MW. Given that the electricity for the first hour of an

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[8] Maupas (2008) indicates even a forecast error below 1 % for the French system.
[9] This is an upper bound derived from equation (1) by determining the marginal change in reserves for an increase in Wind forecast error $E_{Wind}=N^{-1}(\alpha)\sigma(W-W_F)$:

$$\frac{\partial R}{\partial E_{Wind}} = \frac{N^{-1}(\alpha)}{2\sqrt{\sigma[L-L_F]^2+\sigma[K-K_F]^2+\sigma[W-W_F]^2}}\left(\frac{2\sigma[W-W_F]}{N^{-1}(\alpha)}\right)$$
$$= \frac{E_{Wind}}{R}$$

In the numerical approximation, the power plant outages are neglected for the moment and the previously mentioned figures for wind and load forecast errors are inserted.
[10] This figure is given by VGB Powertech (2007) based on statistics for numerous conventional power plants in Germany and Europe,

outage cannot be procured at the intraday market and due to a rather skewed distribution of outage durations, it is expected that the actual level is rather on average around 1400 MW.

Observed intraday trading

Using the relation (1), the potentials for intraday trading mentioned in the previous section may be added up quadratically. This yields a daily trading volume with a standard deviation of more than 2000 MW, corresponding to more than 17 TWh trading volume per year. This is far beyond the 1.6 TWh observed in the German power exchange in 2007. Even if OTC trades, including the specialized Internet platform named IntradayS, are taken into account, a strong discrepancy between the physically expected trading and actual figures appear.

Reasons for discrepancy

Besides transaction costs and potential trade-offs with the balancing markets (cf. below), a major reason for the discrepancy certainly is the market concentration in the power market. The large producers and suppliers will at least partly find it more advantageous to do a netting of intraday open positions within their own portfolio instead of going through the power exchange[11]. Since similar arguments apply for spot trading, the share of 22 % of physical volume reached in the spot market (cf. Table 2) may be taken as a first guess on the relevance of this factor. Applying this percentage to the total estimated volume of 17 TWh (cf. section 4.2), a realizable market volume of about 4 TWh is derived, which is still far beyond the actual trading. Partly the lack in liquidity may certainly be interpreted as a temporary effect and autonomous increases may be expected in the future. Yet it is questionable whether this alone will be sufficient and alternatives have to be considered. In particular market participants often complain that there are very little opportunities to purchase power in the case of unforeseen events.

Interaction with the reserve markets

So far, the focus of the analysis has been on the intraday market as a short-term opportunity for wind power producers to compensate for their forecast errors[12]. Obviously the alternative is not to compensate the errors through market transactions but rather to use balancing energy provided by the system operator. On the supply side, bidding into the reserve market clearly is a substitute for the power plant owners to short-term sales of power on the spot and intraday

[11] In Germany, this is especially true for the four large power producers RWE, E.ON, Vattenfall and EnBW, who control about 80 % of the total conventional power plant capacities. Ownership for wind power production is far less concentrated. Moreover wind power producers are under the current legal framework not obliged to ensure balancing for their production.

[12] In some markets, notably in Germany and previously in Spain, the wind power producers themselves are not responsible for the deviations between scheduled and actual wind power infeed. Rather it is the responsibility of the grid operator to handle these deviations. However this does not change substantially the subsequent reasoning, since it is focusing on the incentives for the "Balancing Responsible Party", i. e. the entity in charge of handling wind power forecast errors, be it the wind power producers themselves or the grid operator.

markets (cf. also Maupas 2008, Just and Weber, 2008). Hence the two markets are closely interlinked. From a market design perspective, the two markets and their interaction should thus be designed in a way to provide incentives to all market participants for achieving globally efficient market results. Yet a proposal for an optimal design is beyond the scope of this paper, since it requires the consideration of short- and long-term incentives to all market participants, not only to wind power producers but also to conventional producers, traders, consumers and grid operators. Nevertheless, a few key requirements in view of improved wind integration are discussed in the following.

Given that reserves are even more flexible than quantities sold on the intraday market, their provision should be more complicated and their price should in principle be higher than the price of intraday energy. Hence the wind power producers should have clear incentives to avoid use of reserves whereas the power producers would bid flexible units first into the reserve markets. Only those units not accepted in the reserve market or not capable of delivering reserves would consequently be offered in the intraday market, reducing somewhat the liquidity in this market segment. Nevertheless, enough capacities should be available for the intraday market except for some peak hours.

This simple relationship may however be disturbed if the bids on the reserve markets consist of a capacity and an energy bid, as it is notably the case in Germany. Given that they earn a capacity revenue, power plant operators may then offer lower energy prices on the reserve markets than on the intraday market. If the TSOs use those prices for pricing balancing energy, situations may occur, where the balancing energy price is lower than the intraday market price. This obviously creates distorting incentives for wind power producers and other balance responsible entities[13] – independently whether they are under a uniform balancing price or under a two-price model[14]. This kind of inconsistent incentives particularly occurs, when the reserve power is not procured simultaneously with the spot electricity, as is again the case in Germany. In this case, an additional rule should ensure that prices for positive balancing energy do not undercut spot prices. This would clearly avoid the gaming incentives discussed by Wawer (2007).

Another kind of problem occurs in Denmark and the other Scandinavian countries, where the liquidity of the intraday market is also low. This is at least partly related to the fact, that producers can submit bids in unlimited quantities for the so-called balancing power market. Those bids do not receive a capacity price, yet they are included in the short-term merit order list of the grid operators and activated if economically attractive. However this system is not as problematic as it may seem: given the high share of hydro, flexible power capacity usually is not scarce in the Nordic power system. Consequently differences between day-ahead (or

[13] Cf. also the work by Wawer (2007) on the distorting effects of the German pricing mechanisms for balancing energy.

[14] On the advantages of uniform balancing prices as compared to two-price models see Barth et al. (2008)

intraday) power prices and the balancing power prices are low. This implies that wind operators (provided they see a uniform balancing price) do not incur large losses, if their deviations are settled using balancing energy instead of intraday trade. More problematic is here that all Scandinavian countries except Norway use two-price models when it comes to charging the balancing energy.

The results of Maupas (2008) suggest that it is economically most efficient not to have an intraday market and a balancing energy mechanism in parallel but to rely solely on the balancing energy / reserve markets. The main explanation is that the doubling of markets leads to inefficient planning with the TSO, because he has to adapt to changing trades and plans of the individual operators. Yet Maupas (2008) also clearly indicates that the quantities dealt with in this case by the balancing energy mechanism may get very large. Moreover this market design may facilitate the abuse of market power, given that in many countries only a few companies are dominating the electricity business.

Key challenge: Improved intraday market functioning

In this situation, four principal alternatives may be envisaged to improve the functioning of the intraday market and thus ease the integration of wind energy:

- Change from day-ahead spot auction to continuous spot trading until close to physical gate closure
- Move gate closure time for the spot auction e.g. to 6 p.m. on the day before
- Bundling of liquidity by introducing auctions in the intraday market
- Increase of liquidity by obliging market partners to bid into the intraday market

The intention of all these measures is to facilitate the intraday adjustment for wind power producers and thus to lower the adjustment cost.

Yet the first alternative seems to be not very attractive given the British experience. The even more radical step from an exchange based to a pool based system like PJM is currently hardly conceivable, given that this would require a strong pan-European or at least international ISO.

The second alternative would certainly provide some improvement, yet is not very compatible with the usual office hours and would hence at least induce some additional transaction costs for increased staff presence etc. Moreover the fundamental problem of how dealing with deviations within the day itself is not solved.

The third alternative corresponds to the actual market design of the Spanish and now also Portuguese market. There six auctions during the day of delivery itself are carried out. The total market volume is 25 TWh and thus considerably above the volumes observed in the other markets. Also the distribution of purchases and sales corresponds to the theoretical considerations made above. Almost 75 % of all purchases are done by producing units – presumably to compensate for outages. On the sales side even more than 90 % of the bids stem from producing units – the consuming units apparently on average underestimate their needs and tend to act as net purchaser in the intraday market. Such a revised market design would certainly induce some additional operational costs (for new IT systems, staff etc.), yet overall transaction costs are almost certainly lower, since the price risk for trading on the intraday market is lowered.

The fourth alternative is problematic given that it would impose constraints on the economic activities of the market participants. Yet at least in one point this would be beneficial for liquidity and also economically sound: so far in Germany, the TSOs have to handle the forecast deviations for wind energy. Since they have not much trading competence by themselves, they tend to outsource this activity and frequently they buy the portfolio management services from the trading company within the same holding. Those traders usually compensate the wind fluctuations with other fluctuations in their portfolio and consequently only put limited amounts for purchase at the stock exchange. By separating these diverse activities, obviously liquidity should be increased, even if in the short to medium run the quantitative impact will remain limited.

Final remarks

The discussion has shown that wind energy will particularly benefit from increased liquidity in the intraday markets – at least once the current status is lifted, where wind power operators in Germany and elsewhere are not responsible for the schedule deviations, which they are causing. Among the possibilities considered here, the organization of intraday auctions as done in Spain seems to be the most attractive way for increasing liquidity. Yet one has to be careful not to provide inconsistent incentives and gambling opportunities for traders active both in the day-ahead and the various intraday auctions. Also more research is needed to assess the optimal combination of intraday and reserve market designs. Several approaches may be envisaged to address this issue: equilibrium analysis in the vein of Just and Weber (2008) to determine price and quantity patterns in a perfect competition setting, game theoretical modeling to assess potential incentives for excersing market power or simulation studies in the line of Maupas (2008) to investigate possible market outcomes and costs.

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3 Impacts of intra-day rescheduling of unit commitment and cross border exchange on operational costs in European power systems

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Abstract-- The Wilmar Planning tool was used to study market rule parameters directly influencing the functioning of the internal European electricity market. These parameters are the efficiency of the cross-border allocation mechanism (spatial dimension) and the flexibility in time that is offered by the markets (time dimension). Simulations were carried out for a European power system covering 31 countries in 2015 characterized by installed wind power capacity, electricity demand, available interconnector capacity and energy economic boundary conditions. Four model runs were carried out investigating the consequences of having different degrees of market integration between countries and having different amounts of well functioning intra-day power markets for the operation of the European power market in terms of system costs and CO2 emissions. Model results show significant system cost increases connected with fixing unit commitment of slow units and cross-border exchange day-ahead. Cross-border exchange of reserves induced very small costs savings due to model limitations.

Index Terms—Market design, power exchange, unit commitment

Introduction

OVer the last decade, electricity markets all over Europe have developed and expanded in number and traded volumes. Going along with these developments, also cross-border trade has gained in importance and rules for cross-border power trades and allocation of corresponding capacities have been repeatedly under scrutiny (e.g. [1] [2]). From traditional long-term allocation mechanisms, rules have evolved towards market-based allocation using implicit or at least explicit methods (cf. e.g. [3] [4]). In parallel to these international developments, also national markets have increased in flexibility by the introduction of competitive intraday and balancing markets. There has been a number of theoretical papers on adequate design of these markets (e. g. [5], [6]), yet so far little empirical evidence exists at the European scale on the impact of different market designs on the overall system costs. In particular it has been claimed that introducing balancing markets at the European level will strongly support integration of wind energy [7]. Therefore the present contribution investigates the impact of increases in flexibility on the intraday market. Thereby both improved rescheduling within one country and across borders are considered and the effects are assessed using a large scale model of the European power system designed to analyse wind integration. This so-called Wilmar Planning tool includes notably an explicit representation of day-ahead and intraday markets. Moreover the flexibility of individual power plants or groups of power plants may be modified using specific parameter settings. Therefore this model is particularly well suited to assess the impact of changes in market design.

The remaining of the paper is organized as follows: In Section II the Wilmar Planning tool is presented. Section III presents the model runs representing different market rule scenarios, and Section IV the power system analysed. Results are given in Section V and Section VI concludes.

Model

The Wilmar Planning Tool is used to analyse the consequences of different market rules for the operation of a future European power system. The main functionality of the Wilmar Planning tool is embedded in the Scenario Tree Tool (STT) and the Scheduling model (SM).

The Scheduling model

Assuming perfect markets i.e. least cost dispatch and full information sharing among all actors, the SM models the following markets:

- A day-ahead market for physical delivery of electricity. This market is cleared at 12 o'clock for the following day using day-ahead point forecasts for the hourly wind power production and load.
- An intra-day market for handling deviations between production agreed upon the day-ahead market and the required redispatch due to updated wind power production and load forecasts and occurrence of forced outages.
- A day-ahead market for positive and negative spinning reserve power. The demand for these reserves is determined exogenously to the model.
- An intra-day market for positive reserve power needed to cover more extreme forecast errors. The demand for this type of reserve named replacement reserve is dependant on the

forecast horizon, and determined by the distributions of total forecast errors as calculated by the STT (see below).

- Due to the interactions of CHP plants with the day-ahead and the intra-day market, intra-day markets for district heating and process heat are also included in model. The heat demand is given exogenously.

The SM optimises unit commitment and dispatch of power plants, heat production units and storage units and power exchange between model regions, while satisfying the demands on all these markets. The model minimises the value of the system operation costs consisting of fuel costs, start-up costs, costs of consuming CO2 emission permits and variable operation and maintenance costs. *The SM is originally designed to handle multiple wind power and load forecasts using scenario trees [8; 9; 10]. Due to the size of the power system modelled in this paper encompassing 31 countries, only one wind power production forecast and load forecast could be used in each optimisation loop in the model due to calculation time restrictions. Hence in this paper scenario trees with only one branch is used.*

Hydropower with reservoir in principle requires a planning horizon of a year or more in order to distribute the hydro inflow optimally across the year. The model simplifies this decision problem using a historical time series for the optimal hydro reservoir level in each region during the year. The model reduces the production costs of hydro power when the reservoir level in the model becomes higher than the historical optimal level and the opposite when the reservoir level becomes lower than the historical level. This ensures that the historical optimal reservoir level during the year is followed closely in the model.

The transmission network is represented by splitting the geographical area modeled into a number of regions, with each region containing a number of production and storage units and having scenario trees of load forecasts, wind power production forecasts and demand for replacement reserves. The regions are connected by transmission lines described by a transmission capacity and an average loss. The grid within each region is only taken into account as an average distribution loss. District heating areas can be defined in regions where combined heat and power plants have a significant role in the power system. An area is characterized by an hourly heat demand time series, and a portfolio of conventional and CHP power plants, heat boilers and heat storages.

The Scenario Tree Tool

The Scenario Tree Tool generates scenario trees for replacement reserves, wind power production forecasts and load forecasts. It also produces hourly time series of forced outages of unit groups. The main input data for the Scenario Tree Tool is wind speed and/or wind power production data, historical electricity demand data, assumptions about wind production forecast accuracies and load forecast accuracies for different forecast horizons, and data of forced outage rates and the mean time to repair of power plants.

Generation of wind speed and load forecast errors is based on an ARMA approach, i.e. Auto Regressive Moving Average series. The parameters of the ARMA series are estimated by comparing the standard deviations of the ARMA series with empiric standard deviations of historic hourly forecast errors. The optimal ARMA parameters are then found as those values that minimize the difference between the two sets of standard deviations. The optimal ARMA parameters are used in the STT to generate sets of wind speed and load forecast error scenarios by Monte-Carlo simulations. These forecast errors are then added to historical data for wind power production and load time series to form wind power production and load forecast scenarios. The Monte-Carlo simulations give rise to a large number of load scenarios. Hence, a scenario reduction algorithm follows the scenario generation. For further reference, see [10] and references therein. By construction, the scenario reduction tends to remove extreme scenarios. However, as extreme scenarios potentially have a significant impact on the need for reserves, replacement reserves are introduced to ensure enough online or fast starting capacity to cover extreme forecast errors.

The demand for replacement reserves corresponds to the total forecast error of the power system considered which is defined according to the hourly distribution of wind power and load forecast errors and according to forced outages of conventional power plants. Thereby it is assumed that the nth percentile of the total forecast error has to be covered by replacement reserves.

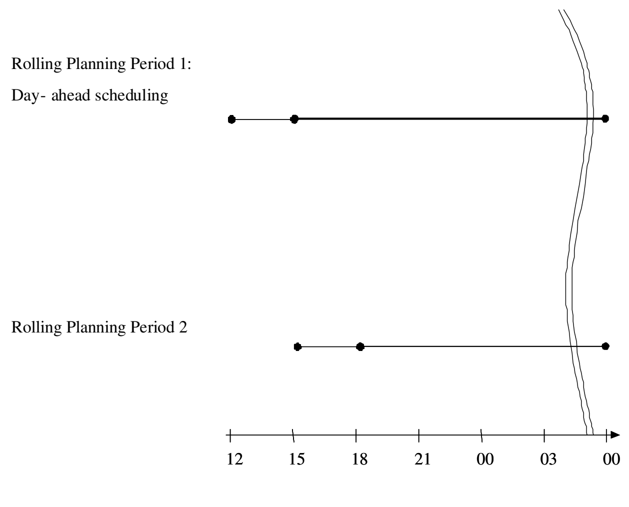

Fig. 5. Illustration of the rolling planning and the decision structure in each planning period.

Rolling planning

As it is not possible to cover the whole simulated time period with only one optimization period the model steps forward in time using rolling planning with a three hour step. The decision structure is illustrated in Fig. 5 showing the scenario tree for two planning periods. The first planning period covers the hours from 12.00 in day one to 24.00 in day two i.e. 36 hours. The next planning period step forward in time with 3 hours, i.e. starts at 15.00 day one and still ends at 24.00 in day two, and likewise with the next 6 planning periods. After eight planning loops a new day-cycle begins. For each planning period a deterministic optimization problem is solved having perfect foresight the first 3 hours, and point forecasts in subsequent hours. Hence, the scenario tree represents a decision structure where the system operator performs unit commitment and dispatch assuming perfect knowledge about the realized wind and load in the first three hours, and having hourly point forecasts of wind power production and load in subsequent hours. Every three hour, there is the possibility to change the planned unit commitment and dispatch and power exchange for future hours within the limits provided by start-up times, minimum operation times and minimum shut-down times as a response to receiving updated information about the status of the power system as the operation hours in question gets closer in time. The first three hour represent the realized system operation, and following hours represent planning into the future. It is the realized system operation that is saved and reported in the Results section. The perfect foresight assumption for the first three hours is necessary for the model, but to get a realistic unit commitment, the wind and load forecast errors within the first three hours contribute to the demand for replacement reserves in the first three hours.

Market rule scenarios

Four different cases investigate the consequences of having different degrees of market integration between countries and having different amounts of well functioning intra-day power markets for the operation of the European power market in terms of system costs (see Fig. 2):

AllDay: Unit commitment for slow units and cross border exchange determined day-ahead (12-36 hours ahead) and not rescheduled intra-day. The dispatch (production levels) of the committed units can be changed intra-day subject to the minimum and maximum operation levels. No exchange of replacement reserves across borders. Slow units are units with a start-up time of one hour or more, i.e. all units except hydropower with reservoir, pumped hydro storage, open cycle gas turbines, and units using light oil or fuel oil.

ExDay: Like AllDay except for unit commitment for slow units now being rescheduled intra-day. Cross-border exchange is still allowed day-ahead only.

AllInt: Like ExDay but cross border exchange allowed to be rescheduled intra-day.

AllIntExRes: Like AllInt but exchange of replacement reserves across borders allowed, i.e. part of the demand for replacement reserves can be provided by a neighbouring country by reserving part of the cross-border transfer capacity for this purpose.

All cases use day-ahead forecasts of wind power production and load and updated wind and load forecasts when rescheduling every three hour, but in different ways. In AllDay the updated forecasts are not allowed to influence the unit commitment decisions of slow units and the cross border exchange planned using the day-ahead forecasts, because rescheduling of these decisions are not allowed. Likewise in ExDay the cross border exchange is not rescheduled due to updated wind and load forecasts.

AllDay is an extreme scenario modelling a power market with very inflexible market rules, and very badly functioning intra-day markets. Both unit commitment for slow units and cross-border exchange are determined day-ahead creating problems with handling the deviations between day-ahead production plans and real-time operation created by the day-ahead forecasts errors of load and wind power production. In ExDay replanning of day-ahead unit commitment decisions is possible, i.e. either well-functioning national intra-day power markets are in place or the TSO do the rescheduling. Still usage of cross-national transmission lines is fixed day-ahead and exchange of reserves across borders is impossible. In AllInt the countries cooperate in covering deviations between day-ahead production plans and real-time operation by allowing the cross-border power exchanges to be rescheduled intra-day. Finally in AllIntExRes even replacement reserves (minute to hour reserves) can be exchanged across borders.

The four model runs share exactly the same assumptions concerning production costs, power plant capabilities, installed capacities, etc corresponding to year 2015. They only deviate in the assumptions concerning the possibilities for intra-day rescheduling of unit commitment and power exchange, and the ability to share reserves across borders.

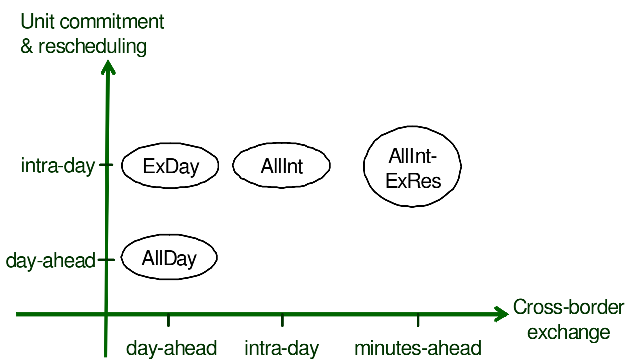

Fig. 6. *Overview market rule scenarios.*

Application case

31 countries consisting of EU27 except Malta and Cyprus and including Norway, Switzerland, Macedonia, Serbia, Bosnia and Albania are included in the model runs. Fig. 3 shows these countries marked in grey.

Each country is represented by one region except for Denmark being split into two regions Denmark West and Denmark East. Thereby only capacity limits in the transmission lines between countries are included, and the transmission grid within countries does not influence results. As calculation times are long and memory usage high for such a large geographical case, it was not possible to include a more detailed representation of the power grid.

Fig. 7. Considered European countries marked in grey.

TABLE I

DATA AND APPLIED SOURCES

Data on	Source	Resolution
Fuel & CO_2 prices	IEA	Yearly
Load profiles	ENTSO-E	Hourly
Annual load	ENTSO-E	Yearly
Wind power generation	Tradewind project/	Hourly
RES-E deployment (excl. wind power)	Green-X	Yearly
Hydro inflow	Marketskraft /	Hourly / yearly

	national statistics	
Reservoir levels	Marketskraft / national statistics	Seasonal
Conventional power plants	Platts database/ own research	Single plant
Technical parameters	Academic literature	Single plant
Heat load	National statistics	Hourly
Grid data	ENTSO-E	Yearly

The model is coupled to a database, which has detailed information on the European power system. The sources of most important data are summarized in Table I.

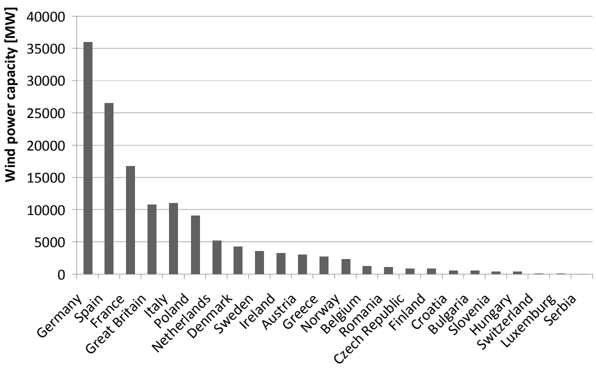

Fig. 8. Assumed wind power capacities in European countries 0.

For the creation of wind power production forecasts, load forecasts and forecasts of replacement reserves, measured wind power time series for 2006 for some of the investigated countries (Austria, Denmark, Germany, Ireland, Spain) were used, and for the rest of the countries modelled wind power time series developed within the TradeWind project was used 0. The wind data is combined with hourly historical load data and assumptions about load forecast and wind power production forecast errors for forecast horizons 1-36 hours ahead, and with scenarios of installed wind power capacity in each country in 2015 0, 0, see Fig. 4. Renewable capacities excluding wind are derived with help of the Green-X tool based on a database that combines promotion policies for renewables and potentials of renewables in Europe 0.

The database with power plants contains approximately 31000 units, so aggregation of units into unit groups according to plant type, fuel type and vintage of plants is necessary. Hence the European power plant portfolio is represented by 807 unit groups. Due to the very aggregated representation of units, a linear representation of the unit commitment decision of unit groups is sensible, i.e. any fraction of the installed capacity of a unit group can be brought online, in contrast to a binary representation where either zero or all capacity can be brought online.

Price of tradable CO2 emission certificates used in model runs was 46 EUR/tons CO2. For a more detailed description of the data see 0.

Results

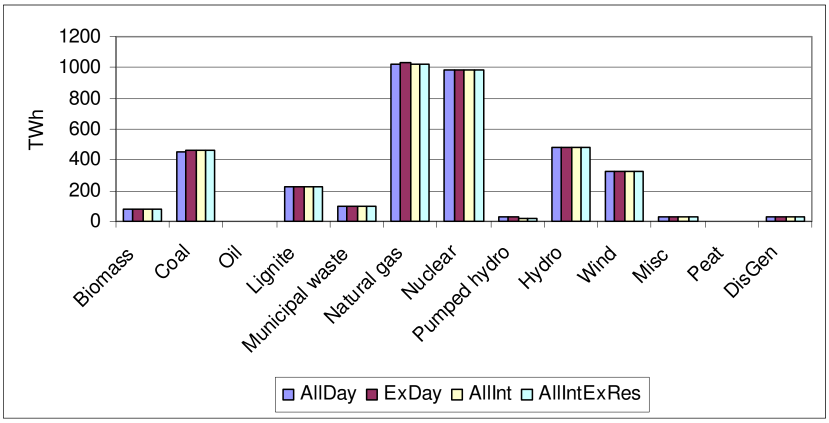

Fig. 9. Yearly electricity production distributed on fuels in 2015 for all cases.

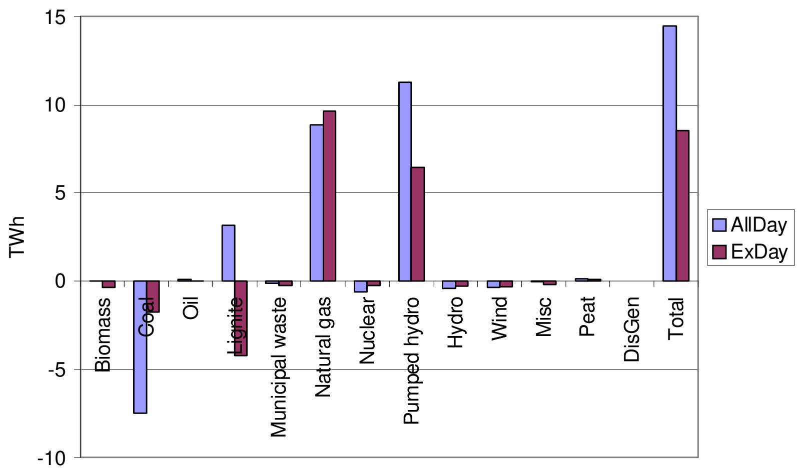

Fig. 10. Differences in yearly electricity production in AllDay and ExDay relatively to AllInt.

Fig. 5. shows the yearly electricity production distributed on fuels for all cases. 8.7% of the electricity production comes from wind power. Natural gas and nuclear based power production dominate due to the relatively high CO2 price assumed. There is not much difference between cases as should be expected in that the cases only differ with regard to intra-day scheduling of unit commitment and cross border exchange. Still subtracting AllInt from AllDay and ExDay reveals that the increased flexibility in AllInt leads to less power production on natural gas plants and pumped hydro storage plants, see Fig. 6.

TABLE II
YEARLY OPERATIONAL COSTS OF POWER GENERATION IN 2015 FOR ALL CASES IN MEUR.

	Total operational cost	Relatively to AllInt	Difference relatively to AllInt
AllDay	114026	1.010	1159
ExDay	113659	1.007	791
AllInt	112867	1.000	0
AllIntExRes	112867	1.000	-1

TABLE III
YEARLY AMOUNTS OF LOAD SHEDDING AND NOT FULFILLED DEMAND FOR REPLACEMENT RESERVES, VALUE OF LOST LOAD, COSTS OF NOT MEETING REPLACEMENT RESERVE TARGETS IN 2015.

	Reduced load [TWh]	Demand for replacement reserves not met [TWh]	Value reduced load [MEUR]	Value replacement reserve not met [MEUR]
AllDay	0.657	0.052	1970	15
ExDay	0.139	0.239	418	72
AllInt	0.010	0.014	31	4
AllIntExRes	0.010	0.014	30	4

Table II shows the total operational costs of the four cases. Allowing for rescheduling of unit commitment saves 367 MEUR (difference between AllDay and ExDay) and rescheduling of cross-border exchange a further 791 MEUR (difference between ExDay and AllInt). These are significant values although only in the order of 1% of total system operational costs. Operational cost savings of allowing for cross-border exchange of replacement reserves are negligible. Replacement reserves are in many hours, although not in all countries, provided by offline fast-starting fuel oil and light oil units. These units would anyhow in many hours be offline, so the operational costs (excluding investment cost) of providing replacement reserves with these units are often zero. Improved modeling including the capital costs of having these units available in the power system would increase the value of providing replacement reserves across borders.

Amounts of load shedding and not meeting replacement reserve targets are significantly higher in especially AllDay but also in ExDay relatively to AllInt and AllIntExRes, see table III. Using a value of lost load (VOLL)of 3000 EUR/MWh and a value of not meeting replacement reserves of 300 EUR/MWh, table III shows the costs associated with load shedding and not meeting reserve targets. Load shedding costs are significant when compared to savings in total operational costs, although results are indicative as there is high uncertainty connected to the correct value of the VOLL.

Conclusions

The AllDay case illustrates the importance of intra-day rescheduling of unit commitment of slow units with start-up times of 1 hour or more for reducing load shedding. As unit commitment rescheduling will certainly take place if the alternative is load shedding, this case is extreme and serves to emphasize the importance of flexibility in unit commitment decisions for system security.

Allowing for intra-day rescheduling of cross border exchange will lead to savings in operational costs of power generation of approximately 1%, or in the order of €0.8 billion per year compared to day-ahead cross-border exchange. Cost savings are due to decreased usage of flexible but relatively expensive natural gas and pumped hydro storage power plants when intra-day rescheduling of cross-border exchange is allowed.

The cross-border exchange of reserves has no effect on the operational costs of power generation. Nevertheless, cross-border exchange of reserves may lead to a decrease in investment costs for reserve capacity by making existing capacity available across borders.

In conclusion, the establishment of intra-day markets for cross-border trade is key for market efficiency in Europe.

Acknowledgements

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4 Load flow based market coupling with large-scale wind power in Europe

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Abstract-- With the anticipated increase of international electricity trade between European countries and of intermittent wind power generation in the upcoming years, the international exchange of electricity is expected to grow as well. In order to account for the divergence between commercial transactions and physical load flows and to efficiently exploit available interconnector capacities, load-flow based market coupling of national electricity markets is discussed. In this paper, European-wide load-flow based market coupling on the day-ahead market is analysed by the use of a fundamental optimisation model that derives the optimal electricity market operation taking into account the chronological sequence of several markets. By comparison of day-ahead market operation without market coupling, the effects on system operation costs, electricity prices and power system operation are discussed. With load-flow based market coupling, the average annual electricity price and overall system operation costs are decreased. Yet these impacts cannot be generalized for all countries.

Index Terms--**Electricity prices, international electricity exchange, load-flow based market coupling, electricity market model, system operation costs, wind power generation**

Introduction

In recent years European electricity markets have been liberalized and trading of electricity has become a major driver for converging of power markets. Within Europe there exist manifold national power exchanges with different market designs regarding national and international trading. Most markets are physically linked via so called cross-border interconnectors between the national extra high voltage transmission grids. Until now, for many European borders, available interconnection capacity is auctioned separately from electricity trade by explicit auctions [1]. Traders bid for parts of the interconnectors' capacity and are subsequently allowed to use obtained capacities for their own commercial trading. The so called net transfer capacities (NTC) accessible for trading do not cover the total thermal capacities (TTC) at a border, because they consider the maximal exchange capability between two countries compatible with security standards applicable in both countries and taking into account the technical uncertainties on network conditions [2]. NTC are allocated in different time frames to match the need for securing longer term trading and to provide room for shorter term trading. These NTC values are repeatedly derived with detailed nodal load-flow models, based on information of the two countries' involved transmission system operators (TSOs).

After trading of electricity, the dispatch of generation assets is planned, so that every commercial agent is able to fulfil its contracts. Due to the laws of Ohm and Kirchhoff, however, meshed networks show no correspondence of the commercially planned transactions and the physical flows for most patterns of injections and withdrawal. In Fig. 1 it is exemplarily shown how 1 GW of additional generation in Northern France exported to Italy is affecting the physical power flows on the central European borders. As a consequence, the TSOs have to adapt market operations in order to sustain system security and feasibility of coping with a certain demand and generation situation. Hereby, the TSOs modify the market outcome of dispatch and flows in a way that is feasible from a technical perspective.

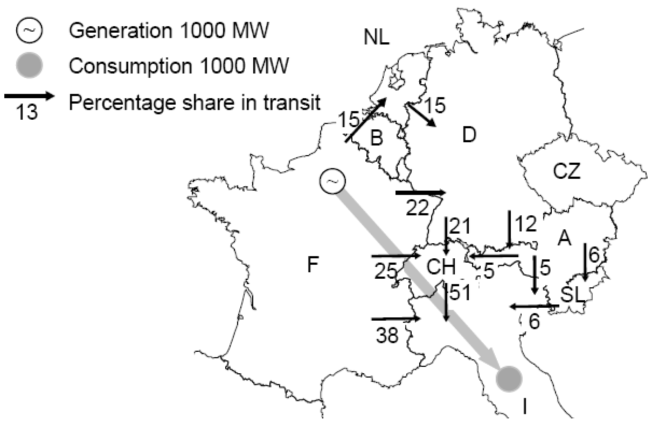

Fig. 1. Exemplary distribution of an scheduled export from Northern France to Italy on individual cross-border lines between neighbouring countries [2].

A further reason increasingly influencing the flows within the European power system is the rising share of RES-E generation, most notably from wind turbines, which further affect the planning of power flows between national electricity markets. This is due to the intermittent and not fully predictable behaviour of wind power. Depending on the wind power generation in different countries and at a certain hour, it may contribute to international cross-border congestions. Thus, the TSOs have to interfere more often into the power market in order to simultaneously adapt dispatch and scheduled flows to physical limits and wind power realisations. This redispatch of the TSO might lead to additional system operation costs due to an increasing requirement on the power plant flexibilities. Moreover, available interconnector capacities may not be optimally utilized by non-consideration of grid related constraints. Hence, an improved coordination of international electricity trade may lead to decreased system operation costs and electricity prices.

As improved trading mechanism between national electricity markets considering the physical grid operation, the so called load-flow based market coupling is discussed. Market coupling can be implemented in manifold ways depending on the market designs in place and the quantity of considered countries, but basically it means that implicit auctions of the interconnectors are established, see for example [1], [4]. One current example of market coupling is the Pentalateral Energy Forum in Central Western Europe. With load-flow based market coupling, the impact of trading operations on the distribution of load flows is already taken into account during the market clearing process. The load-flow based coupling of electricity markets has theoretically the following advantages:

- usage of cross-border capacities is optimized
- the level of congestion on borders is reduced
- redispatch costs due to deviations of scheduled planning are reduced
- competition in an integrated market is increased.

In the following, the effects of market coupling with large-scale wind power generation in Europe are assessed. In doing so, a zonal electricity market model of the European countries is applied. Section II. starts with a description of the applied model and its' innovative capability in deriving redispatch costs due to deviations in scheduled and physical flows. In the subsequent chapter III., the investigated scenario for the analysis are presented. The results of the calculations obtained are discussed in section IV. Section V. finalizes the paper giving conclusions.

The Model

The applied model is based on the Wilmar Planning Tool as further described in [6]-[8]. The Wilmar Planning Tool describes electricity markets based on an hourly description of generation, transmission and demand and it derives hourly electricity market prices from marginal system operation costs. This is done on the basis of a least-cost optimisation of the unit commitment and dispatch taking into account the trading activities of the different actors on the considered energy markets. In this model four electricity markets and one market for heat are included:

- A day-ahead market for physical delivery of electricity. This market is cleared at 12 o'clock for the following day taking the nominal electricity demand as given exogenously. Optionally, a description of the physical load flow between European countries can be considered for determining the cost optimal market clearing with load-flow based market coupling.
- An intra-day market for handling deviations between production agreed upon the day-ahead market and the required redispatch in the actual operation hour in order to fulfil the restrictions of the international physical load flow between European countries. Hence, the electrical load flow restrictions between European countries are taken into account.
- A day-ahead market for spinning reserve power. The demand for these reserves is determined exogenously to the model.
- An intra-day market for positive secondary reserve power (minute reserve). The demand for this market is given exogenously to the model.
- Due to the interactions of CHP plants with the day-ahead and the intra-day market, intra-day markets for district heating and process heat are also included in model. The heat demand is given

exogenously.

It is key not to look only individually at these markets. Rather a repeated, rolling planning has to be applied, which reflects market structures in reality and that rescheduling may occur in order to consider international load flow restrictions. With current market rules for example in Scandinavia and Germany, the spot market for the successive day is cleared at noon taking into account day-ahead forecasts of wind and load. According to this, the daily planning cycle of the model starts at noon, since at this point in time the day-ahead scheduling is optimized. However, with current electricity market structures in most of the European countries, the international electricity trade does not consider international load flow restrictions. In the following planning periods, rescheduling is done on an intraday base a) to balance forecast errors of the precedent planning periods and b) in order to achieve the required equilibrium between generation and load under consideration of the distribution of the physical load flow on individual cross-border interconnectors. With these recourse actions, the precedent day-ahead unit commitment and scheduling has to be considered. This resulting planning process is illustrated in Fig. 2. For each planning period an optimisation problem is solved. The applied scheduling process reiterates every three hours. Thus, the scheduling proceeds in detail as follows:

1. With every planning period starting at noon, day-ahead scheduling for the hours of the following day is optimised. In order to do so, a perfect forecast of load and wind up to 36 hours ahead has been considered in this application. The solution values of the variables for the day-ahead scheduling are fixed and are considered in the subsequent planning periods. In the following model description, these variables are labelled with the superscript "Day".

2. In subsequent planning periods, rescheduling of the electricity system operation is optimised taking load flow restrictions into account. Rescheduling is determined by recourse decisions as up- or down-regulation, for example of the power plant dispatch and international electricity exchange. They are labelled in the following with the superscripts "+" or "-", respectively. Thereby, the endogenous optimised values of the day-ahead variables are considered for the resulting scheduling. For example, the finally realised power dispatch of power plant i in the hour t is determined by $P_{i,t} = P_{i,t}^{Day} + P_{i,t}^{+} - P_{i,t}^{-}$.

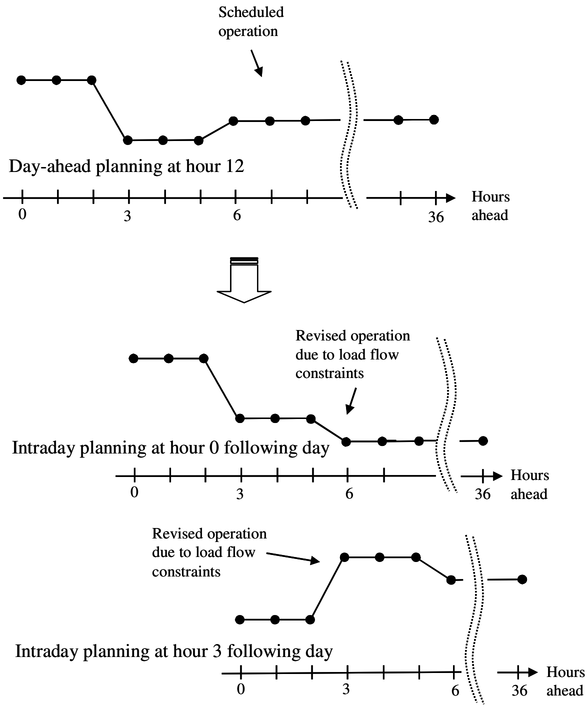

Fig. 2. Scheduling process with rolling planning.

Objective function

The objective function (1) minimizes the total expected operation costs in the system considered. With the objective function, mainly costs of power plant operation and start-ups are covered. The operation cost function $c_i^{Operation}(P_{i,t}^{Day} + P_{i,t}^{+} - P_{i,t}^{-})$ mainly considers fuel costs depending on varying power plant efficiencies between full and part load operation, costs for the use of CO_2 emissions certificates and further variable operation and maintenance costs. Individual start-up costs $c_i^{Start-up}$ are described as a function of the positive increase of the current online capacity $P_{i,t}^{Onl}$ between two time steps and the specific start-up fuel consumption as well as wear and tear. To compensate for applying a time limited optimisation period, correction terms c_i^{Corr} are added that consider opportunity costs of online units and the value of storage fill levels at the final time step of optimisation period. The opportunity costs of online units are determined according to the start-up costs of those units. The value of storage fill levels is set equal to the marginal value of the fill level of storages.

$$\min\left(\sum_{t\in T}\left(\sum_{i\in I} c_i^{Operation}\,(P_{i,t}^{Day\_ahead} + P_{i,t}^{+} - P_{i,t}^{-})\right.\right.$$
$$\left.\left. + c_i^{Start-up}\,(P_{i,t}^{Online}, P_{i,t-1}^{Online}) - \sum_{i\in I} c_{i,T}^{Correction}\right)\right) \qquad (1)$$
$$\forall i \in I;\, t \in T;\, r, \bar{r} \in R$$

Restrictions on electricity markets as well as on unit commitment and dispatch

One electricity balance is defined both for the day-ahead and for the intra-day electricity market. This differs from the common approach of electricity market models that consider solely one single kind of electricity market constraint. The electricity balance constraint for the day-ahead market determined at noon is defined in (2). The sum of conventional power generation and expected wind power production $cap_{r,t}^{Exp\_Wind}$ plus imported/exported power has to equal the sum of electricity demand and of power used for loading electricity storages such as pumped hydro storages. Optionally, physical load flow restrictions can be considered already during the day-ahead planning, see as well section IV. The corresponding variables are fixed after the day-ahead planning for subsequent planning periods. The marginal values obtained for (2) are subsequently interpreted as day-ahead electricity prices.

$$
\begin{aligned}
&\sum_{i \in I_r} P_{i,t}^{Day-ahead} + cap_{r,t}^{Exp\_Wind} + \sum_{r,\bar{r} \in R} P_{Sched,\ r,\bar{r},t}^{Trans,\ Day-ahead} \\
&= d_{r,t}^{Elec} + \sum_{i \in I_r^{Elecstorage}} W_{i,t}^{Day-ahead} \\
&\forall i \in I; t \in t^{Not\_Fixed}; r, \bar{r} \in R
\end{aligned}
\tag{2}
$$

The rescheduling of the unit commitment and dispatch in order to fulfil to physical load flow restrictions is described by the electricity balance constraint (3). The model variables $P_{r,\bar{r},t}^{Trans,+}$ and $P_{r,\bar{r},t}^{Trans,-}$ describe the necessary modification of the transmission scheduled day-ahead. It can be balanced by up and down regulation of power plants, by changes in the loading of storages as well as by wind power curtailment $P_{r,t}^{-,Wind}$. In the case that physical load flow restrictions are already considered day-ahead, there is no need to modify the unit commitment and dispatch as well as the loading of storages.

$$
\begin{aligned}
&\sum_{i \in I_r} (P_{i,t}^{+} - P_{i,t}^{-}) + \sum_{i \in I_r^{Elecstorage}} (W_{i,t}^{-} - W_{i,t}^{+}) - P_{r,t}^{-,Wind} \\
&= \sum_{r,\bar{r} \in R} (P_{r,\bar{r},t}^{Trans,+} - P_{r,\bar{r},t}^{Trans,-}) \\
&\forall i \in I; t \in T; r, \bar{r} \in R
\end{aligned}
\tag{3}
$$

Power reserves are subdivided into spinning and secondary reserves. Spinning reserves are further differentiated into incremental and decremental reserves. The provision of both kind of spinning reserves by power plants or storage devices is determined day-ahead at noon, whereas the provision of secondary reserves can be optimized as well during intraday planning periods.

Modelling adequately the maximum and minimum power output constraints as well as the consideration of start-up costs of individual power plants requires a mixed-integer formulation of the power plant scheduling problem, compare e.g. [9]-[11]. However, a mixed-integer model that considers a large power system with a high number of power plants and representation of repeated scheduling procedures becomes computationally intractable. In the present model individual power plants are therefore aggregated to unit groups subject to main fuel, technology and age. To describe start-up costs and similar restrictions, the running capacity of these unit groups at each time step – called capacity online - is described through a continuous variable, following the approach described in [12]. The capacity online $P_{i,t}^{Online}$ then obviously is bounded by zero from below and by the maximal generating capacity cap_i^{Max} from above. Taking into account the average unavailability of unit group *i* $cap_i^{Unavail}$, one gets:

$$P_{i,t}^{Online} \leq (1 - cap_i^{Unavail}) \cdot cap_i^{Max} \qquad (4)$$
$$\forall i \in I; t \in T$$

However, the value of $P_{i,t}^{Online}$ has to meet additionally the following conditions: $P_{i,t}^{Online}$ has to exceed the actual power production plus the contribution to spinning reserves:

$$P_{i,t}^{Day-ahead} + P_{i,t}^{+} - P_{i,t}^{-} + P_{i,t}^{Sp,+} \leq P_{i,t}^{Online} \qquad (5)$$
$$\forall i \in I; t \in T$$

Furthermore, the online capacity multiplied with the minimum output factor cap_i^{Min} forms a lower bound to the possible power output minus the provision of decremental spinning reserves:

$$P_{i,t}^{Day-ahead} + P_{i,t}^{+} - P_{i,t}^{-} - P_{i,t}^{Sp,-} \geq cap_i^{Min} \cdot P_{i,t}^{Online} \qquad (6)$$
$$\forall i \in I; t \in T$$

The variation of the online capacity is furthermore restricted by the consideration of start-up times. Accordingly, it is possible to change the unit commitment only after the start-up time of the unit group *i* has passed:

$$P_{i,t}^{Online} = P_{i,\tau}^{Online} \qquad (7)$$
$$\forall i \in I; \tau \text{ with } t \leq \tau < t + t_i^{Start-up\_time}$$

The consideration of start-up times implies that it is not possible to increase the online capacity of a unit group in the first hours of a planning loop. Hence, before optimizing a planning period, the online capacity of a unit group in the first hours of the planning period has to be fixed to the value of the online capacity determined in the previous planning period describing the same hours.

Besides these equations describing the operation of thermal power plants, further constraints for hydro seasonal storages and electricity storages like pumped hydro storages have to be considered. Both the maximal and minimal content of hydro reservoirs and electricity storages, the available pumping capacity and storages losses have to be adequately described. Furthermore, the contribution of seasonal hydro reservoirs and electricity storages to reserves has to be considered. The model is further enhanced through a detailed modeling of combined heat and power (CHP) plants.

Restrictions on electrical load flow

In order to account for the physical distribution of load flows between the European countries due to electricity trading activities, the international cross-border flow can be described by the use of a zonal Power Transfer Distribution Factors matrix (PTDF), see acknowledgements. With the application of zonal PTDF matrixes, principally the contribution of one commercially scheduled transaction $P_{Sched,r,\bar{r},t}$ between two zonal grid nodes, i.e. in this case between two European countries, on the physical loading $P_{r,\bar{r},t}$ of individual cross-border connections is determined:

$$P_{r,\bar{r},t} = [PTDF] \cdot P_{Sched,\, r,\bar{r},t} \qquad \forall r,\bar{r} \in R;\, t \in T \qquad (8)$$

PTDF matrixes are notably a valuable measure to explicitly consider endogenous load flows for the evaluation of network extensions and are superior to the common NTC approach. In the European Wind Integration Study, PTDF matrixes have been applied in order to assess the economical aspects of enhancements of cross-border interconnector capacities [13]. The individual factors of the PTDF matrix applied for this purpose and within this paper are determined based on a full UCTE-wide network model, with a reference load and generation situation.

The resulting cross-border load flows are limited by the assumed maximal transmission capacity $cap_{r,\bar{r}}^{Trans,Max}$ of the aggregated cross-border lines according to (9). In the case without day-ahead load-flow based market coupling, see section IV., NTC values are considered for day-ahead planning and TTC values for the subsequent rescheduling, [14] and acknowledgements. In the case with day-ahead load-flow based market coupling, TTC values are considered for both markets.

$$\begin{aligned} & P_{Sched,\, r,\bar{r},t}^{Trans,\, Day-ahead} + P_{r,\bar{r},t}^{Trans,\, +} - P_{r,\bar{r},t}^{Trans,\, -} \\ & \leq cap_{r,\bar{r}}^{Trans,\, Max} \qquad \forall r,\bar{r} \in R;\, t \in T \end{aligned} \qquad (9)$$

Application Case

For this analysis, the electricity markets of all countries of EU27 except Malta, Cyprus and the Baltic countries are considered. Additionally, Norway, Switzerland and the Balkan countries are described. Fig. 3 shows these countries marked in grey.

Fig. 3. Considered European countries marked in grey.

One country is represented by one zonal node in the European transmission network (beside Denmark that has been split into Denmark West and Denmark East). The model is coupled to a database, which has detailed information on the European power system. The sources of most important data are summarized in Table I.

For a detailed description of the data except for grid related data it is referred to [15]. Notably data on PTDF values and on available interconnector capacities was derived by the European transmission system operators within the framework of the European Wind Integration Study [13], see acknowledgements.

TABLE I
DATA AND APPLIED SOURCES

Data on	Source	Resolution
Fuel & CO_2 prices	IEA	Yearly
Load profiles	ENTSO-E	Hourly
Annual load	ENTSO-E	Yearly
Wind power generation	Tradewind project/	Hourly
RES-E deployment (excl. wind power)	Green-X	Yearly
Hydro inflow	Marketskraft / national statistics	Hourly / yearly
Reservoir levels	Marketskraft / national statistics	Seasonal
Conventional power plants	Platts database/ own research	Single plant
Technical parameters	Academic literature	Single plant

Heat load	National statistics	Hourly
Grid data / PTDF matrix	EWIS	Yearly

The model analyses focus the year 2015 with largely increased wind power capacities in order to demonstrate the value of market coupling in a setting with increased uncertainty of volatile generation. The assumed wind generation capacities and time-series are based on data of the Tradewind project [16], [17], see Fig. 4. Renewable capacities excluding wind are derived with help of the Green-X tool based on a database that combines promotion policies for renewables and potentials of renewables in Europe [18].

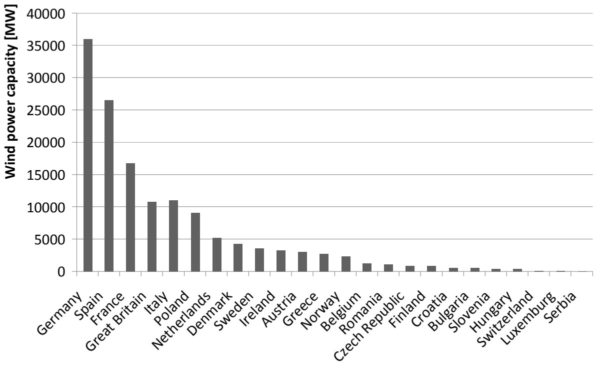

Fig. 4. Assumed wind power capacities in European countries [**16**].

Results

In order to evaluate the effects of load-flow based market coupling, two yearly hourly model runs in 2015 are performed: a) In order to model the international electricity trade as it is organized nowadays between most of the countries, is not sufficient to perform solely a market modeling with NTC based restrictions. Hence, the models differentiation of the day-ahead market and the intraday market to highlight the required redispatch is applied. In the day-ahead market, exchanges are only limited to maximal transfer capacities (notably NTC) values as they are envisaged by traders. But on the intraday market, the PTDF restrictions are taken into account. In case that the maximal transfer capacities based scheduled flows and the corresponding dispatch are not feasible in the PTDF setting, the model endogenously redispatches flows and power plant operation until it becomes feasible. Hereby the most cost efficient but still feasible solution is chosen by the model. This model run is labeled in the following "NTC-case". b) A perfect load-flow based coupling of all European electricity markets is described, which corresponds to an overall system optimization with PTDF restrictions on the power flows within both the day ahead and intraday market. This second model run is labeled in the following "MC-case". When comparing the model run of a) and b), one can estimate the overall impacts of load-flow based market coupling taking into account at day-ahead markets.

The total annual system operation costs of the considered European electricity system amounts to 105,079.6 Mio € in the NTC-case and to 104,970.5 Mio € in the MC-case with the considered basic conditions. Hence, an absolute reduction of 109.1 Mio € or relatively of 0.1 % of the total system operation costs can be obtained with load-flow based market coupling taking into account already day-ahead. Looking at selected single countries, the system operation costs decrease mainly in the countries Bulgaria, Romania, France and Luxembourg, see Table II. However, a couple of countries like Germany, the Netherlands, Czech Republic, Switzerland and Hungary show increased system operation costs.

TABLE II
TOTAL SYSTEM OPERATION COSTS IN SELECTED COUNTRIES

Country	**NTC [Mio €]**	**MC [Mio €]**	**Abs. diff. [Mio €]**	**Rel. diff. [%]**
Bulgaria	452.3	413.8	38.4	8.5
Romania	1,136.9	1,082.4	54.4	4.8
France	5,164.3	5,113.2	51.1	1.0
Luxembourg	118.7	117.6	1.1	1.0
Belgium	2,811.3	2786.5	24.7	0.9
Italy	16.214.7	16,193.7	20.9	0.1
Poland	6,140.5	6,135.6	4.8	0.1
Sweden	1,162.6	1,162.1	0.5	0.0
United Kingdom	13,994.7	13,994.5	0.2	0.0
Germany	23,963.6	23,977.7	-14.1	-0.1
Norway	501.4	501.8	-0.4	-0.1
Netherlands	6,726.4	6,744.4	-18.0	-0.3
Czech Republic	2,141.0	2,149.1	-8.1	-0.4
Switzerland	458.8	462.5	-3.7	-0.8
Hungary	692.5	706.4	-13.9	-2.0

The introduction of load-flow based market coupling further leads to modified day-ahead electricity prices. The average day-ahead electricity price for the whole of Europe decreases from 51.81 €/MWh to 49.52 €/MWh with day-ahead market coupling, which is equal to a reduction of 4.4 %. In particular, the annual average day-ahead electricity price is decreased in the countries Bulgaria, Switzerland, France, Poland, Sweden and United Kingdom, see Table III. Comparable to total system operation costs, as well an increase of the annual average day-ahead electricity price can be observed in several countries.

TABLE III

ANNUAL AVERAGE OF DAY-AHEAD ELECTRICITY PRICES IN SELECTED COUNTRIES

Country	**NTC** [€/MWh]	**MC** [€/MWh]	**Abs. diff.** [€/MWh]	**Rel. diff.** [%]
Bulgaria	48.33	39.81	8.52	17.6
Switzerland	55.01	48.32	6.69	12.2
France	36.18	32.63	3.55	9.8
Poland	67.31	66.26	1.05	1.6
Sweden	43.48	43.46	0.02	0.1
United Kingdom	66.28	66.27	0.01	0.0
Norway	55.78	55.84	-0.06	-0.1
Netherlands	55.02	55.49	-0.48	-0.9
Hungary	56.41	57.12	-0.71	-1.3
Czech Republic	56.35	57.78	-1.43	-2.5
Germany	54.99	56.55	-1.56	-2.8
Romania	55.94	57.65	-1.71	-3.1
Belgium	54.53	56.70	-2.16	-4.0
Italy	62.74	64.93	-2.19	-3.5
Luxembourg	55.08	58.27	-3.19	-5.8

The changed system operation costs and electricity prices reflect a modified use of conventional power plants and export/import schemes in individual European countries. For example in Belgium, similar to France, Poland, Hungary and Romania, the total annual electricity generation is reduced, see Table IV. This reduction is mainly based here on the decrease of the electricity generation based on coal and to a lower extent on natural gas fired power plants. The electricity generation from wind power plants is not affected. Overall, the average system operation costs per electricity generation decreases from 30.73 €/MWh in the NTC-case to 30.60 €/MWh in the MC-case. But for example in Germany and the Netherlands, the electricity generation increases by 0.05 % and 0.2 % with load-flow based market coupling, respectively. The average system operation costs per electricity generation increases as well from 43.64 €/MWh in the NTC-case to 43.65 €/MWh in the MC-case in Germany and from 54.72 €/MWh to 54.73 €/MWh in the case of the Netherlands. Correspondingly, the results cannot be generalized for all countries.

TABLE IV

ANNUAL ELECTRICITY PRODUCTION DEPENDING ON FUEL IN BELGIUM

Fuel	**NTC [TWh]**	**MC [TWh]**	**Abs. diff. [TWh]**	**Rel. diff. [%]**
Biomass	1.28	1.28	0.0	0.0
Coal	4.16	3.93	0.23	5.5
Misc	2.12	2.12	0.0	0.0
Natural Gas	43.03	42.86	0.18	0.4
Nuclear	36.74	36.74	0.0	0.0
Pumped Hydro	0.60	0.59	0.01	0.0
Further Hydro	0.43	0.43	0.0	0.0
Wind	3.12	3.12	0.0	0.0
Total	91.48	91.07	0.41	0.5

Furthermore, trading electricity under consideration of the physical load flow already day-ahead certainly leads to modified electricity exchanges between the European countries. This is in the following exemplarily analyzed for the annual exchange balance of Germany, the country with the largest wind power capacity installed and located in the centre of Europe. Please note again that these results cannot be generalized for other countries. In the NTC-case, the total annual exports amount to 59.4 TWh and the total annual imports to 88.4 TWh giving an export balance of -29.0 TWh. With load-flow based market coupling, the total annual exports are decreased to 29.6 TWh and the total annual imports to 58.2 TWh. Thus, the interchanges are generally reduced yet the export balance of -28.6 TWh remains approximately unchanged. The annual electricity interexchange balance to and from individual neighboring countries is depicted in Fig. 5. With load-flow based market coupling, an increased export to the countries Austria and Switzerland can be observed. Especially the net import from Austria is considerably reduced to a nearly balanced use of the interconnection. Whereas the annual balances on the further interconnectors show an increased import. The sign of the exchange balance on the interconnectors to Switzerland and Luxembourg is altered with the introduction of load-flow based market coupling. The annual use of the HVDC links to DK_E and Sweden is approximately the same in both directions for both cases.

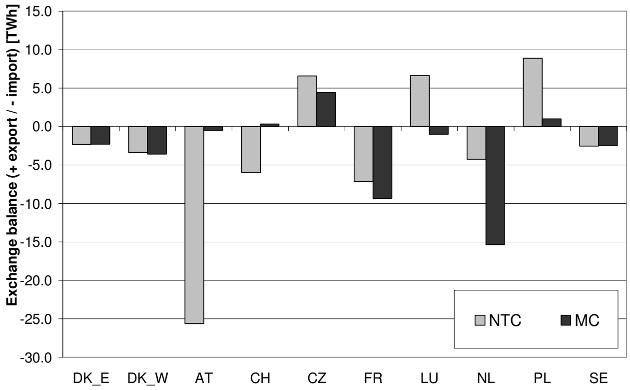

Fig. 5. Annual electricity exchange balances to and from Germany in the NTC- and MC-case.

In order to investigate the impact of wind power generation onto the benefits of market coupling we perform a sensitivity analysis on the installed wind power capacities. Herewith we increase the medium expansion scenario of [16] with 143,1 GW capacities towards the high expansion scenario with 184,35 GW of wind power installed in Europe. This corresponds to an increase of approximately 28%. Now turning to the resulting cost reductions induced by market coupling, the following savings can be described for selected European countries:

TABLE V
SENSITIVITY: TOTAL SYSTEM OPERATION COSTS IN SELECTED COUNTRIES

Country	**NTC** [Mio €]	**MC** [Mio €]	**Abs. diff.** [Mio €]	**Rel. diff.** [%]
Bulgaria	445.8	409.6	36.2	0.08
Romania	1118.9	1057.8	61.1	0.05
France	4926.6	4876.7	49.9	0.01
Luxembourg	95.1	93.9	1.2	0.01
Belgium	2395.1	2346.1	49.0	0.02
Italy	15470.7	15436.0	34.7	0.00
Poland	5230.2	5164.7	65.5	0.01
Sweden	1116.8	1116.7	0.1	0.00
United Kingdom	12651.5	12655.7	-4.2	0.00
Germany	25021.0	25132.4	-111.4	0.00
Norway	479.3	479.1	0.2	0.00
Netherlands	6416.4	6438.6	-22.1	0.00
Czech Republic	2449.4	2467.7	-18.4	-0.01
Switzerland	481.2	479.5	1.7	0.00

Hungary	880.8	909.0	-28.2	-0.03

The overall savings amount to 68, 77 Mio €/a for the whole of Europe which corresponds to only 0, 1% of the total operational system cost. It can be seen, that in this setting the overall benefits of market coupling are decreased compared to the medium wind capacity scenario investigated above. The reason for this development is the fact that additional wind generation is on average reducing the price differences between the countries which reduces scheduled exchanges. When scheduled exchanges are reduced it becomes less likely that physical constraints are violated and hence there is less need for costly redispatch. Due to this the overall benefits of market coupling which avoid redispatching, become decreased. Hence, more wind power has elevated the problem of redispatch due to technical constraints. Looking onto the yearly average price differences between the NTC and the MC calculation of the sensitivity case confirms this observation:

TABLE VI
SENSITIVITY: ANNUAL AVERAGE OF DAY-AHEAD ELECTRICITY PRICES IN SELECTED COUNTRIES

Country	**NTC [€/MWh]**	**MC [€/MWh]**	**Abs. diff. [€/MWh]**	**Rel. diff. [%]**
Bulgaria	47.90	39.73	8.18	0.17
Switzerland	56.47	49.93	6.55	0.12
France	33.82	30.77	3.05	0.09
Poland	67.38	64.28	3.10	0.05
Sweden	40.81	40.87	-0.06	0.00
United Kingdom	64.74	64.72	0.02	0.00
Norway	52.67	52.70	-0.03	0.00
Netherlands	55.84	54.87	0.97	0.02
Hungary	57.61	67.30	-9.70	-0.17
Czech Republic	57.03	59.35	-2.32	-0.04
Germany	56.05	57.35	-1.30	-0.02
Romania	55.88	58.17	-2.29	-0.04
Belgium	55.08	54.02	1.06	0.02
Italy	62.48	64.07	-1.59	-0.03
Luxembourg	56.06	54.68	1.38	0.02

Here we can observe that average price difference in Europe is reduced to only 1,5% between the market coupling and the NTC redispatch case. On average day ahead power prices are reduced by 0,77€/MWh. This sensitivity analysis has shown that wind power is not necessarily an argument for market coupling, because wind might be decreasing the amount of scheduled flows which might cause problems on physical constraints.

Conclusion

Increasing international electricity trade between European countries and growing intermittent wind power generation leads to an extended usage of available interconnectors between countries. With load-flow based market coupling, an improved usage of cross-border interconnector capacities as well a reduction of power plant redispatch costs in order to adapt dispatch and scheduled flows to physical limits are expected.

Based on an electricity market optimisation model taking into account the chronological sequence of several electricity markets, the impacts of European-wide load-flow based coupling of day-ahead markets on system operation costs, electricity prices at day-ahead markets and power system operation have been assessed for a projection of the year 2015 with large-scale wind power. The model's innovative capability to differentiate between individual electricity markets and to take simultaneously into account endogenous load-flows by the consideration of PTDFs, as provided by the European Wind Integration Study, allows deriving adequate results on the effects of large-scale wind power integration and modified electricity market schemes.

With day-ahead load-flow based market coupling, a reduction of the total system operation costs of the entire European electricity system of 0.1 % and of the average annual day-ahead electricity price of 4.4 % can be observed. In some countries, the decrease of system operation costs and day-ahead electricity prices is more pronounced. The development of annual system operation costs in individual countries is mainly dependant on an increased or decreased annual total electricity generation with correspondingly modified exchange balances and on a varying use of individual power plant technologies and fuels. In particular with the latter, resulting day-ahead electricity prices are affected as well. There are no significant impacts on the operation of wind generation which continues to be dispatched in preference to other more expensive generation. However, the obtained results are dependant on the assumed development of basic conditions like for example future load growth, wind power capacities as well as fuel and CO_2 emission certificate prices. Moreover, the consideration of constant cross-border transmission limits and PTDF values throughout a year has certainly impacts on obtained results.

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