RE-Shaping: Shaping an effective and efficient European renewable energy market

D20 Report:

Consistency with other EU policies, System and Market integration

- A Smart Power Market at the Centre of a Smart Grid -

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Supported by INTELLIGENT ENERGY EUROPE

Grant agreement no. EIE/08/517/SI2.529243

Karlsruhe, October 19, 2011

www.reshaping-res-policy.eu

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The RE-Shaping project

Year of implementation:	July 2009 – December 2011
Client:	European Commission, EACI; Intelligent Energy – Europe - Programme, Contract No. EIE/08/517/SI2.529243
Web:	www.reshaping-res-policy.eu

Project consortium:

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The core objective of the RE-Shaping project is to assist Member State governments in preparing for the implementation of Directive 2009/28/EC and to guide a European policy for RES in the mid- to long term. The past and present success of policies for renewable energies will be evaluated and recommendations derived to improve future RES support schemes.

The core content of this collaborative research activity comprises:

- Developing a comprehensive policy background for RES support instruments.
- Providing the European Commission and Member States with scientifically based and statistically robust indicators to measure the success of currently implemented RES policies.
- Proposing innovative financing schemes for lower costs and better capital availability in RES financing.
- Initiation of National Policy Processes which attempt to stimulate debate and offer key stakeholders a meeting place to set and implement RES targets as well as options to improve the national policies fostering RES market penetration.
- Assessing options to coordinate or even gradually harmonize national RES policy approaches.

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This report

is conducted within the European research project:

RE-Shaping

Shaping an effective and efficient
European renewable energy market

Acknowledgement:

The authors and the whole project consortium gratefully acknowledge the financial and intellectual support of this work provided by the Intelligent Energy for Europe – Programme.

Supported by
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Executive Agency for Competitiveness and Innovation

Intelligent Energy for Europe

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1 Executive Summary

Background and Scope

In the EU, at least 200 gigawatts (GWs) of new and additional renewable electricity sources may be needed by 2020. The aim of this report is to analyse whether the current electricity market and system design is consistent with such an ambitious target.

Using an international comparison, we identify opportunities to improve the power market design currently in place across EU countries so as to support the large scale integration of renewable energy sources. Thereby the we derived the following summary conclusions:

- The current structure does not make effective use of network transmission capacity, thus increasing costs for transmission expansion. More effective use of existing transmission capacity can support renewable integration– in this report, see **Section 2 (page 13)**;
- It does not allow for the full optimise European system dispatch in response to improved wind forecasts, and thus forgoes cost and emission savings opportunities – see **Section 3 (page 33)**;
- In addition, it does not create transparent signals about system constraints to inform transmission network investment decisions.

Comparing the different design options, points to a set of advantages of the market utilising a nodal or locational marginal pricing (LMP). See **Section 4 (page 67)** for quantitative findings and implications.

A. Congestion Management in European Power Networks

Congestion represents the situation when technical constraints (e.g., line current, thermal stability, voltage stability, etc.) or economic restrictions (e.g., priority feed-in, contract enforcement, etc.) are binding and thus restrict the power transmission between regions; congestion management aims at obtaining a cost optimal power dispatch while accounting for those constraints.Several market designs have been explored in the past to achieve some integration of congestion management and balancing markets. In contrast to the EU, some areas of the US have adopted an approach based on locational marginal pricing (or nodal pricing – a description of which can be found in **Section 4**).

Table 1-1 illustrates how the efficiency of the system can be enhanced by integrating congestion management and balancing markets on a European scale. The congestion

management requirements listed above can be addressed by integrating these markets. Several market design options have been explored in the past to achieve some of this integration, but as the table outlines, only nodal pricing demonstrated the capacity to achieve full integration.

Table 1-1: Aspects of congestion management and balancing markets that benefit from European integration, and market design options to achieve this integration

	(i) Integration with domestic congestion management	(ii) Joint allocation of international transmission rights	(iii) Integration with day ahead energy market	(iv) Integration with intraday/ balancing market	(v) Transparency of congestion management
Bilateral transmission rights auction	No	No	No	No	No
Joint multi-country auction of NTC rights	No	Yes	No	No	No
Multi-region day-ahead market coupling (zonal pricing)	No (only at zonal level)	Possible	Yes	Intraday	No
Nodal pricing	Yes	Yes	Yes	Possible	Yes

B. Balancing and Intraday Market Design

Historically, balancing markets have been the only markets to provide reserve and response operations needed to respond to unplanned power plant outages or load prediction errors. Transmission System Operators (TSOs) contract in day-ahead and longer-term markets with generators to provide flexibility that can be called upon on short notice to balance the system.

Balancing services were provided nationally, or in the case of Germany, within the region of the TSO. Mutual support between operating regions was restricted to emergency situations, such as unexpected power plant failures, and not remunerated (only energy that was provided had to be returned).

In recent years, renewable energy and newly installed wind power have prompted additional demand for adjustments during the day. This demand arose predominantly due to the uncertainty of day-ahead forecasts for renewable feed-ins. This trend will continue as EU member states increase the deployment of wind power and other intermit-

tent renewable energy sources to deliver the 20% renewable target formulated in the European Renewables Directive of 2009.

To meet this new requirement, intraday and balancing markets need to be adjusted to allow the TSOs to appropriately respond to increased uncertainty.

Comparing different EU power market designs and other options points to the benefits of a nodal pricing approach, providing appropriate price signals for the economic design and evaluation of power grids, encouraging the effective use of transmission capacity and improving interfaces between onshore and offshore networks.

Table 1-2: The following table summarises how different market design options allow for intraday optimisation of the power system in the presence of wind power, and how they perform against criteria used for their evaluation

	Dispatch adjusted during day	Balancing requirements / provision adjusted during day	Flexible use of individual conventional power stations	International integration of intraday / balancing markets	Integration of demand side response services	Effective monitoring of market power possible
UK system				N/A		
German system		N/A				
Nordpool						
Spanish system				N/A		
Nodal pricing system						

C. Quantification of Nodal Pricing

We compared two market designs across Europe to explore how renewable integration is impacted: (i) an optimized and traditional approach of implicit auctions of transmission capacity between nationally defined price zones; and (ii) a nodal pricing approach.

While other research papers[1] have discussed the various merits of nodal over zonal pricing regimes, the purpose of our paper was to quantify the benefits in terms of cost savings and increased transmission utilisation in the EU (ENTSO-E operating region). To that end, teams in Madrid and Dresden[2] modelled the power grid operating under traditional pricing zones with varying levels of wind penetration, and compared various system metrics (including power transfers and prices) with those from a nodal price approach.

Qualitative and Quantitative Results

The simulations using the Dresden and Madrid methods confirmed qualitative results from previous studies.

- Zonal-national boundary variations. The calculations show that under a nodal pricing structure, **price zones do not match country borders and change depending on the amount of wind output**. The implication is that zonal pricing methodologies do not capture the physical reality of the grid. As a result, there is an incentive for TSOs to limit international flows to avoid domestic congestion. Maintenance of artificial zonal prices creates considerable redispatch costs and gaming opportunities.
- Congestion dynamics under varying wind scenarios. The variation in distribution of congestion under different wind scenarios suggests that **pricing zones have to be very small if congestion within zones is to be limited**, illustrating the need for nodal pricing.

The nodal pricing simulations illustrated that congestion – and price – patterns vary considerably between wind scenarios. This suggests that approaches that aim to define price zones within countries are not suitable to address internal congestion, as the zones would either have to vary (impractical for contracting purposes), or be small (equal to nodal pricing).

Furthermore, the quantitative differences in the model between a nodal pricing regime and the current EU system were as follows:

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1 Schweppe et al. (1988) and Hogan (1992 - Contract Networks for Electric Power Transmission, J. Reg. Econ 4 (3).

2 Madrid Universidad Pontificia Comillas and Dresden University of Technology.

- *International transfers*. The nodal pricing approach leads to an **increase of up to 34% in international MW transfers between countries compared to the flow patterns simulated for implicit auctions applied between all European countries**. This imporves the ability of the network to accommodate large volumes of intermittent energy sources.
- *Cost savings.* Annual **savings of system variable (mainly fuel) costs under a nodal pricing structure are in the order of €0.8 - €2.0 billion relative to a zonal pricing approach with implicit auctions**. This represents an average of 1.1% - 3.6% of operational costs[3]. These results are in line with empirical values from the USA and the results of a simulation model for a small-scale network.
- *Country level marginal prices*. **Weighted marginal prices are lower under a nodal pricing regime in 60% to 75% of EU countries**. Real-time congestion mitigation measures such as wind spilling, load shedding and power plant re-dispatching are relatively costly options, the uses of which are minimized under a nodal approach.

3 These do not include possible savings in unit commitment costs such as start-up and minimum run costs.

2 Congestion Management in European Power Networks: Criteria to Assess the Available Options

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2.1 Introduction

Since liberalization in the 1990s, the trading of bulk power in long-term and day-ahead markets has become one of the key mechanisms for enhancing the competitiveness of national power markets. Efficient use and allocation of transmission capacity – i.e., congestion management – is critical to maximizing these benefits of power trade.

To achieve 20% of all energy requirements from renewable sources by 2020, EU member states will be pursuing large scale investment in renewable generation. Increasing variability in the energy portfolio will establish new flow patterns, change the current national and cross-border congestion profiles and will introduce three weaknesses in the current European systems for congestion management (Brunekreeft et al., 2005):

1. *Inefficiencies within countries*. Within countries, the market does not communicate complete information on the value of generation at different locations, resulting in gaming opportunities and inefficient dispatch.

2. *Inefficiencies between countries*. Scheduling of transmission across country boundaries is treated separately from domestic dispatch, which leads to incomplete information flows on the state of the network and the expected development of demand and generation. The result is underutilization of the network and an increased risk from unexpected power flows.

3. *Inefficiencies in dynamic management*. Internationally available transmission capacity and its allocation are typically determined long before real time. This limits the ability of the European power system to flexibly deliver power and ancillary services across Europe in response to new information about demand and output, particularly from intermittent energy sources.

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4 Rodney Boyd (CPI Berlin), Thilo Grau (DIW/CPI Berin), and Harry van der Weijde provided research assistance. Funding was provided by UK Flexnet, Fingrid, and Climate Policy Initiative.

This paper will discuss these three weaknesses followed by an exploration of how they could be addressed on a European scale. We argue that locational marginal pricing (also known as nodal pricing) is the best candidate for a market design that can successfully address all of them, without creating additional problems[5].

Locational marginal pricing has been applied successfully in six regions of the US (O'Neill et al., 2006, 2008). The design of a locational marginal pricing scheme allows for several options, especially with respect to the treatment of intraday balancing, allocation of start-up costs, and automatic market power monitoring procedures (see the complementary paper by Borggrefe & Neuhoff, 2010).

The implementation of this pricing system in Europe, however, is far from straightforward. The US experience suggests that it is difficult to converge on one common approach using a bottom-up process, while opposition to market liberalization in general has impeded attempts of the Federal Energy Regulatory Commission (FERC) to harmonize and integrate these designs. As a result, its proposed Standard Market Design was not implemented in all US markets, and trade inefficiencies between adjacent markets could not be eliminated[6]. This experience points to the importance of clear guidance by European institutions to avoid a similar experience in Europe.

Initial observations in Europe suggest that we risk a repetition of this experience. The bottom-up initiatives of neighbouring countries do not seem to develop the scale of ambition for integration necessary to address these issues. Different initiatives have been proposed in the Spanish peninsula, the Benelux countries, the Nordic countries, and the South East European countries, risking a lock-in to inefficient market design and institutional solutions.

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5 Other discussions, as well as quantitative analyses of the benefits of locational marginal pricing in a European context are available in Buglione et al. (2009); De Jong et al. (2007); Ehrenmann and Smeers (2005); ETSO (2007); Green (2007); Leuthold et al. (2005); Strbac et al. (2007).

6 Indeed, locational marginal pricing may have even exacerbated barriers between regions, as the PJM and California markets have taken steps to limit the set of nodes at which neighbouring systems can schedule exchanges (Harvey, 2008). This is because under US National Electric Reliability Council (NERC) rules, deviations in such schedules involve no financial penalties; imbalances need only be made up by physical quantities at some time at any interface between adjacent control areas. This has resulted in games in which an exporting system actually delivers power to an importer's low price import node rather than the higher priced node where originally scheduled (and paid for). To protect against such games, system operators require that deliveries be scheduled at the lowest priced node, which, in general, makes trade less attractive.

Several institutions, such as the Agency for the Cooperation of Energy Regulators (ACER) and the EU Commission, could be envisaged to take a lead in formulating requirements for a harmonized European market design or even in outlining a process and setting up institutions for implementation. A political process can only succeed with high-level support that can overcome opposition from individual industry stakeholders. This could for example be achieved with the provision of free allocation of financial transmission rights to shield existing assets or domestic consumers from the impact of changing prices, while maintaining the efficiency improvement from the marginal incentive created by locational marginal pricing.

As the improvement of power market design can significantly enhance the competitiveness of the European power market, it will in turn reduce the rents large utilities can potentially capture in wholesale and balancing markets. This remains one reason why such attempts in the EU have been opposed and delayed over the last decade. In the US, opposition was largely addressed by providing free allocations of transmission rights to provide compensation.

This paper is structured as follows. In Section 2.2, we explain the three weaknesses of the current European power market in more detail, and identify five criteria that an effective congestion management scheme for the EU will need to satisfy. In Section 2.3, we explore options for jointly addressing the challenges of domestic and international congestion management, evaluating various designs against the criteria introduced in the previous section. In Section 2.4, we discuss options for mitigating risks involved with new power market designs, and in Section 2.5 we offer transition options in the context of the political economy of such changes to the market design.

2.2 Current Challenges in Congestion Management

2.2.1 Allocation of Domestic Transmission Capacity: Challenges of Current Redispatch Systems

Currently, in most countries bilateral energy trading can be pursued as if there would be no internal transmission constraints. Generators, traders, and demand submit their preferred power transactions by gate closure to the TSO.

Because internal constraints are disregarded, the system operator subsequently has to redispatch the power system. For instance, if congestion occurs north to south, the system operator will pay a generator in the north to reduce production or shut down and a generator in the south to start up or increase production. As examples of such redispatch systems:

- In the UK, the system operator has incentives to redispatch at least cost, which is possible on an island power system, but this structure is currently under review.
- In Spain, there is an automated procedure that uses market bids to redispatch the system.
- In the Netherlands, the operator has been considering a number of redispatch mechanisms (Hakvoort et al., 2009) but has ruled out locational marginal pricing.
- The results of these dispatch mechanisms include:
- Inefficiencies in redispatch, because not all actors participate in the redispatch procedure.
- Gaming of redispatch (also known as increase-decrease or inc-dec game): generators have an incentive to first schedule a flow, such that they will then receive payment not to generate at the export constrained location[7].
- Thus, generators in export- constrained regions obtain high revenues, which provide wrong incentives for the location of new plants[8].
- Generators in import constraint zones, that operators want to produce, have limited incentive to sell in the general energy market, but rather wait till the TSO has to contract directly with them to provide additional generation capacity.
- Demand also receives inappropriate incentives, as prices do not signal that power provision is more expensive in import-constrained areas than elsewhere.

There are two options to address these issues:

1. The Nordic countries have introduced small zones within countries in an essentially radial system. This is a reasonable solution when most or all congestion is between zones. However, defining such zones would be difficult in continental Europe, because of complex network topology. In the US, zonal markets were tried first in sev-

7 For instance, this so-called “inc-dec game” results in large payments to Scottish producers in the UK. As another example, the Miguel constraint in the California ISO system, which was internal to the southern California zone, enabled Mexican generators to earn $3-$4M/month from the inc-dec game prior to 2005. These problems destroyed the original PJM zonal system (Hogan, 1999) and plagued other zonal markets, which has lead all ISO-based markets in the US to adopt locational marginal pricing.

8 These investment problems were experienced in New England in 1998 and in the UK in the late 1990s. The response was implementation of a complex set of siting rules (Hogan, 1999). These problems have also been described in the case of the proposed Netherlands congestion management system (Hakvoort et al., 2009) by Hers et al. (2009) and Dijk and Willems (2009).

eral systems, but intra-zonal congestion turned out to be very large and impossible to eliminate, so all ISO-based systems have turned to locational marginal pricing[9].

2. A nodal system with full locational marginal pricing, in which the market operator attempts to include most or all transmission constraints in the transmission pricing model, addresses redispatch inefficiencies. In the US, this is now implemented in all six of the ISO markets (SPP, ERCOT, CAISO, ISO-NE, NYISO, and PJM).

2.2.2 Allocation of International Transmission Capacity

The traditional approach for allocating transmission capability between countries in the EU is to first define Net Transfer Capabilities (NTC) for bilateral transactions, and then to auction off this available capacity. This approach created initial clarity and a market-based mechanism for allocation and capture of transmission rents for re-investment. However, several shortcomings are now apparent.

NTC values are usually defined bilaterally, with occasional limits being defined for flows between one country and two or more of its neighbours. However, constraints affect several countries simultaneously, e.g., increasing export volume from Germany to France reduces capacity available for exports from Germany to Netherlands. NTCs generally do not consider this interaction, or if they do, they are defined conservatively so that feasibility is maintained under various different patterns of generation and demand.

A joint auction of international transmission capacity based on bids to buy and sell at different locations in the network has the potential to reflect this additional information. A simultaneous auction of total transmission capacity among EU countries, accounting for parallel flows, has been previously proposed (Audouin et al., 2002).

Such an auction handles international transactions as if international transmission lines are the only reason for constraints. However, transmission constraints also exist within countries, and it is not possible to fully differentiate between internal and international transmission constraints. Due to parallel flows, the same line constraints within Germany and the Benelux countries can limit both the available flow capacity from North-

9 In California, for instance, three major zones as well as some much smaller zones were defined for the market until superceded by a nodal system in 2009: northern California (NP16), middle California (ZP26), and southern California (SP26). The market monitor reports for the California ISO report that interzonal congestion costs were much less than intrazonal costs. For example, the intra-/interzonal costs were $426M/ $55.8M (2004), $151M/$26.1M (2005), and $207M/$56M (2006).

ern Germany to Southern Germany as well as the available capacity for exports from Germany to the Netherlands. This has two implications.

First, TSOs have an incentive to limit the transmission capacity they declare available for international transfers, so as to avoid congestion within their country. After all, few stakeholders complain about international limits, while costs incurred to resolve domestic congestion or to compensate wind generators not dispatched are subject to public scrutiny.

Second, the dominant location of generation within a country has a large influence on the international available transmission capacity. At times of strong wind output, for example, generation in Germany shifts towards the north and power is transmitted to the south not only through Germany but also through the Netherlands, Belgium, and France in the west. This reduces the capacity to transmit additional energy from Germany to the Netherlands and increases the capacity to export energy from Germany to France. But if internationally available transmission capacity is defined and allocated prior to the revelation of the exact wind and load domestic patterns, TSOs can only make conservative assumptions, limiting exports from Germany to the Netherlands and to France, assuming a low-wind scenario.

2.2.3 Timing of Transmission Allocation

Traditional transmission rights, e.g. those acquired in an auction, are obtained year, month, or day ahead. They can then be used to trade in energy markets. It is difficult for market participants to jointly re-trade transmission rights and interact in two national energy markets because of inconsistent closure times and transaction costs. This creates inefficient allocation and reduces the responsiveness of international flows to national bids, thus reducing the level of competition.

A first step toward improving this situation is market coupling as implemented between France, Belgium, and the Netherlands, and also between the Nordic countries. In the day-ahead markets, the national power exchanges receive bids for energy demand and supply and determine the market clearing price. The national power exchanges use an automated algorithm that allocates international transmission capacity to arbitrage national power markets, while making best use of the available transmission capacity, as defined in bilateral or multilateral NTC tables. There is considerable evidence of effi-

ciency gains from the French-Belgian-Dutch integration[10]. In the US case, Mansur and White (2009) report gains of trade amounting to about $170M/year from PJM's integration with certain Midwestern markets using a locational marginal pricing system, although in a different study, Blumsack (2007) expresses somewhat less confidence in the benefits of regional integration so he does not provide original analysis (see also Eto, 2005).

Current congestion management schemes usually fix the level of international transmission at the day-ahead stage, reflecting the historic generation pattern and the ability to anticipate demand at this stage. With increasing shares of wind generation and continued uncertainty about their output at the day-ahead stage, this market design is no longer suitable. It creates the need for nations to start fossil fuel plants and operate them on part load so that they can respond to the emerging wind situation, rather than using other resources on the power network to balance the system intraday across Europe.

Thus, an important goal of market integration should be to expand international markets to real-time, recognizing all network constraints. An effective congestion management scheme has to be fully integrated with the intra-day and balancing market design. Locational marginal pricing offers a clearly defined process that can achieve this objective.

Based on this discussion we can formulate five criteria that an effective congestion management system needs to satisfy:

1. Effective domestic congestion management and integration with international congestion management so as to make full use of existing transmission capacity.
2. Joint allocation of international transmission capacity, for the flexible use of transmission capacity where it is most needed at day-ahead stage.
3. Integration of transmission allocation with day-ahead energy market to transmission is used to make full use of low-cost generation options.
4. Integration of congestion management with intraday and balancing markets, so as to use the full flexibility across the power system to respond to improving wind forecasts and other uncertainties within the day.
5. A transparent approach to congestion management allows for effective cooperation and is the basis for robust analysis of future congestion patterns for public and private decision makers to guide investment choices.

We will now use these criteria to discuss options for effective congestion management.

10 The market operator has reported benefits (APX 2007), including lowered risk and easier access for the smaller players, increased use of existing interconnection capacity, and price convergence in the different markets.

2.3 Integrating European Congestion Management and Balancing Markets

The topology of the European power network does not follow national boundaries; significant congestion occurs both between and within countries. Table 1 illustrates how the efficiency of the system can be enhanced by integrating congestion management and balancing markets on a European scale.

Table 2-1: Aspects of congestion management and balancing markets that benefit from European integration, and market design options to achieve this integration

	(i) Integration with domestic congestion management	(ii) Joint allocation of international transmission rights	(iii) Integration with day ahead energy market	(iv) Integration with intraday/ balancing market	(v) Transparency of congestion management
Bilateral transmission rights auction	No	No	No	No	No
Joint multi-country auction of NTC rights	No	Yes	No	No	No
Multi-region day-ahead market coupling (zonal pricing)	No (only at zonal level)	Possible	Yes	No	No
Nodal pricing	Yes	Yes	Yes	Possible	Yes

Several market design options have been explored in the past to achieve some of this integration, but as the table outlines, only locational marginal pricing has the potential to achieve the full integration.

2.3.1 Zonal Pricing

Zonal pricing is implemented in the Nordic countries and in the Central Western European region between Belgium, France, Germany, Netherlands and Luxemburg; where the transmission network is split into zones. In the Central Western European region, price zones correspond to countries, whilst in the Nordic region, countries are subdivided into several zones.

Despite the significantly simpler network topology in the Nordic countries, however, it still remains difficult to define zones in a manner that avoids congestion within a zone. Furthermore, despite the presence of governance structures in Scandinavia that are

usually considered to be exemplary, stakeholder interests have prevented creation of sub-zones in Sweden, resulting in further inefficiencies (Bjorndal and Jörnsten. 2007).

The experience of the meshed network of the northeast US (PJM) shows that the identification of clearly constrained lines is difficult because they are constantly changing (Hogan, 2000). Hence, in the US, attempts to base transmission rights on flow-gate rights were abandoned. While this concept is not identical to zonal pricing, it must meet similar requirements for network topology. This example thus illustrates the difficulty and inefficiency of defining zones for zonal pricing in highly utilized meshed networks.

Further, although US markets that have had zonal pricing also had provisions to create new subzones, this has proven to be very difficult in practice. For instance, despite heavy congestion at the Miguel constraint, which resulted in significant consumer losses due to the inc-dec game, attempts to carve out a separate sub-zone for the export-constrained area in question failed.

This experience argues against the use of zonal pricing to integrate European power markets, except possibly in the very exceptional cases where a network is radial and congestion predictably occurs at a few bottlenecks.

2.3.2 Locational Marginal Pricing (Nodal Pricing)

Locational marginal pricing offers a mechanism that can integrate national and international congestion management. As its pricing builds on the physical reality of the network, it allows for a more efficient use of the network, reduces the opportunity to game the redispatch, and is, in principle, politically easier to agree upon because it captures physical reality rather than an arbitrary definition of zones.

As outlined in the seminal work of Schweppe et al. (1988), the basic idea of locational marginal pricing is to solicit bids to buy and sell power at buses in the network. Then, a ‘smart auction’ (an optimization model) is used to determine which bids and schedules to accept in order to maximize the value provided by the power system (the value of demand bids minus costs, as bid, of power supply) when subject to as many of the network constraints as can be captured in the optimization model. The shadow prices for the bus energy balances in the model express the marginal cost, i.e. the value of power supply/consumption at each location, if supply or load is changed by 1 MW. These prices capture the opportunity cost of transmission capacity, whether there are constraints (i.e., how dispatch has to be altered in order to accommodate more or less power flow at a location), and the cost of losses, if represented in the model. Market participants can also submit firm transmission schedules. They are imposed as binding constraints during the optimization, and have to pay (or receive) the price difference

between the node of power injection and withdrawal. This price risk can be hedged with financial transmission contracts.

In reality, not all transmission constraints can be represented due to their mathematical form, or because their transient nature may mean that they are not recognized by operators until it is too late to include them in the model. In such cases, the operator has to adjust the computed outcome with out-of-market (OOM) operator actions. As OOM operator actions can affect market prices, they are an on-going area of contention among stakeholders, as generators often suspect that they are being deprived of their rightful revenues if prices are distorted.

The prices from the 'smart auctions' in a locational marginal pricing system provide guidance to generation and transmission investors. In practice, merchant transmission that earns revenue based on spot prices (or awards of associated financial transmission rights) is very much the exception; nearly all transmission is built based on regulated processes that pay a pre-set rate of return. However, locational marginal prices provide guidance and objective information about where transmission investments may be most valuable.

Elements of Locational Marginal Pricing Systems

Since the publication of Schweppe's book in 1988, locational marginal pricing has come to mean more than just using bus energy balance prices to settle energy market transactions. Other elements (embodied in the FERC Standard Market Design, now called the Wholesale Market Platform) include (O'Neill et al., 2006, 2008):

1. Multi-settlement markets involving at least two sequential markets (day-ahead and real-time). Some markets have additional market clearing/settlement times to accommodate, for instance, the timing of import commitments (as in the California ISO Hour-Ahead Scheduling Process, HASP).
2. Day-ahead markets include payments for minimum run and start-up costs if not recovered by energy prices.
3. Local market power mitigation, where bids by generators in import-constrained areas may be mitigated to marginal cost (plus or minus) if they are anticipated to be able to significantly affect prices or other market outcomes.
4. Financial transmission rights, which are pure financial hedges that are backed by the system operator's congestion revenues -- the difference between nodal payments by load and nodal payments to generation (Hogan, 1992). These replace physical transmission rights.

5. In most cases, capacity or 'resource adequacy' markets, in which capacity (and in some cases demand response) is placed under contract and is obliged to bid into the market.
6. In most cases, a 'residual unit commitment' procedure that is run after the day-ahead market to ensure that there is sufficient capacity available to meet the forecast physical load, in case insufficient capacity clears the day-ahead market.

Although the ISO markets in the US share these characteristics, they differ in many details. For instance, the California market operates the day-ahead market and calculates prices using an iterative mixed integer optimization model in which linearizations of nonlinear AC transmission constraints are generated in each iteration and then a mixed integer linear program commits and dispatches the system. The PJM market instead uses a mixed integer linear-program provided by another vendor. Use of such optimization models rather than Lagrangian relaxation is now the norm in these markets.

Benefits of Locational Marginal Pricing

The benefits of improved scheduling of generation and interconnection flows in the short run will be measured by: the fuel savings from running more efficient plants that include wind power rather than less efficient plants that do not; reduced transmission losses from taking account of the spatial distribution of generation and reflecting marginal losses and spilling wind output; avoidance of the extra costs of ramping up and down plants at short notice in response to unanticipated loop flows; and reduced need to hold plants warm for rapid response.

If we assume that some 200-300 GW of generating capacity is connected, that 2% of cheaper power can replace more expensive power, and that the cost saving is €10/MWh, the saving on energy costs could be €50,000/hour or €300 million per year (assuming 6,000 hours for which this is possible). Marginal transmission losses could be of the same order, as could start-up costs. By reducing incentives for gaming, the system might avoid additional losses, but more importantly it would reduce the temptation for ad-hoc political and regulatory interventions that might have adverse effects on investor confidence and consumer support for markets.

In the longer run, better plant technology choice and location should create further benefits, while widening the effective market area creates more competition with well-known beneficial impacts on efficiency. Indeed, Green (2007) argues that market power amplifies the inefficiencies arising from ignoring spatial transmission cost and constraint differences, and so the gains from locational marginal pricing in an imperfectly competitive regime are likely to be even higher.

Suitability of Locational Marginal Pricing for EU Power System

In addition to weighing the relative advantages and disadvantages of the locational marginal pricing system, decision-makers must review whether such a system would suit the particularities of the EU market. One consideration is whether a locational marginal pricing system is appropriate for a market dominated by bilateral transactions as the EU market is.

A common misconception about locational marginal pricing is that it is necessarily built around a 'pool', or central buyer, model of power market operation. In fact, in US markets, most transactions are bilateral and can result in the submission of fixed power schedules (or schedules with incremental and decremental bids) to the system operator. This has also been the experience of the Nordic zonal pricing scheme. Prices are, of course, set by marginal bids that allow quantities to vary at a price, but all long-term energy transactions continue to be pursued bilaterally.

Locational marginal prices provide transparent and verifiable bases for settling transmission charges for bilateral schedules; for settling deviations from schedules; and for pricing future transactions. A liquid market also provides a means for improving efficiency, by allowing parties to buy their way out of a deal by accessing the spot market. For instance, if a generator has contracted to sell 1000 MW to a load in another area, if the locational marginal price at the generator is less than its marginal cost, the generator can profitably shut down its plant and purchase cheaper power from the spot market.

The availability of financial transmission rights can also facilitate bilateral transactions by allowing one of the two parties, or both, to change points of delivery to preferred buses (or sets of buses). They can also lower risk to investors in generation; if a new generating plant secures Financial Transmission Rights (FTRs) between its location and either the location of its consumers or a trading hub, then uncertainty about what revenue it will receive for its output and what transmission charges it will pay may be satisfactorily reduced.

Thus, locational marginal pricing should be viewed as supporting, not displacing, bilateral transactions.

2.3.3 Costs of Changing Power Market Design

Significant changes can be expensive – replacing the electricity pool in England and Wales with the New Electricity Trading Arrangements was estimated to cost €1 billion and arguably raised operating costs by requiring more complex trading and contracting

arrangements. The set-up costs of devising the contractual arrangements to ensure that incumbents are compensated for changed patterns of revenues while not receiving excessive windfalls should not be under-estimated, and the subsequent disputes and their resolution are likely to be costly.

On the other hand, the sooner the change is made, the more short-lived and fewer the plants that need to be compensated for changes. If we wait until a large volume of new capacity comes on the system (and high levels of investment are contemplated in most EU countries), and if we wait until the strains of operating the current system become intolerable, the costs might rise considerably.

2.4 Design Elements for a Locational Marginal Pricing System

2.4.1 FTRs to Mitigate Price Risks under Locational Marginal Pricing

Generators located in export-constrained areas and load located in import-constrained areas would naturally be concerned about erosion of revenues or increases in purchase costs, respectively, under a locational marginal pricing system. If such a system provides, on balance, more benefits than costs to society, it should in theory be possible for parties who are worse off to be compensated by other market parties who benefit from locational marginal pricing. The allocation of FTRs is one means of accomplishing this transfer without distorting incentives for efficient system operation.

For example, a generator fearing lower prices for its output under locational marginal pricing could be granted FTRs from its point of production to a trading hub or other node. Similarly (and more commonly in the US), load might be given rights from supply regions' points of consumption as a hedge against higher prices due to congestion. The allocation of such free rights should be subject to the so-called 'simultaneous feasibility' constraints that are necessary to ensure that a system operator's congestion revenues will cover its payments to rights holders. Of course, establishing the rules for distributing such valuable rights is a delicate process that determines whether stakeholders support the power market design change.

Another concern with locational marginal pricing is that prices might be more volatile than zonal prices, or that the need for specific locations of delivery could make markets illiquid. Again, FTRs are the major instruments that US markets use to deal with this issue. A point-to-point FTR is the right to be paid the price difference between two loca-

tions (Bogorad and Huang, 2000) [11]. By acquiring a suitable set of rights, a purchaser or seller of power can ensure that they will pay the spot price at the location they desire, rather than where they are physically scheduled. For instance, market parties may prefer to settle at the price at a market trading hub (which might be a single bus or aggregation of buses); they can then hedge the price difference between their bus and the hub by holding a mix of FTRs. By having a bundle of FTRs to several different buses, volatility of net proceeds from a transaction can be dampened. Another way that some ISOs have dealt with this issue, at least in the case of load, is to charge a spatially averaged price rather than specific locational marginal prices; however, that solution lessens the value of demand response as a means to manage congestion.

Under existing FTR systems in the US, the type of generators and loads that can best protect themselves from price risk are those with constant or regularly varying MW outputs/requirements. FTRs are generally defined for blocks of hours (e.g., peak hours) over a period of a month to a year and can be shaped to (somewhat) match average daily load or generation patterns.

However, such FTRs may be a poor hedge for the congestion risks of intermittent renewable generation, whose patterns are not predictable. New ideas are being discussed in the US for defining FTRs whose quantities will match the output of intermittent generation – so-called 'dispatch-contingent FTRs' (Bogorad and Huang, 2005). This would introduce challenges, such as the definition of the complementary right (higher quantities when intermittent generation is low). However, thermal generators who must increase output when wind is unavailable, such as Scottish thermal generators, might be more interested in such complementary rights than in traditional fixed MW FTRs.

FTRs to Mitigate Rent Re-Allocation Issues

As short-term demand elasticities in power markets are low, market design changes can result in larger rent re-allocations. This has been particularly problematic in Great Britain when attempting to reflect marginal transmission losses in local wholesale prices, where Scottish generators stand to lose hundreds of million euros and southern generators to gain slightly more. The Scottish generators have successfully taken the regulator to judicial review in response to attempts to impose transmission losses in the dispatch order and compensation, while a contractual compensation scheme might

11 Duthaler and Finger (2008) describe the potential application of FTR systems to the EU. Lyons et al. (2000) introduces the mechanism.

have allowed the gains to be distributed to all with the power to veto the changes. Hence, the creation and allocation of financial transmission contracts is seen to be a key component of strategies for market design changes, as they can constitute a transition mechanism as described above in Section 2.4.1.

2.5 Transitioning to a Locational Marginal Pricing System

In contrast to the US, EU Member States are not part of one country, so major reforms with European dimensions either have to be agreed upon, promulgated as Directives and written into local law, or negotiated, in which case all Member States need to believe that they will individually benefit. Even if a new market design were to be written into a new Directive, it would still need to be acceptable to Member States. This suggests the following important principle to guide any changes that impact revenue streams (as will be the case with most market design changes): the changes should be designed so that on an ex-ante basis each Member State enjoys a net benefit or no adverse effects.

2.5.1 Institutional Options to Implement Locational Marginal Pricing

The implementation of locational marginal pricing in the US has proceeded on a regional basis. Thus, although locational marginal pricing is used from Chicago all the way to the northeast-most state of Maine, there are four different ISOs and four different locational marginal pricing systems involved. Because many small but significant differences and incompatibilities arise in the different systems, this results in so-called ‘seams’ issues. Barriers to trade have arisen and have proven stubbornly difficult to overcome. As a result, operations within a region have become more efficient, but trade between regions can stagnate or even shrink.

There are two solutions to this problem. One is integration of regions into a single nodal pricing region with compatible pricing systems, though jurisdictional jealousies or software limitations may block this route. While PJM has succeeded in expanding its footprint very successfully (with large economic benefits, Mansur and White, 2009), the California ISO has proceeded in the other direction, losing WAPA (a federal agency whose facilities have been withdrawn from the ISO). The northeastern US ISOs (NYISO, ISO-NE, and PJM) discussed a merger in the early 2000s, but practical considerations caused discussions to end before a resolution was reached.

Another approach is coordination of nodal pricing in adjacent systems. This is possible in theory. For instance, Kim and Baldick (1997) and Baldick (2007) describe the use of

distributed computation of the optimal power flow problem to coordinate nodal pricing systems in different regions (see also Chen et al., 2004).

After the failure of the discussions among PJM, ISO-NE, and NYISO about a possible merger, those ISOs have worked on small improvements, such as making gate closures consistent, sharing information on internal system status, and implementation of scheduling systems that allow scheduling simultaneously across two systems (PJM, 2005). However, the process is very slow, and in some cases has moved backwards. For example MISO and PJM failed for some time to resolve PJM's concerns about MISO exports being scheduled to high-priced PJM import nodes but actually arriving at low priced-ones (Harvey, 2008).

2.5.2 Process for Introduction of Locational Marginal Pricing

In the US, locational marginal pricing was adopted after zonal pricing was tried and found wanting because of unacceptable dispatch inefficiencies, income transfers due to inc-dec games, and operating difficulties caused by large amounts of redispatch. This happened in the Texas, California, and PJM markets that started with zonal systems and switched to locational marginal pricing systems. MISO, ISO-NE, and NYISO saw those problems and decided to do it right the first time.

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3 Balancing and Intraday Market Design: Options for Wind Integration

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3.1 Introduction

The growing share of wind and other intermittent generation sources in the European power supply increases the uncertainty about power production in day-ahead and longer-term predictions[13]. More accurate forecasts closer to production time reduce this uncertainty. This paper provides six criteria that power market designs need to satisfy in order to allow market participants and system operators to make full use of this information and thus limit the uncertainty and facilitate integration of intermittent renewable energy sources at lower costs and larger volumes, while also increasing system security.

European Member States and the Commission have committed in the EU Renewables Directive to the large-scale deployment of intermittent renewable energy sources across Europe and are assessing barriers that could cause delays and increase costs. The paper addresses the three distinct types of markets currently used by most EU Member States: 1) Day-ahead markets that clear the day before power is provided; 2) Intraday markets that allow for adjustments after the closure of the day-ahead market until gate-closure, typically about one hour before real time; and 3) Balancing markets that are used by the system operator to resolve remaining imbalances. How does their design and limited integration across time and countries, constrain the full use of flexibility that generation, transmission, and demand can offer, and what options exist for improvements?

Historically, balancing markets have been the only markets to provide reserve and response operations. System operators contract this reserve and response capacity in day-ahead and longer-term markets with generators to provide flexibility that can be

12 We thank Julian Barquin, Christian Nabe, and Benjamin F. Hobbs for all their valuable comments and input.

13 In this paper we focus on market design issues for reserve and response markets both within a country and between European Member States. Glachant and Finon (2009) further point out, that wind energy integration into electricity markets creates economic challenges on various additional fronts: support scheme design, strategic behaviour in the presence of large-scale wind energy, and new methods for assessing the economic value of wind power.

called upon on short notice to balance the system when forced power plant outages or load prediction errors occur. Balancing was only necessary for events of small probabilities (power station failures) or for small volumes (as in the case of load prediction errors); the amount of reserve capacity contracted was thus large compared to the small share of actual electricity requested. Balancing services were provided nationally, or in the case of Germany, within the region of the TSO. Mutual support between regions was restricted to emergency situations, such as unexpected power plant failures, and not remunerated (only energy that was provided had to be returned). Most power markets imposed penalties for deviations from day-ahead schedules to limit demand for balancing power.

In recent years renewable energy and newly installed wind power have prompted additional demand for reserve and response operations. This demand arose predominantly due to the uncertainty of day-ahead forecasts for renewable feed-ins. This trend will continue as EU Member States increase the deployment of wind power and other intermittent renewable energy sources to deliver the 20% renewable target formulated in the European Renewables Directive of 2008. Therefore, intraday and balancing markets need to be adjusted to allow the TSOs to appropriately respond to increased uncertainty.

The forecast error for wind decreases distinctly with a shorter lead-time (DENA, 2005; DENA, 2010; Focken et al, 2002; Von Roon and Wagner, 2009). In markets unable to adapt to changing wind forecasts during the day, large volumes of real-time balancing are required, and because of the high uncertainty of wind 24-36 hours ahead of physical feed-in, a significant amount of balancing reserve capacity is required. EWIS (2010) and Tradewind (2009) quantify the resulting additional costs for electricity generation due to the increased start-up and part-load costs to provide balancing power.

Different studies (Muesgens and Neuhoff, 2002; Tradewind 2009) point out that system costs for balancing wind uncertainty can be significantly reduced if an improved market design allows for optimisation of dispatch across the entire system based on wind forecasts with lead-times reduced to 1-4 hours ahead of physical dispatch. In addition, the design of markets for intraday balancing and markets for improved congestion management can also increase efficiencies.

The EU has made some progress towards integrating power markets, but today's intraday and balancing market designs are far from a fully efficient and harmonised market. In the third Energy Package, a path for further regulatory harmonisation was laid, which aims to foster a common energy market. The paper provides criteria that the market design must satisfy in order to support the large scale integration of renew-

ables. It illustrates the value and importance of closely integrated operation and market designs for the European electricity system.

This paper explores whether the power market designs currently used in European countries offer incentives for market participants to realise the technological opportunities that exist. We assess whether the designs in several countries allow for the flexibility to adequately handle wind intermittency, in particular whether they:

- Facilitate system-wide intraday adjustments to respond to improving wind forecasts, to ensure that the least cost generation capacity provides power and ancillary services.
- Allow for the joint provision and adjustment of energy and balancing services; to reduce the amount of capacity needed to provide balancing services and to operate on part load.
- Manage the joint provision of power across multiple hours; a broader set of actors can contribute energy and balancing services in day-ahead and intraday markets if they can coordinate sales across adjacent hours (thus more accurately reflecting technical constraints of power stations like ramp-up rates or start-up costs).
- Capture benefits from international integration of the power system; the transmission network is the most flexible component of the power system, but requires fully integrated intraday and balancing markets to replace more costly generation assets and enhance system security.
- Integrate the demand side into intraday and balancing markets; creating incentives and systems that allow the demand side to fully contribute to the available flexibility.
- Effectively monitor market power; to ensure that cost-reflective intraday pricing bids encourage efficient dispatch choices and 1.) Limits costs for integrating intermittent renewables, 2.) Reduces the risk for market participants exposed to intraday adjustments, and 3.) Limits the need for utilities to balance within their portfolio and thus increases participation.

This paper is structured as follows. The uncertainty of wind forecasts and opportunities to reduce it are discussed in Section 3.2. Section 3.3 discusses the flexibility of the power system to deal with the uncertainty. In Section 3.4, the above six criteria for making use of the flexibility of the power system and opportunities to reduce wind uncertainties are introduced; a critical assessment of which is explored in relation to the effectiveness of current European power market designs. Section 3.5 describes recent EU developments and discusses possible next steps; with concluding remarks in Section 3.6.

3.2 Uncertainty of wind forecasts, and opportunities to reduce it

The power system has to deal with three main sources of uncertainty: demand uncertainty and load prediction errors[14], failure of power plants, and the uncertainty of wind. Figure 3-1 illustrates that the aggregate uncertainty about the balance of power supply and demand increases with uncertainties of the individual components.

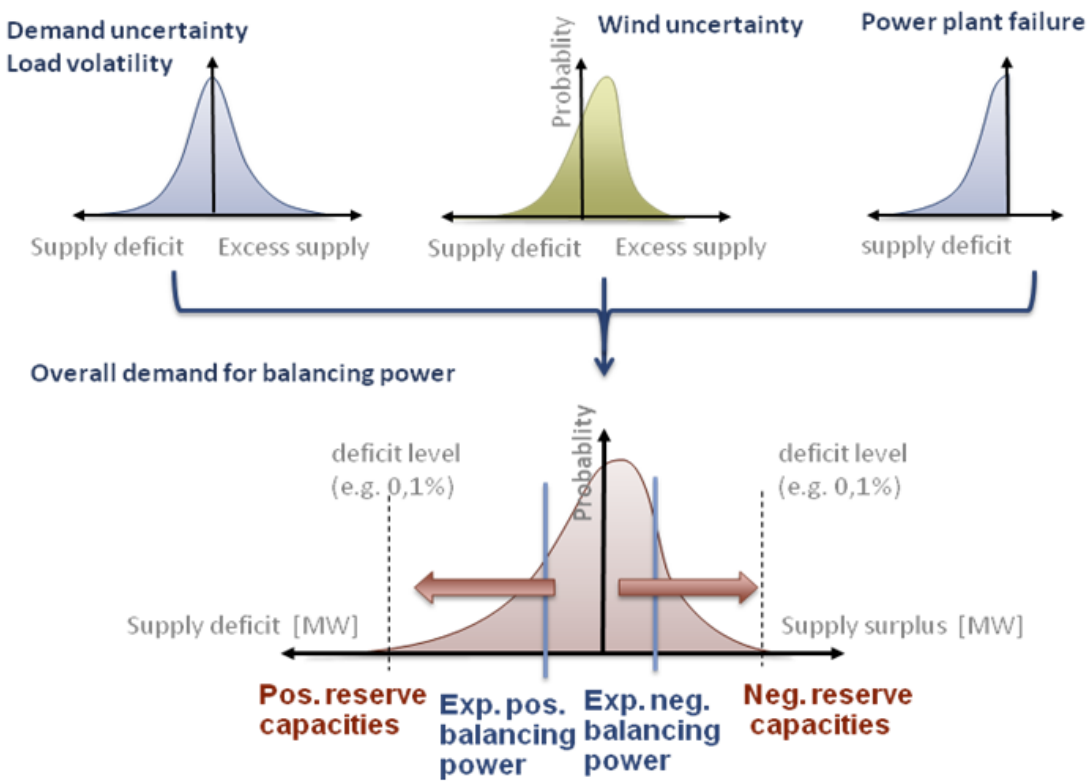

Figure 3-1: Forecasting errors from demand uncertainty, wind uncertainty and power plant failure[15]

The following factors need to be considered when evaluating the impact of wind uncertainty on the power system:

14 Demand variations can be further distinguished as: 1.) Load forecast errors, i.e. the deviation of actual demand from the forecasted load of electricity, 2.) Stochastic noise of the electricity demand arising from the deviation of the load level of each second from the quarter-hourly load average, and 3.) Leaps of electricity supply due to early or late delivery of electricity through a scheduled power plant.

15 Similar to DENA (2005).

- Uncertainty about wind projections decline during the last 24 hours. The demand and supply uncertainty that has to be balanced in real time can be reduced significantly if additional information and updated wind forecasts within the last hours before physical dispatch are used effectively.
- The aggregate uncertainty is less than the sum of the individual uncertainties as long as errors in wind projections, demand projections, and power failure stations are not fully correlated (Dany and Haubrich, 2002). The factor that can contribute the biggest real-time imbalance of supply and demand is likely the failure of large power stations or transmission lines. If uncertainty in predictions of wind output is smaller than uncertainties about other factors, it might only have a small impact on real-time balancing needs.

There are three ways to reduce uncertainty.

3.2.1 Improve the accuracy of wind forecasts

The accuracy of the wind power forecast has significantly improved in recent years. In Germany, the 24h forecasting error[16] for the aggregate output from German wind turbines was significantly reduced from 6.1% in 2007 to 5.6 % in 2008 (Von Roon and Wagner, 2009). Future improvements of wind forecasting can be obtained based on improvements of the available wind models as well as their coupling. Further improvements of wind models will lead to an increase in forecasting accuracy in the coming years. The German DENA II study (DENA, 2010) predicts forecast errors onshore might be reduced by as much as 41% by 2020.

Despite this expected improvement in wind forecasts, the DENA grid study (DENA, 2005 and Bartels, 2006) shows that the uncertainty about predicting the absolute volume of wind output day-ahead will increase as wind penetration grows. Thus the demand for positive and negative balancing power, primarily for the time frame >15 minutes will likely increase if the current power market designs are maintained (Figure 3-2)[17]. In short, improved wind forecasts alone will not be enough to reduce uncertainty sufficiently - we need to consider other options for reducing or managing uncertainty.

16 Root mean squared error (RMSE) of the total installed capacity

17 Source: Own graph, with data from Hasche B. (2007) and Von Roon and Wagner (2009)

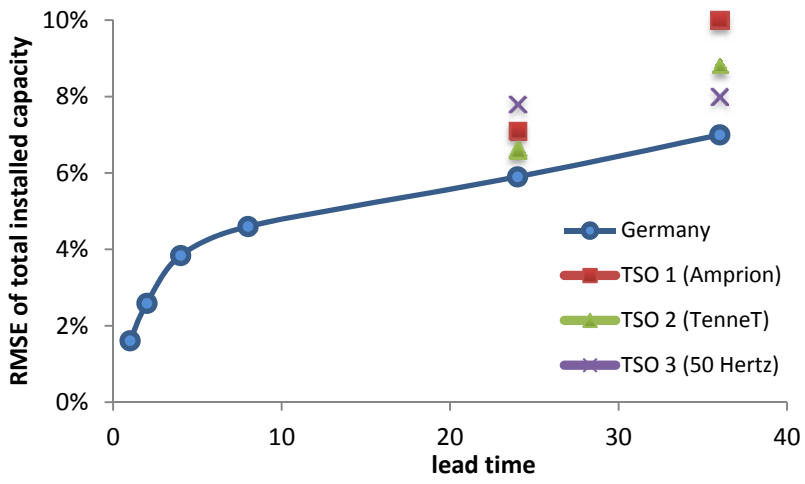

Figure 3-2: Increasing wind uncertainty depending on the forecast horizon for Germany and three transmission zones[18].

3.2.2 Reduce the lead-time for wind forecasts through intra**day markets**

The lead-time of wind forecast strictly determines forecast accuracy. When the wind forecast changes from a day-ahead forecast to an intraday forecast with a 1-4 hour lead-time, the errors decrease drastically. Figure 3-2 displays the percentage of the total installed capacity for a 1-,2-,4-,8- hour and day-ahead forecast for Germany in 2008. The average forecast error (RMSE) is reduced to 3.8% of the installed capacity compared to 5.9% (7.0%) of the 24h (36h) day-ahead forecast. (Smeers, 2008; Von Roon and Wagner, 2009)

3.2.3 Average wind output over larger areas

Large wind areas can reduce uncertainty in the overall wind feed-in. The correlation of wind feed-in and uncertainty strongly depends on the distance between wind farms (Figure 3-3) and therefore also on the size of the investigated area. This effect can be observed even for significantly large areas. The integration of the German transmission system operators (TSOs) into one market in 2009 provided a good example. The day-ahead (24h) forecast error (RMSE) for each of the four TSOs was between 6.6% and 7.8%. Bundling the region reduced the forecast error to 5.9% (Figure 3-2).

18 Estimation for Germany based on Von Roon and Wagner (2009), DENA II (DENA, 2010)

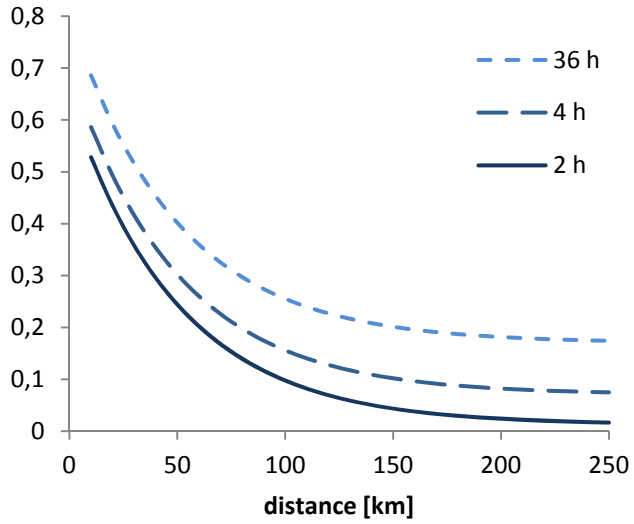

Figure 3-3: Correlation of two wind parks depending on the distance of the wind parks and time of forecast[19]

This paper focuses on these last two opportunities and thus investigates the institutional perspective: reducing lead time through 1) intraday markets and by 2) increasing the size of wind areas.

3.3 Flexibility of the power system to deal with the uncertainty

In addition to the opportunities to reduce wind uncertainty described in Section 3.2, uncertainty will remain a decisive part of the system and the power system offers means of flexibility to address uncertainty. The power system can respond to deviations between demand and supply by adjusting demand, adjusting supply, or using storage capacity. Three factors determine the flexibility of the power system to respond to uncertainties.

3.3.1 System flexibility increases with increasing lead time

The lead time that is available to pursue system adjustments determines the generation and demand technologies that can respond. Within the one hour timeframe, the system offers three types of response: primary response is available to match unpredicted deviations in time frames from 30 seconds to 15 minutes, secondary response is available within 5 minutes and tertiary response requires lead times from 15 minute to

19 Graph: Own. Calculations based on formula and data from Hasche B. (2007).

1 hour. Only gas turbines, hydro plants, and pump storage have the technical capacity to provide a full start within 15 minutes. Coal and nuclear power stations must already be operating on part load to be able to contribute short-term responsiveness.

With lead times of one hour to four hours it is possible to start-up combined cycle gas turbines and coal power stations, but longer lead times are necessary to start up nuclear power stations. With increasing lead-time more types of generation assets are available to adjust their output.

3.3.2 Interaction between balancing and energy markets influences system flexibility

Many generation assets can only adjust their output close to real-time, if they are already operating (nuclear, lignite, coal, and certain gas power plants). Only the plants that are operating can provide negative balancing reserve, while these plants have to operate in part-load to be able to provide positive balancing power[20]. Moreover, a power plant is only willing to decrease its energy sales to provide reserve capacities for balancing markets if the expected price it gets for actually providing those reserves is able to compensate for the foregone margin (price minus marginal cost) in the energy market.

Adjustable capacity is therefore highly dependent on the commitment of conventional generation units as part of energy sales in day-ahead and longer-term markets and the ability to adapt this day-ahead commitment to the changes in the market within the last 24h before physical dispatch. Therefore, when information on the wind-output increases during the day, reserve capacity no longer required in the balancing market must be made accessible within the intraday electricity market. At the same time it must be possible to react to changes in the electricity market by changing reserve capacities to suppliers that are no longer needed and able to offer their capacity to the balancing markets at lower costs.

Market design needs to allow generators to adjust their energy production and provision of balancing services in a joint bid, so that they can contribute to an efficient system operation.

20 Power plants such as gas turbines that can provide positive balancing power with a cold start of the turbine often face high variable cost of operation.

3.3.3 Interaction with transmission constraints

In the current European power market designs, transmission capacity is usually allocated for long-term and day-ahead energy sales. Some transmission capacity is reserved to ensure system stability in the case of unexpected failures of power stations and transmission equipment. Only in limited instances, however is it possible to reschedule power flows between countries during the day. This creates a constraint for intraday optimisation of the power system – focusing on the generation capacity that is locally available rather than using the capacity that is distributed across the entire system. As seen above, the closer to real time the scheduled output of generation has to be adjusted, the fewer generators are available that can provide flexible capacity. This increases the costs of dealing with uncertainty, compared to a coupled reserve and capacity markets, because less suitable generators have to be selected.

In addition, with fewer generators providing flexibility, the likelihood that they can exercise market power increases. This results in distorted prices, which increases costs and potentially creates inefficiencies in the process of balancing the system. Options to increase supply of flexibility within a region are limited, though we can consider ways to enlarge the region and pool of potential players. A coupling of national balancing markets will then again increase market efficiency and reduce potentials to exercise market power.

3.4 The challenges for the current power market system

The current EU power market designs are analysed here to assess how well they make use of the opportunities to limit wind forecast uncertainties that were identified in Section 3.2 and of the technical flexibility to deal with these uncertainties identified in Section 3.3. Three specific questions translate into six criteria for assessing whether power markets make use of opportunities to reduce wind uncertainty and leverage power system flexibility:

Does the market design make full use of information as it becomes more accurate during the day?

1. Can power system dispatch be adjusted during the day? (Section 3.4.1)
2. Can the requirements for, and providers of, balancing services be adjusted during the day? (Section 3.4.2)

Will all actors that can technically respond be fully included?

3. Are the current power market designs suitable for power stations that can only operate for several hours at a time, and might thus be excluded in systems where bids are submitted hour by hour? (Section 3.4.3)

4. Does the international integration of energy markets facilitate the provision of flexibility by actors in neighbouring countries? (Section 3.4.4)

5. To what extent do incentives and systems exist to make full use of the flexibility provided by the demand side? (Section 3.4.5)

How transparent is the market?

6. Is it necessary and possible to identify and monitor the potentials and exercise of market power? (Section 3.4.6)

3.4.1 Intraday adjustments to reduce wind forecast uncertainty in balancing markets

Traditionally, power markets focused on long-term contracting between demand and supply and provided a platform for day-ahead trading (power exchanges) to match demand and supply. Any deviations between demand and supply contracted at the day-ahead stage and subsequently realised were adjusted by the system operator with energy from the balancing market. Figure 3-4 illustrates the provision and actual use of balancing energy in a market without intraday trading. In this example, the day-ahead forecast in t-24 underestimates the actual wind load in t0. The TSO must contract positive and negative capacity reserve for balancing at the level of wind forecast uncertainty that persists in t-24. In the example in Figure 3-4, the provision of reserve and response capacity is unable to adapt to improved forecasts. In t-1, large amounts of positive and negative balancing reserve capacities still have to be withheld from the market. The deviation of wind output from day-ahead forecasts is then balanced close to real-time within the last hour before dispatch (t).

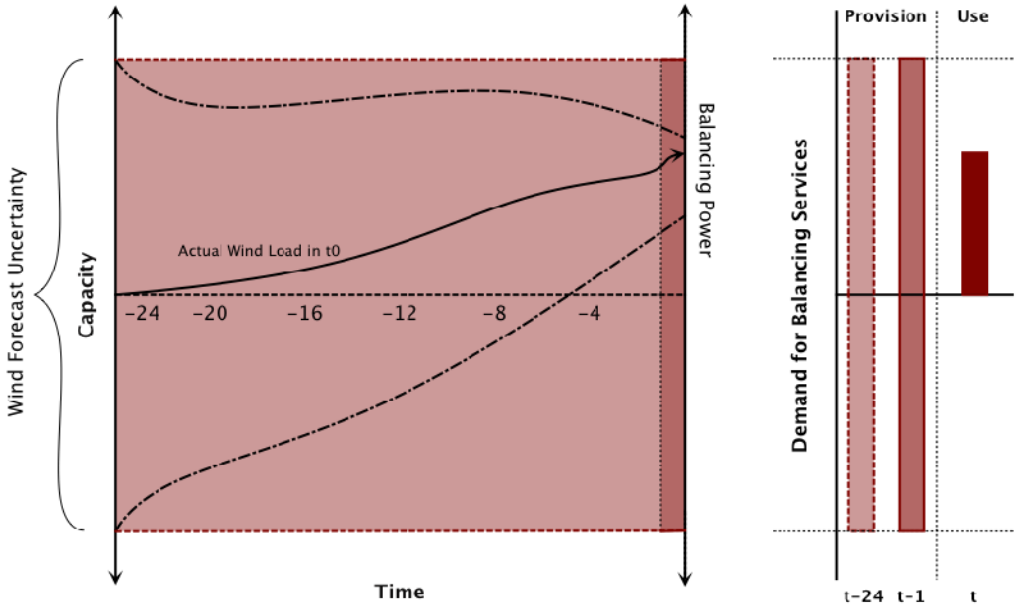

Figure 3-4: Example I - Wind forecast uncertainty, actual wind feed-in, and balancing services in a market without intraday trading.

During the day, the improved wind-forecast estimates a higher supply of wind for the specific hour t0. With the improved wind forecast, the expected deviation and demand for positive and negative balancing capacity also decreases (dotted line). Recognizing this benefit, various European countries have established intraday markets to allow for an adjustment of dispatch during the day. Still, there is a large variety of power market designs, some more effective than others, and whose differences make it difficult for inter-region market coordination.

In the UK, all generators, including wind turbines, have to submit their final schedules to the TSO half an hour before real time (gate closure time). Any resulting or subsequently emerging deviations between demand and supply are managed by the TSO. Thus, market participants can, in principle, use bilateral trading and power exchanges for intraday adjustments. In practice, however, all wind turbines are owned by or managed as part of the portfolio of incumbent generators and most intraday adjustments and pooling of uncertainties are pursued within this limited portfolio rather than across the power system.

In Germany, the responsibility for balancing wind output is allocated to the TSO. The joint ownership of many TSOs with generation companies providing balancing services created incentives to maximise the acquisition of costly balancing services, as costs can be passed to consumers through network charges.

Until 2008 wind uncertainty could not be traded in the intraday market. Weber (2009) also points out that liquidity in the intraday markets was small. Starting in 2009, however, TSOs have been required to also use the intraday market for procurement of services to balance the uncertainty of wind forecasts. As a result, the improved forecast accuracy during the day now allows the TSO to trade deviation in wind forecast from the day-ahead forecast in the intraday market (See Figure 3-5). Demand for balancing power in t decreases to the deviation between the forecast in t-1 and physical supply in t. At the same time the volume of positive and negative balancing services that have to be contracted day-ahead reduces to the wind uncertainty between t-1 and t.

Figure 3-5 indicates that these improvements in market design lead to less demand for overall reserve capacities. In addition, part of rescheduling of the power plants necessary to cope with wind uncertainty is shifted from balancing markets towards the, in general, more flexible intraday market. Since 2009 the liquidity in the intraday market significantly increased, due to the demand from TSOs.[21]

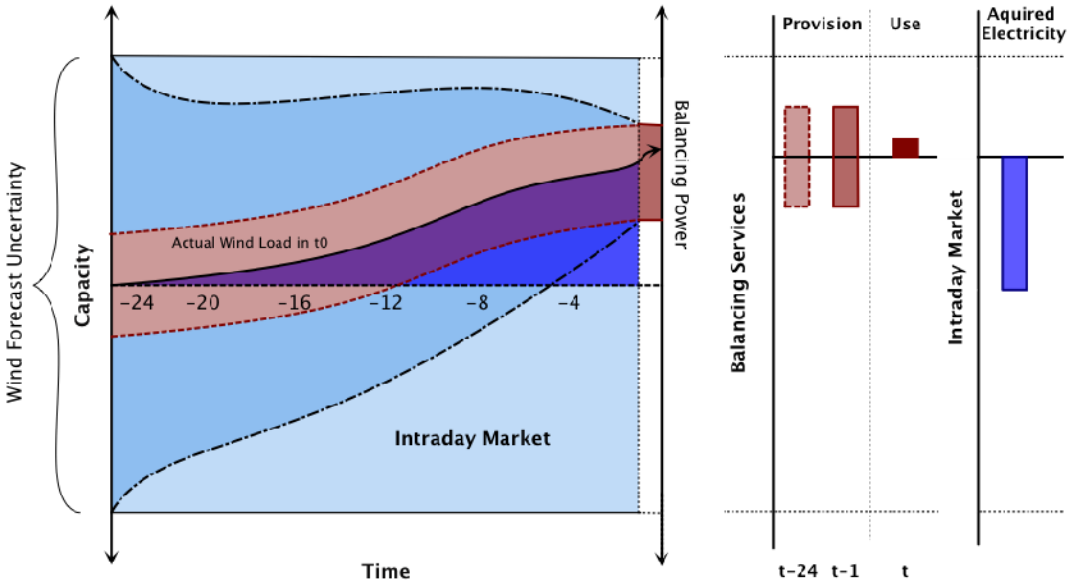

Figure 3-5: Example II - Wind forecast uncertainty, actual wind feed-in, and balancing services in the German market setup with intraday trading

21 The question of Weber (2009) remains: are intraday markets sufficiently liquid at all times? Therefore can a capacity market, such as the balancing market, be fully replaced by energy-only markets (as it is the case of intraday markets).

Spanish wind generators have two ways of being remunerated[22] (Royal Decree RD 661/2007 and de la Fuente, 2010): through a regulated feed-in tariff regime or by being paid a premium over the day-ahead price. In the first case they are paid a fixed price of €/MWh times the produced energy. In the second case they are paid a premium over the day-ahead price times the produced energy as long as the resulting price is between a floor and a cap price. Wind generators must remain at least one year in the chosen regime, although arbitrage between the regimes has been reported. The wind generators in both regimes must submit a production program to the TSO at gate closure of the day-ahead and intraday markets[23]. In the case of deviations, wind generators are penalized according to specific formulae for both regimes[24]. The TSO operates six consecutive intraday clearing auctions that allow for a full rescheduling of power plants and optimisation of the system in line with information about demand and supply balance. In addition, as all interactions are focused on six intraday auctions, they exhibit more liquidity than observed in other European markets with continuous intraday trading. This market solution has allowed the TSO to keep the volume of required balancing services constant in the last years, despite the large penetration of wind power in Spain and the limited interconnection with neighbouring countries.

Key issues with the current EU system related to intraday trading: market liquidity, regulatory framework and transparent wind forecasts.

1. Liquidity of the markets

The key concern when implementing intraday markets is whether both balancing and intraday markets can remain sufficiently liquid. Markets are defined as liquid if the number of bids and the amount of trading activity is high enough to create transparent prices and ensure that individual actors only have small impacts on the price formation. In 2009 Weber (2009) pointed out that intraday markets might not be an improvement per se due to a lack of liquidity. Using trading volume in a market as the indicator for liquidity, Weber finds that for 2008 the intraday markets in Germany and other selected

22 Wind generators operating prior to 2007 can also be remunerated according to a specific regime defined in the Royal Decree RD 436/2004 until 2012, in which year they must choose one of the regimes described in the main text.

23 However, the TSO uses its own wind generation forecast software for operational purposes

24 Specifically, wind generators in the feed-in tariff are not penalized if deviation is less than 20% of the forecast. If this figure is exceeded they pay a penalty proportional to the amount of the deviation. Wind generators in the premium regime pay a penalty in the case that their deviation is against the system deviation and a zero penalty otherwise, according to formulae similar to those used in most European systems.

countries were not sufficiently liquid. Starting in 2009, TSOs in Germany have been committed to balancing their procurement for uncertainty of wind forecasts through the day-ahead and intraday market, and the liquidity of the intraday markets substantially improved when this new market setup was implemented.

2. Regulatory framework to support TSOs in intraday adjustments

If TSOs are responsible for balancing deviations of intermittent generation from output, as they are in Germany, a clear regulatory structure is required. One approach is the use of incentive schemes, which expose the TSO to some of the costs for system balancing (or sharing profits from savings on balancing costs). Thus the TSO would be motivated to reduce costs that would otherwise be fully passed on to consumers.

The U.K. has successfully applied incentive schemes for the TSO to minimise system balancing costs (not related to wind which is privately balanced). This has created three sets of difficulties. First, to maximise long-term benefit from future negotiations of incentive schemes, the TSO has had strong incentives to improve its bargaining position by limiting transparency. Second, generators in the UK have complained about non-transparent contracting choices by the TSO, reducing trust and certainty. Such sentiments undermine efforts to integrate wind power into the dispatch of power systems and to provide transparent information for planning and permitting processes of transmission expansion. Third, the U.K. is an island, so incentives for NGT (the national TSO) have limited impact on neighbouring TSOs. In the case of continental European TSOs, incentives to minimise balancing costs for individual TSOs could lead to behaviour that shifts costs and responsibility to neighbouring countries at the expense of system efficiency and security.

With difficulties relating to incentive schemes on TSOs, the regulatory solution is a combination of (i) minimising exposure to market outcomes, e.g. through clear unbundling of system balancing obligations from other business activities, and (ii) providing clear rules for as many decisions as possible, while retaining the level of discretion necessary to allow responses to unexpected system circumstances. As bilateral contracting is in its very nature based on discretionary choices associated with each negotiation, auctions have become the preferred market interface in such environments. The Spanish example is a starting point, and many power systems in the US (e.g. PJM) have further refined the approach and use rules that are guided by the technical constraints of the system.

3. Transparent and accessible wind forecasts

Spain implemented an RES control centre (CECRE) that overlooks the wind feed-in and provides aggregated forecasts for the coming 48 hours. All wind farms exceeding 10 MW must be connected to this control centre and provide continuous information on status and actual feed-in. Additionally, CECRE bundles a variety of long term forecasts (up to 10 days) and detailed forecasts for the next 48 hours. This allows for clear market monitoring of installed wind power and for a high penetration of special regime generation in the system, which ensures security of supply. CECRE has the ability to centrally trigger wind curtailment in times of need.

3.4.2 Joint provision of energy and balancing services

Energy and balancing services are both provided by power stations; decisions about one affect the other. For example, a power station that is operating at full capacity cannot provide upward balancing services and a power station that is not operating cannot provide downward balancing. Furthermore, for most power stations it takes time (minutes to hours) to get started, and in these cases only power stations that are providing some power can also offer balancing services.

Generation companies therefore have to jointly decide on their provision of energy and reserve and response services to the market; they must coordinate these services between spot, intraday, and balancing markets. If it is likely that upward balancing energy will be required, it might be efficient to operate coal power stations on part load so as to provide that service. If the likelihood is lower, it might be (at times of low coal and CO2 prices) be cheaper to operate one coal power station at full load, and start up a gas power station if required.

In the past, this was of limited concern. Usually the demand-supply balance did not change very much between different weekdays, so actors in the market could learn from the realisation in previous days so as to optimise their choice. With increasing penetration of wind power, however, the net demand for energy (demand – wind output) and the demand for balancing services will vary from day to day; coordination to reach an efficient market equilibrium (many local equilibria may exist due to non-convexity of unit commitment choices) is more complex.

Key issue with the current EU system: Ability to optimize between balancing and energy markets

The main difficulty for market actors is that in most European power markets, power-plant owners must commit their capacities day-ahead either to spot/intraday trading or

to balancing services. Changing this commitment closer to real-time is not possible. Smeers (2008) points out that the current designs of day-ahead, intraday markets and the balancing system in the EU are based on three different organizational schemes. Smeers argues that "these multiple arrangements violate the finance view that day-ahead, intraday and real-time are just different steps of a single trading process and hence require a single trading platform."

Table 3-1 shows the current market implementation in Germany. It must be pointed out that even though TSOs trade in the intraday market, the power plants contracted to be available for the provision of balancing services (for power plant failure and wind uncertainty between t-1 and t0) cannot be changed. The primary reason is that an intraday market for reserve capacities is missing.

An increasing wind feed-in will lead to a reduction of conventional power generation. The power plants that offer to reduce electricity supply, e.g. through part-load operation, would be able to provide positive balancing power for the same hour at a very low cost but will in practice be unable to provide their services due to the given market design. Instead, balancing availability is likely to be provided by units with low day-ahead capacity costs (gas turbines) and high variable costs, resulting in subsequent increases in balancing costs.

Table 3-1: Market actors and traded products in reserve and response markets[25].

			Time of Trade		
Type of Market	**Traded Products**	**Market Actor**	**Day-ahead**	**Intraday**	**Real-time**
Markets for reserve capacities	Wind uncertainty in t-1 until t and real-time	TSO	Day-ahead balancing market	No trading of balancing capacities	Real-time dispatch of balancing power
	Reserve capacity for power plant failure, demand forecast uncertainty and intra-hour load volatility	TSO			
Electricity markets	Wind uncertainty in t-24 until t-1	TSO	Day-ahead spot market trading	TSO trades in intraday market	
	Unforeseen power plant outage (after t-4), deviations in the supply schedule	Producer		Trading	
	Intraday changes in demand	Industry		Trading	

25 Graph is based on the German market design (own graph).

At present it appears to be difficult to implement an intraday market that efficiently processes both energy and bids for balancing capacity. The difficulties arise primarily because balancing services are acquired by the TSOs, while electricity in spot and intraday is traded on the power exchange and bilaterally. Alternative options for joint provision of energy and balancing/intraday services are:

- A fully bilateral market that allows actors to jointly trade energy and balancing services. It is difficult, however, to see how market participants could match their supply/demand to a complex set of energy/balancing products with specific temporal and spatial requirements.
- Pool type trading arrangements. These centralised market systems facilitate joint trading through joint optimization, as is the case in all the U.S. ISO markets such as in PJM[26]. Intraday market clearing platforms in the PJM system differ from the bilateral approach in current European intraday trading schemes. The system operator calculates close to real-time an optimal dispatch based on firm schedules submitted and flexible bids provided by market participants. These bids can include technical parameters like ramp rates and part load constraints to allow the system operator to make full use of the available generation assets. This approach ensures high liquidity for short-term optimization of the system. Day-ahead (and intraday) markets are pursued using the same market-clearing algorithm for dispatch and transmission allocation. This creates inter-temporal consistency and avoids gaming otherwise often observed between day-ahead and shorter term markets. Operating reserves and energy are co-optimized, and start-up and minimum load costs are considered in the optimization and can be recovered through side payments if market revenues are insufficient. While long-term contracting remains bilateral, most day-ahead and intraday activity is pursued on the centralized platform of the independent system operator (ISO) and not bilaterally as is the case in most European markets.

26 One of the largest electricity market systems in the U.S. comprising all or parts of 13 states and the District of Columbia.

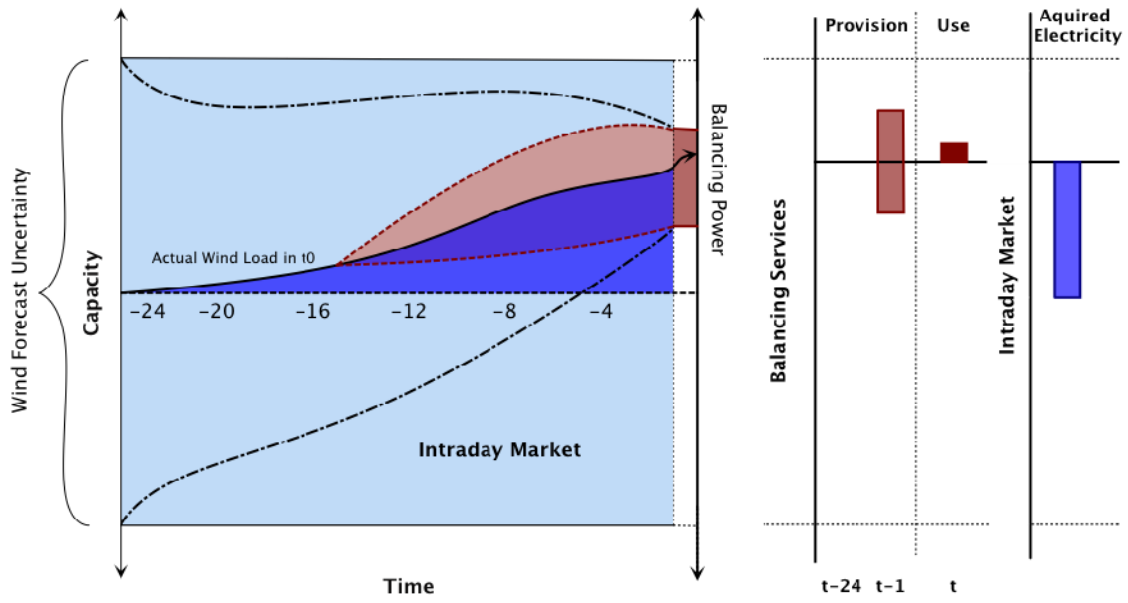

Figure 3-6: Joint optimisation of balancing capacities and intraday trading (EWI)

3.4.3 Joint provision of power across multiple hours

In general a system optimisation (efficient market outcome) occurs if generation companies can offer bids that combine offers for their production for individual hours. However, power stations require time and incur energy and other costs to be started up. As a result, generation companies cannot make decisions on the operation of the power station for individual hours, but have to consider interactions across hours instead. This allows for an efficient choice to operate a gas-peaking plant at short-demand peaks of one hour, and to start up other plants if demand is high for longer times.

Key issue with the current EU system: Inter-temporal optimisation of start-up and shut-down of power plants.

In systems with large hydro components, like in Scandinavia, start-up costs are of limited concern and inter-temporal optimisation is therefore of less relevance.

In other systems, market participants/market places have developed methods to submit a few specific block bids, e.g. to provide energy during day-time periods, or to submit

ramp-rate, start-up, and other constraints as part of their bid, as in U.S. ISO markets[27]. The system of specific block bidding has worked relatively well as long as it was possible to identify a block of hours for which demand will be higher. With increasing penetration of wind power, however, this situation will change, and the net demand (demand minus production of wind output) will not follow a strict pattern.

The EU needs systems that can reflect inter-temporal dependencies in the production of power in order to find efficient market outcomes[28]. Market designs across the US (PJM, NY-ISO, Texas, California) have evolved so as to allow generators to submit complex bids that reflect start-up costs and times, ramping constraints, and energy costs. Based on this information, the market clearing algorithm selects the most suitable set of power stations to provide energy and system services.

3.4.4 Capturing benefits from international integration of power systems

Larger regions reduce the overall demand for balancing and reduce costs for providing balancing power through a broader portfolio of power plants and additional sources for balancing power. However, larger regions also include more potential transmission constraints that need to be considered.

In some instances this might imply that at times when transmission lines are congested in one direction, no upward balancing services can be provided in this direction. At the same time, however, twice the volume of transmission capacity can be used to provide upward balancing services in the opposite direction (against the prevailing energy flow). This might be more valuable, because in a region with lots of wind output, only limited amounts of thermal generation capacity are operating and the region would therefore be in a position to provide balancing services and upward response capacity. In contrast, the importing country is likely to have more thermal capacity operating and

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27 Ockenfels et al. (2008) suggest that the pool type market models with their central organisation, might allow in particular the close co-ordination and synchronisation of generation, transmission, and balancing energy. They might be advantageous if competition is strong, they can be regulated effectively and the deficits of a centralised system optimisation, which always occur in practice, can be kept small.

28 Nabe (2006) points out, that for an efficient integration of wind energy, the short term markets must be able to cope and process more information especially with regard to inflexibility of conventional power plants. He proposes that: conventional power plants should be able to use bid arrays consisting of prices and technical information (ramp rates, minimum load, etc.) and Nabe (2006) points out, that such complex bids can only be processed by a centralised market mechanism.

is therefore potentially better suited to provide upward balancing services from this capacity.[29]

Key issue with the current EU system: Integration of congestion management with day-ahead and intraday energy and ancillary service markets

By using the potential to trade balancing and intraday electricity against the flow of transmission lines or reserve transmission capacities for intraday trading, the integration of congestion management and energy and ancillary service markets can enhance the value of the transmission network and reduce system operation costs. A complementary paper on congestion management discusses the value of an integrated energy and transmission market.

Current power market designs focus on an integration of energy and transmission markets at the day-ahead stage. As outlined in this paper, the intraday market is of equal importance, and the value of the flexibility provided by the transmission system increases closer to real time. Therefore a consistent approach is necessary that also facilitates integration of intraday energy and transmission markets[30]. The U.S. power market designs offer a possible solution. The market designs have succeeded in integrating energy, ancillary service, and balancing markets at day-ahead and intraday stages by using the same market-clearing algorithm for dispatch and transmission allocation for all markets.

3.4.5 Integration of demand side into intraday and balancing markets

Market liquidity can be increased if all market actors (not just conventional power plants) capable of providing intraday and balancing services can enter the market. Demand side management (DSM), and renewable energies especially, have the technical potential to provide their services to the market. At present, however, only a small share of demand side management is actually integrated into the markets. DSM technologies (such as reduction of electricity demand) face low costs for providing reserve

29 The effect is even stronger where the importing country is using the imported energy to store water, a process that can be easily interrupted with very short response times.

30 Newberry (2009) points out that the TSOs are subject to national regulation and therefore efficient cross-border transactions depend on the national regulation as well as the interplay between the various regulators involved.

capacities, especially for positive balancing power, and work well for circumstances where the probability that those reserve capacities will be used is low.[31]

Nordpool introduced a harmonization of balance regulation in 2009[32]. The new regulation lowered the bid size to 10 MWh to explicitly encourage demand side management The implementation of automatic activation for bids could further reduce the minimum bid size, (Von Roon and Wagner, 2009) thus providing greater incentives for non-conventional generation such as DSM to enter the market. Denmark introduced such a system in May 2008, and other Nordpool countries are following.

In 2007 in Germany, no DSM-potentials were prequalified and were thus unable to participate in the balancing market. An improved market design in 2008 allowed DSM technologies to provide balancing services in the minute reserve market. One aspect of the improved market design was the introduction of a day-ahead auctioning of minute reserve capacities and a reduction of the minimum capacities for prequalification to 15 MW. Energy intensive industries made use of their DSM-potentials and provided approximately 20% of the hourly demand for reserve capacities in the tertiary balancing market. In the secondary reserve market, technologies have to commit their balancing potentials on a monthly basis. DSM technologies, however, strongly depend on the downstream production process. A monthly pre-commitment cannot be met by most players with potential DSM technologies.

DENA (2010) shows that demand side management has the potential to provide reserve capacities for balancing power.[33] Demand side management might further provide load shifting from peak to off-peak and low-wind to high-wind periods.

Key issue with the current EU system: Incentives and access for demand side participants

Tight access rules still prevent large potentials of DSM from engaging in balancing and intraday markets. One pertinent criterion to market access is the lead-time and duration

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31 Therefore DSM-Potential corresponds to the left and right ends of the probability function in figure 1, while conventional power plants are ideal to serve the balancing demand close to the origin of the probability function.

32 See also Nordel (2008).

33 Today economic potential for demand side management stems from large industrial processes that serve as emergency capacities and are only rarely used. With decreasing costs for Smart-Meter and boxes and through bundling a large share of processes future DSM potential will become available in the tertiary sector starting from 2015 and later on in the household sector.

of a pre-commitment to the reserve and balancing markets. Only a day-ahead auction provides sufficient incentives for DSM and renewables to participate. In addition, a reasonable market design must be implemented that allows small units to engage in the market.

The US experience suggests that demand side investment follows once a market design is implemented that provides a long-term, credible framework and justifies the added cost of time and capital.

3.4.6 Monitoring of market power

The closer to real time that energy and balancing services are traded, the fewer the participants with the necessary technical flexibility and organizational capacity to participate in the market, which leads to greater market power for these participants and higher prices. With growing penetration of wind power, re-adjustments to the power system will be increasingly necessary during these hours close to real time and will amplify these circumstances of limited competition.

To avoid exposure to the very short-term market power of generators, system operators acquire a significant share of the balancing services in day-ahead and longer-term auctions. Multiple contracting rounds reduce, but do not eliminate, the ability of generators to exercise market power. However, this approach can preclude optimization across the provision of energy and balancing services and intraday adjustment.

In the mid-term, more power will be traded within the last 24 hours before delivery, and it will therefore become increasingly important to monitor the bids so as to control the exercise market power in these markets. The exercise of market power not only results in rent transfers to generators, but also distorts the price signal and thus creates inefficiencies that increase the cost of system operation and might provide misleading signals for investment choices.

Key issue with the current EU system related to monitoring market power: availability of transparent information, ability to evaluate bid price, and capacity to perform market power analysis

1. Availability of transparent information on bids and state of the system.

The identification of potential market power abuse requires access to information on bidding prices as well as a detailed record of the state of the power system.

2. Ability to evaluate whether bid prices are appropriate.

In energy-only markets that do not use the marginal bid to determine the market-clearing price (e.g. bilateral energy markets), market participants adjust their bid to reflect the scarcity value of generation. In this case it is difficult to differentiate between competitive and strategic bidding behaviour. Markets (e.g. current power exchanges) where the marginal bid determines the clearing price allow generators to submit bids at short-run cost, and are thus more suitable for market power monitoring.

However, generators that face inter-temporal constraints cannot offer power for only one hour and might therefore adjust their bids to reflect start-up costs and other constraints. Thus, it is difficult to assess whether the bid prices are competitive, which constrains the ability for effective market power monitoring. The approach in most U.S. markets, in contrast, allows generators to submit complex bids containing start-up costs and ramping constraints in addition to variable generation costs, such that all parameters can be assessed independently.

3. Institutional capacity to perform market power analysis

For an effective market power monitoring, an independent institution must have access to all relevant market information and must be equipped with the analytic capacity to provide an hour-by-hour analysis of the reserve and response markets. As the power system and many of the power generators are integrated across European countries, close cooperation or an integrated approach across Europe is necessary.

3.4.7 Summary of requirements for a future EU power market design

The EU power systems offer large technical flexibility, which allows for the use of improved forecasts to limit the impact of wind uncertainty. Table 3-2 summarises how the different power market designs currently implemented across Europe satisfy the criteria that emerge from this requirement. It also illustrates that the power market design that has become standard in the U.S. markets, such as PJM, offers the opportunity to satisfy all six criteria.

While long-term contracting remains bilateral, most day-ahead and intraday activity is pursued on the centralized platform of the independent system operator (ISO) and not bilaterally, as is the case in most European markets. This allows the system operator to calculate at close to real-time an optimal dispatch based on firm schedules submitted and flexible bids provided by market participants, incorporating various technical pa-

rameters, such as start-up costs and ramp-up times, allowing for inter-temporal optimization for all plants.

Table 3-2: Summary of power market designs performance against criteria

	Dispatch adjusted during day	**Balancing requirements/ provision adjusted during day**	**Flexible use of individual conventional power stations**	**International integration of intra-day/balancing markets**	**Integration of demand side response**	**Effective monitoring of market power possible**
UK system	Liquidity in bilateral market low, so utilities pursue internal balancing and hold excessive reserves	Difficult to find matching partners for trade	Only within portfolio of utility; difficult to find matching partner(s) that buy/provide energy matching demand/ technical constraints	Difficult due to separate energy and transmission markets; illiquid markets for both products intraday	No system-wide optimisation	Difficult because prices bundle energy, scarcity, and start-up cost
German system	To some extent, as TSO contracts energy intraday to match changing wind projections.	No, volume of balancing services contracted (not necessarily used) is pre-specified; also, generators cannot find matching partners to change unit-commitment	Only within portfolio of utility, difficult to find matching partner(s) that buy/provide energy matching demand/technical constraints	No	Possible	Difficult because prices bundle energy and start-up cost
Nordpool	Yes	Access to hydro power	Not necessary because of hydro flexibility, not possible because trade only hour-by-hour and pre-specified block-bids	Yes	Yes, provides a program to integrate DSM.	Difficult because prices bundle energy and start-up cost
Spanish system	Yes, intraday markets allow re-dispatch.	There is a day-ahead secondary reserve market after the closure of the day-ahead market and 6 additional markets between the intraday energy markets. Tertiary reserve is contracted in a continuous market.	Yes	No	Possible	Difficult because prices bundle energy and start-up cost
PJM type system	Yes, ISO can centrally coordinate intra-day adjustments	Yes, All markets are centrally coordinated. The ISO can decide if resources bid into the market are used to adapt to intraday changes or are used close to real-time.	Yes, Complex bids and a central optimization allow for inter temporal optimization of each power plant	Yes	Yes, PJM implements several DSM programmes to access potential on the demand side.	Yes, bids specify variable cost, start-up cost and technical constraints

3.5 Developments in the EU towards an integrated market design

This section explores the developments of the power market designs across the EU and the integration of these power markets in recent years. This raises the question of whether a continuation of the current process can deliver the improvements necessary to accommodate large scale wind and intermittent power station integration in Europe, or whether a more pro-active role at the EU level will be necessary to facilitate the shift to an effective power market design.

Recent developments in the EU power market

In 1999 the EU announced its objective of establishing a well-functioning, efficient, and open common market for electricity in Europe. The EU Directive 2003/54 provided a significant step towards achieving this objective by developing an outline for access to networks for the cross-border exchange of electricity. The initial focus was on improving linkage between Member States, primarily addressing the wholesale markets. In 2005 Meeus et al (2005) advised that a second stage of market integration was necessary where cross-border balancing (and intraday) markets should be implemented[34]. The sector inquiry in 2006 indicated that balancing markets were not yet sufficiently well designed, facing high market concentration, high prices, and missing European integration.

In an attempt to mitigate these issues, in 2006, national energy regulators launched a regional initiative to create seven regional markets, as a bottom-up attempt to provide a "practical and achievable way of delivering step-wise progress towards a competitive single European market for electricity." The regional initiative strived to harmonize the market design within each region and to foster the integration of the electricity markets. One measure used to link markets was to apply cross border market coupling, which replaced separate trading for energy and transmission rights between countries, instead using an internal market mechanism to optimize cross border trade.

The Nordic markets were the first to create a coupling of their markets. The Nordpool region implemented market coupling in day-ahead spot and balancing markets. In 2006 France, Belgium, and the Netherlands coupled their day-ahead spot markets. Germany and Denmark joined this day-ahead market-coupling scheme at the end of 2010.

34 NWEMPP et al. (2006) also address the importance of market coupling of intra-day and balancing markets.

The coupling of adjacent energy markets has provided significant improvements over day-ahead market results. Transmission lines are used more efficiently and the traded volumes follow the price differences between two regions. Such a market coupling mechanism can be applied to intraday markets and balancing markets as well. Smeers (2008) outlines that the so-called “flow-based market coupling” can provide a reliable platform for such market coupling and is, from a computational perspective, applicable for all markets from day-ahead to real-time, “provided one installs the adequate communication facilities to keep track of energy position and grid status”.

The measures of the regional initiative aim to address spot- as well as balancing- and intraday-markets. The status reports by ERGEG in 2008 and 2009 revealed that market coupling for balancing markets, however, existed only on a few selected interconnections. So far, market coupling of balancing markets has only been implemented within the Nordic market region and between Germany and the Nordic market region (Denmark). The 2008 report concluded that despite the improvements in the day-ahead market, market design or coupling of balancing markets still had low priority in certain countries. (See Table 3-3)

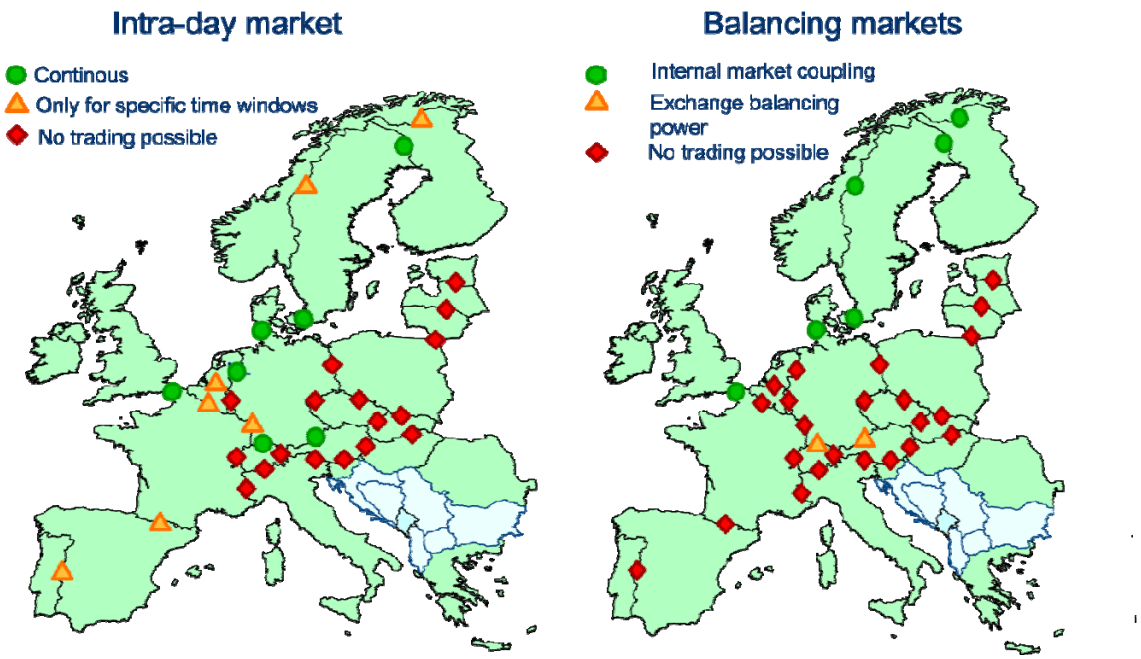

Figure 3-7: Cross border intraday and balancing markets trading arrangements in Europe in the beginning of 2009 (EWI)

First steps have been taken in recent years towards a common electricity market, however today's intraday and balancing market designs are still far from a fully efficient and harmonised market (Figure 3-7). The primary constraint to harmonisation of balancing markets is that these markets significantly differ in their market setup (Vandezande et al, 2009). Any approach to harmonising the markets must be able to overcome different gate closure times and to determine a balancing responsible party. The question remains whether the bottom-up approach is sufficient to reach the overall common energy market.

The EU Commission identified the need for a restructuring and harmonisation of the European electricity markets and implemented the third energy package that went into legislation in 2009. In five regulations the European Commission laid out the path for a European electricity regulating body and a harmonisation of the regulating authorities in Europe. The third energy package implements a European TSO (ENTSO-E) and aims to develop a strong and independent European regulatory body (Agency for the Cooperation of Energy Regulators) that complements the national energy regulators and fosters the harmonisation of the common energy market. This energy package departs from the bottom-up approach by implementing strong centralized structures that allow a top-down roll out of a harmonized market system. The EU regulation does not yet provide a clear vision how such a common market for spot, intraday, and balancing markets could be achieved and a binding process is still lacking at the EU-level to ensure harmonisation of rules for all markets (Eurelectric 2009).

Table 3-3: Congestion Management and Market Coupling: An Overview of the European approaches up to 2010[35]. Not represented in a regional initiative: Cyprus, Romania, Bulgaria, Malta and Switzerland

ERI-Region	Countries	Day-ahead		Intraday	Balancing
		Auction Rules	Market Coupling		
Cross-regional		Northern, CW and SW develop single set of auctioning rules		No consensus yet; different market designs; interference with balancing market; flow-based vs. ATC-based approach.	
Northern	Denmark Finland Germany Norway Poland Sweden	+ + + + + +	Market coupling between Norway, Finland, Sweden and Denmark (West) - Since 2009 market coupling between Germany and Denmark		Still some differences between Nordic countries, PL and DE
Baltic	Estonia Latvia Lithuania				Balancing model based on Nordic model to be developed
Central-West	Belgium France Germany Luxembourg Netherlands	+ + + + +	Full implementation of market coupling; price-coupling with SW	Bilateral solutions between DE-NL, NL-BE; ongoing public consultations	Low priority
Central-East	Austria Czech Rep Germany Hungary Poland Slovakia Slovenia				Low priority
Central-South	Austria France Germany Greece Italy Slovenia	+ + + + + +	Agreement on market coupling between Italy and Slovenia		Low priority
South-West	France Portugal Spain			Closed public consultations	Low priority: TSO-TSO model between ES and PT (MIBEL)
France-UK-Ireland	France Ireland UK			Explicit auctions	Full TSO-TSO model implemented between FR and UK

35 Primary source: ERGEG Status reports. ERGEG (2009)

3.5.1 Way forward

Apart from the question of what market designs have to be implemented, one of the key issues in 2010 is *how* to implement an improved power market design. To understand the viability of potential processes towards such a power market design, it is necessary to assess the interests of key stakeholders.

For a variety of reasons individual stakeholders might attempt to block, delay, or derail improvements to the power market design:

- Some existing generators might be concerned about an enhanced level of competition that might reduce lucrative margins in the intraday and balancing market.
- Some dominant incumbent generation companies might oppose a change to the market design that removes the benefit of internal balancing within the portfolio and thus removes barriers for the entry of third (competing) generators.
- If traders focus on short-term arbitrage across countries and intraday markets, then improved market design might eliminate all such arbitrage opportunities. Where traders do not have the skills to refocus their activities on longer-term and intra-fuel trading and hedging requirements for the power market (which are facilitated with more robust reference prices), they might oppose the change.

This raises the question of whether the potential opposition by these stakeholders might be compensated by support from stakeholders who benefit from an improved power market design:

- All consumers benefit from reduced system costs (operation, network investment), but constitute a dispersed group that is difficult to activate as they only incur small benefits individually.
- All consumers benefit from increased system security due to improved information exchange and from transparency that facilitates accountability. System operators with good operational procedures might appreciate this clarity, while badly managed TSOs are likely to oppose changes that create more transparency.
- Manufacturers of renewable technologies will benefit from an improved market design that creates flexibility for grid connection of new generation assets and thus avoids delays to the deployment of their products.
- Technology companies will benefit from a clear and transparent market design that offers a clear interface for new technologies for system control and demand side management.

A third group of actors, investors in renewable projects, still seems to be in the process of evaluating their position.

- Renewable energy producers are concerned that in the process of an improvement to the power market design, they will lose priority grid access. However, an im-

proved market design will provide the benefit of transparent dispatch choice that will prioritise generation technologies with low variable costs such as renewables.

- Renewable energy producers are concerned that market integration implies a shift away from a feed-in tariff with fixed off-take prices to facilitate low-cost financing. In fact, the improved market designs create a clear and transparent trading platform that allows the public counterparty to use feed-in tariffs and sell the output from renewable energy sources. Therefore an improved power market design facilitates the continued use of feed-in tariffs, combining the benefits of efficient system operation and low-cost financing.

There are potential opponents for market improvement within grid owners and generation companies. Given their strong role in domestic policy processes, often as dominant incumbents, it is likely that they will be able to block or derail bottom-up approaches to market design improvement where agreement of all parties is required.

The main winners are European consumers who will benefit from reduced costs, enhanced system security, and an enhanced likelihood of the delivery of renewable objectives. This points to the value of pursuing this initiative from a top-down perspective: e.g. with some form of leadership at the European level. Two options come to mind:

- A European framework specifying a harmonised design. The challenge will be to be sufficiently precise at the level of a European framework to ensure that the various regional implementations will be compatible with each other.
- A European sponsored/supported initiative for one subset of European countries. Nations can join from the beginning, but can also decide to join the initiative at a later stage. This approach is similar to the success of the U.S. American standard market design and the situation of PJM, which is gradually integrating neighbouring TSOs.

3.6 Conclusions

All long-term electricity scenarios show a large increase in installed wind capacities within Europe in the coming decades. Despite significant improvements in wind forecasting, the day-ahead forecasts will induce increasing uncertainty into the European electricity system. It will therefore be essential to make use of two factors: the improving wind forecasts within the hours between the day-ahead market and real-time dispatch, and the full flexibility that the generation, transmission, and demand side of the power system can offer to limit cost increases to deal with this (wind) uncertainty and to ensure full system security.

The power market design therefore has to satisfy six criteria:

- Facilitate system-wide intraday adjustments to respond to improving wind forecasts.
- Allow for the joint provision and adjustment of energy and balancing services.
- Manage the joint provision of power across multiple hours.
- Capture benefits from international integration of the power system.
- Integrate the demand side into intraday and balancing markets.
- Effectively monitor market power.

When comparing market designs based on these six criteria, it becomes apparent that none of the current power market designs applied across European countries fully meets all of them. In contrast, the power market design that has been initially used in PJM and by New York ISO and that has since been adopted in Texas and California does satisfy all six criteria listed in this paper. The assessment in the accompanying paper on congestion management suggests that the PJM type power market design (locational marginal pricing) also performs well with regard to the effective usage of transmission capacity.

Given the positive attributes of an alternative design, this raises the question of whether the current process of gradual EU power market design improvements can facilitate the implementation of such a design. The paper argues that more coordination and initiative at the EU level will be necessary to facilitate the effective operation of the common European markets. While some of the stakeholders might be reluctant to contribute to such a development, European consumers will benefit and EU Member States will be supported in their achievement of the renewable targets formulated in the EU renewable directive.

The third Energy Package provides opportunities to complement the bottom-up approach pursued so far on European power market design with top-down requirements. One cornerstone of the Energy package is the centralized organizational structure that is currently in place. As many market participants have disincentives to fully support a bottom-up transition to an integrated power market design, the provisions from the Energy Package might become essential in the European pursuit of a harmonized and effective power market design.

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4 Renewable Electric Energy Integration: Quantifying the Value of Design of Markets for International Transmission Capacity

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This paper has been produced in support of the “EU Intelligent Energy Europe program” which also funded part of the research. We would like to thank EU Intelligent Energy Europe program for providing the funding to support part of the analysis, ENTSO-E for the provision of the raw network data set. Friedrich Kunz acknowledges support of the RWE research fellowship (RWE Studienförderung). B.F. Hobbs was partially supported by the UK Engineering and Physical Sciences Research Council through the Supergen Flexnet Consortium (EP/E04011X/1), and by the US National Science Foundation (EFRI Grant 0835879).

4.1 Introduction

European energy targets are expected to foster an increase of some 200 GWs of renewable generation capacity by 2020. A main obstacle to large-scale renewable integration within Europe is insufficient network capacity and the congestion problems that will result, given that new generation will be required to share transmission capacity with the existing generation portfolio.

In addition, significant investment in network extensions will be required to adequately integrate increased renewable energy. Again, effective use of the existing network can reduce the need for network extension, can provide flexibility to more fully utilise the network, and can offer a transparent price signal to inform TSOs and regulators of the location of needed network expansion projects, and perhaps contribute to public acceptance of such projects.

Congestion represents the situation when technical constraints (e.g., thermal line limits, and voltage stability constraints) or economic restrictions (e.g., priority feed-in or contract enforcement limits) are binding and thus restrict power transmission between regions. Congestion management aims at obtaining a cost optimal power dispatch while

accounting for those constraints. The EU and some US states have adopted two contrasting approaches to address congestion in their market designs: the EU has opted for expansion on market coupling as proposed by ERGEG (2010), while five regional markets in the US have adopted locational marginal pricing (LMP), also called nodal pricing (O'Neill et al., 2005).

As zonal pricing does not capture the actual state of grid flows and congestion, it fails to provide information that is necessary to inform regulators, transmission operators and the public about the need for transmission reinforcement and investment. While other papers have discussed the relative benefits of nodal pricing compared to zonal pricing with market coupling,[36] the purpose of this paper is to quantify whether improving system design makes better use of the network capacities in the EU (UCTE, now called ENTSO-E).

To that end, we utilized an EU power market dataset (the UCTE-Study Model) and used three models for calculation: the ECOFYS model (Ecofys[37]) to calculate nodal prices; and the MADRID (Universidad Pontificia Comillas) and DRESDEN (Dresden University of Technology) models to calculate the differences between nodal pricing and zonal pricing resulting from the traditional Net Transfer Capacity (NTC) approach, which is defined in the Annex, where a detailed description of the models can also be found.

The results of the nodal system simulations using the DRESDEN and MADRID methods can be summarized as follows:

- Zonal-national boundary variations. The calculations show that under a nodal pricing structure, price zones do not conform to country borders and vary depending on the amount of wind output. The implication is that zonal pricing methodologies do not capture the physical reality of the grid; the zonal approach requires stable regions

36 Schweppe et al. (1988) and Hogan (1992) have shown that nodal prices lead to higher social welfare than zonal prices, let alone country-wide uniform prices. Other theoretical papers argue that a system using nodal pricing accommodates renewable energy sources more efficiently and can provide increased stability to the system. The TradeWind (2009) and EWIS (2009) studies discussed system needs for large-scale wind integration, but did not compare net transfer capacity (NTC) and nodal pricing regimes. Leuthold et al. (2008) have shown the superiority of nodal pricing for the integration of wind into the German network. Other estimates of cost savings from using full network models and nodal pricing rather than zonal pricing and aggregate intercountry transfer capacity are provided by Barth et al. (2009) and van der Weijde and Hobbs (2011). See the discussion of the literature in Section 4.1.

37 The Ecofys model is an OPF model based on the MATPOWER simulation package (MAT09, 2009).

with homogenous price levels and thus creates considerable redispatch costs and gaming opportunities.

- Congestion dynamics under varying wind scenarios. The variation in distribution of congestion under different wind scenarios suggests that zones have to be very small if congestion within zones is to be limited, illustrating the need for nodal pricing.

To determine the difference between a nodal pricing regime and the current EU system, the simulated nodal results were then compared to a second set of simulations representing implicit auctions with joint allocation of transmission capacity (NTC) across all international links, i.e., the optimization of the current paradigm pursued by European Regulators (ERGEG, 2010). For this purpose, the models first calculated the volume of total transmission capacity (TTC) based on the calculation methodology presented in ENTSO-E documents and reported by TSOs in interviews that were undertaken as part of this research. This provided TTC values that were consistent with the model network and were used as a base for the simulation of market results (using the MADRID and DRESDEN methods) from the day-ahead market with subsequent redispatch where necessary. We then evaluated the differences between the nodal and zonal approaches as determined in the models. The main conclusions of this comparison are as follows:

- International transfers. The nodal pricing approach leads to an increase of up to 34% in international MW transfers between countries, depending on wind power penetration. This means that the existing network capacity can adequately accommodate increasingly large volumes of intermittent energy sources. The sum of all cross-border transfers reaches 43 GW at maximum wind output, in both the Dresden and Madrid models.
- Cost savings. Annual savings of system variable (mainly fuel) costs under a nodal pricing structure range from €0.8 - €2.0 billion depending on the penetration of wind power. This is represents an average of 1.1% - 3.6% of operational costs can be saved. These results are in line with empirical values from the USA and the results of a simulation model for a small-scale network. These do not include possible savings in unit commitment costs such as start-up and minimum run costs, which were not calculated.
- Country level marginal prices. Weighted marginal prices are lower under a nodal pricing regime in 60% to 75% of EU countries. Real-time congestion mitigation measures such as wind spilling, load shedding and power plant re-dispatching are relatively costly options, the uses of which are minimized under a nodal approach.

The paper is organized as follows. In Section 4.2 we look at the issues related to congestion management in an environment of increased renewable energy: this includes a survey of literature and previous studies. Section 4.3 provides a summary of the data used and the simulation results, with a discussion following in Section 4.4, including a

comparison with other studies. Section 4.5 presents conclusions. The Annex describes existing methodologies for calculating international transfer capacities, and then introduces the nodal pricing and the NTC-constrained dispatch models that we have developed for this paper.

4.2 Survey of Issues: Review of Solutions to Congestion Management

4.2.1 Studies on Congestion Management Mechanisms

Congestion management is a key element of market design. The main issues are how transmission capacity is allocated in times of shortages, and methods for coping with congestion efficiently.

In general, congestion management mechanisms can be classified into transmission capacity allocation and congestion alleviation methods (Androcec and Wangensteen, 2006; Brunekreeft, et al., 2005):

- Transmission capacity allocation methods aim to optimally allocate existing capacity among potential users. The methods can be grouped into either explicit auctions (first come, first served; pro-rata rationing; explicit auctions), or implicit auctions (bilateral implicit auctions; market splitting, market coupling, nodal pricing). Furthermore, a differentiation can be made according to the way that physical power flows are taken into account: non-flow-based methods assume that electricity can be transported between specific locations in the grid without violating physical constraints whereas flow-based methods respect the grid's actual physical constraints. Figure 1 provides an overview of these congestion management mechanisms.
- Congestion alleviation methods aim to manage existing or expected congestion using re-dispatching of power plants and counter trading.

In fact, many power market designs combine approaches to avoid the need to alleviate congestion, e.g., by defining capacity available for international commercial transactions so that congestion within countries is eased.

In Europe, solutions to relieve cross-border and inner-country congestion focus on coordinated market coupling or splitting (Ehrenmann and Smeers, 2005). Market coupling assumes that sub-markets already exist and cannot be merged into one integrated market in the short- or medium-term. If there is no congestion, the prices in the sub-markets are set equal; otherwise, the prices can separate. Market splitting assumes an existing integrated market where injections and withdrawals of several nodes are assigned to a specific zone in case of congestion. A third approach, coordinated explicit

auctions, also attempts to interlink different markets. In this case transmission capacity and energy is traded on separate markets.

A well-known engineering solution to congestion management is to use an Optimal Power Flow (OPF) optimization tool (Wood and Wollenberg, 1996) which optimally, i.e., at minimum cost, redispatches generators in a network to relieve congestion. OPF has been widely used since the late 1960s, well before the advent of liberalization, by vertically integrated utilities which were able to control directly the generators they owned. A realization by Schweppe et al. (1988) that so-called Lagrange multipliers, which are a by-product of OPF, have an economic interpretation of nodal shadow prices was a break-through that made it possible to introduce market-based power system operation. The shadow prices (often referred to as the Locational Marginal Prices or LMPs) reflect the marginal cost of increasing generation or demand at any node in a secure way, i.e., without violating any transmission constraint included in the model. It can be proven under mild conditions that generators facing the nodal prices would maximize their profit by generating the level required by OPF (assuming price-taking or competitive behaviour). Economists refer to such prices as 'equilibrium supporting prices' (O'Neill et al., 2005). In other words, market-based prices achieve the same goal of congestion management as the direct command of generation by traditional vertically-integrated utilities. This way the prices are compatible with, and are an integrated part of, optimal and secure power system operation.

It is important to emphasize that practically all utilities, including the vertically integrated ones, use OPF as an engineering tool to manage congestion. As LMPs are a by-product of OPF, they are readily available for use to settle spot power markets.

"Security-constrained, economic dispatch with locational marginal pricing" (Hogan, 1992) is now used by many restructured electricity markets, such as Australia, New Zealand and Chile. In the US, five restructured markets have adopted locational marginal pricing: PJM-MISO, New England ISO, New York ISO, ERCOT (Texas), and the Californian ISO (O'Neill et al., 2008). The US experience illustrates that small variations in the formulation of the optimization model that clears the market and subsequent calculation of settlements can change the amounts paid by individual generators and groups of consumers and can lead to disputes. Just a few examples of auction and settlement design choices include: whether start-up costs are repaid if otherwise generators would lose money under the energy prices they are paid; whether such start-up payments are recovered from consumers by adding them to peak prices or spreading over all energy sales; and whether domestic consumers are exposed to nodal prices or an average regional price. Up-front consideration of these specific market design deci-

sions, and consistent application of the chosen design across European countries, can facilitate implementation and integration of power markets.

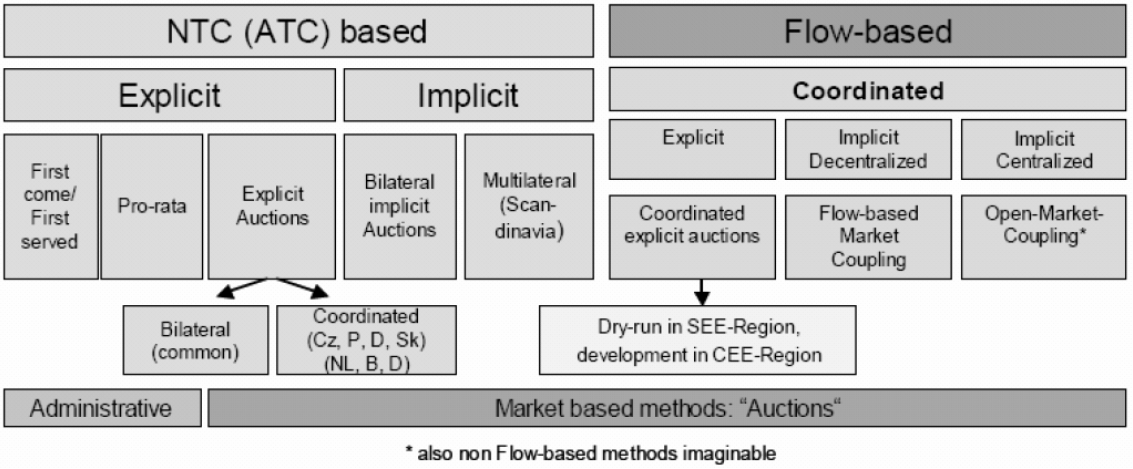


Figure 4-1: Evolution of CM mechanisms. Source: Vujasinovic et al. (2005, p.3), Leuthold (2006, p.6), ETSO (2007, p.6)

4.2.2 Security Issues

Power system security has always been the main focus of grid operators in their daily operation. The two most important facets of power system operation affecting security are the following:

- The lack of significant storage capacity requires short-term management of the generation/demand balance.
- In a meshed transmission network, such as the one discussed here, power flow along a line is the outcome of the overall pattern of generation and demand in the whole system. For instance, the overall system generation/demand pattern has to be changed if any of the transmission lines are overloaded – this adjustment is referred to as re-dispatch.

Many examples illustrate the importance of the integrated approach to power system operation. Although the large-area power system blackouts in 2003 (US/Canada, Italy) and the so-called UCTE disturbance in 2006 were caused by rare events, the reason they affected such large areas was the insufficient coordination of operation between the TSOs involved (Bialek, 2005, 2007). Direct economic losses caused by the blackouts were in the range of billions of Euros.

The original reason for interconnecting individual control areas or countries was to minimize the requirement for a back-up generation reserve should any generator trip, and to provide better frequency response. The required whole system reserve is much smaller than the sum of individual reserves if each control area was to operate separately. Frequency variations also tend to be much smaller in a bigger system due to a higher overall inertia of generators. Prior to liberalisation, the capacity of interconnecting tie-lines tended to be limited as they were necessary only for back-up purposes or for limited and controlled cross-border trades. That situation changed in the 1990s with liberalisation of the electricity supply systems in Europe and elsewhere. The tie-lines have been increasingly utilized, facilitating an explosion in cross-border trades. This has resulted in a significant congestion in Europe: 12 out of 24 interconnectors in Europe are permanently or frequently congested, 5 are occasionally congested and only 7 seldom or never congested (EC, 2003). On top of that there is also congestion in internal networks within each country.

The level of congestion will increase as investment in renewable power generation is pursued to deliver the 20% renewable energy target by 2020, which implies significantly higher shares of renewable electricity. Renewable generation is generally highly intermittent – the average load factor of on-shore wind farms is about 20-30%, while the load factor of off-shore wind farms tends to approach 40%. Consequently it is not economically sensible to upgrade the transmission networks to handle the full capacity of wind farms as the networks would be rarely fully utilized. This means that at times of high wind, transmission networks are likely to exhibit more severe congestion, and therefore efficient sharing to facilitate least cost generation to meet demand will become more important.

4.2.3 Studies Focusing on Wind Integration: TradeWind and EWIS

Two comprehensive studies have been carried out recently on the impact of wind on European network development: the TradeWind study (TradeWind, 2009), which is an Intelligent Energy Europe (IEE) project led by the European Wind Energy Association (EWEA), and the European Wind Integration Study (EWIS, 2010), which was a joint project between European TSOs, co-funded by the European Commission. The EWIS study focuses on short term actions for network development with emphasis on the expected situation in 2015 and an outlook to 2020, whereas the TradeWind study simulates the integration of wind scenarios until 2030.

While the wind scenarios in both studies are very similar, the studies differ with regard to the methodological approaches and the underlying datasets: the EWIS study exam-

ined a small set of robust Point-in-Time situations to evaluate European-wide coordinated measures in great detail based on the "UCTE reference data set" from the participating TSOs.[38] In contrast, the TradeWind study had to rely on a simplified UCTE network model (with network areas defined mostly on country basis), which is available in the public domain (Zhou, 2005). The EWIS study was able to perform a detailed analysis, e.g., of voltage problems and internal congestion, but was not able to quantify the importance of these problems, for instance in terms of number of critical hours of a year. On the other hand, the annual chronological production simulation performed in TradeWind shows the frequency of overload situations.

Based on a cost-minimizing dispatch, the impact of market design and transfer capacities between countries could be analysed by these studies, providing several useful insights:

- The EWIS study suggested that internal congestion was significant in the examined snapshot simulations.
- A temporary curtailment of wind could avoid line overloading and lead to an overall cost reduction.
- The TradeWind study identified 42 onshore interconnectors and a corresponding time schedule for upgrading that would benefit the European power system and its ability to integrate wind power. Reinforcing these lines should lead to substantial cost savings in total system operation costs of €1,500 million/year for 2020 and 2030. In those years, congestion can be expected to increase on the borders of France, between the UK and Ireland and on some of the Swedish, German and Greek borders. An interlinked (meshed) offshore grid could link future offshore wind farms in the North Sea and the Baltic Sea and the onshore transmission grid.
- TradeWind's preliminary economic analysis based on an installed wind power capacity of 125 GW shows that this system compares favourably to a radial connection solution where wind plants are only connected directly to the onshore grid. Allowing for intraday rescheduling of cross-border exchange will lead to savings in operational costs in the order of € 1-2 billion per year compared to a situation where cross-border exchange must be scheduled day ahead (TradeWind, 2009). This suggests that interconnector capacities should be allocated directly via implicit auction.

38 This dataset contains the full network information and is also used for the day-ahead congestion forecasts. Its level of detail allows performance of N-1 security analysis and the evaluation of voltage profiles.

While the existing simulation studies for the European grid have assessed the value of transmission capacity, and the implications of explicit versus implicit auctions as means to grant access to international interconnectors, this study now also assesses the implications of congestion within countries and how they impact on the choice of market design.

4.3 Data and Results

4.3.1 Methodologies for Calculating International Transfers

Before we turn our attention to calculating the efficiency of various models for international capacity allocation (a key component of congestion management), the processes and definitions relevant for international capacity allocation are outlined in the Annex, in which also lies the technical description of the models used. Of particular relevance to this section, however, is the concept of Net Transfer Capacity: the maximum possible transfer between two systems without violating security requirements. Maximising NTC maximises international capacity allocation. International capacity allocations distinguish between commercial transfer limits (which are used by market participants to plan their cross-border trades), and physical values (as used by system operators in real-time operation (ETSO, 2001a)).

4.3.2 Case Study Data

We use the UCTE-Study Model (UCTE-STUM) dataset, which was provided by ENTSO-E for research purposes. The UCTE-STUM is a limited version of the UCTE reference data set for each seasonal period produced for third-party analysis.

The dataset comprises a forecast for the static operation of the UCTE control area for the 3rd Wednesdays in January for the year 2008 and includes a detailed representation of the former UCTE network of approximately 4,300 buses, 6,300 lines and 1,100 transformers together with their loads and generation in-feeds. The dataset allows the calculation of the AC load flow for the respective snapshot of the system operation. Being a tool dedicated to perform AC power flow calculations, the UCTE-STUM dataset has important limitations:

- The model does not contain geographic (latitude-longitude) information on the network nodes,
- Transmission lines have been aggregated to equivalents, especially parallel circuits and medium voltage distribution networks,
- Transmission capacities are partly missing or are in some cases implausible,

- Information on generator characteristics are not provided, and
- Loads and distributed generation have been aggregated for each node.

To perform network studies, the UCTE-STUM dataset was enhanced to allow dispatch optimization. Specific actions were undertaken to address the above data limitations.

The geographic locations of nodes were identified in a manual process based on the public ENTSO-E network map, using the abbreviations provided by the UCTE-STUM dataset. In Figure 4-2, the result of this mapping is presented, where different line colours are used for the different voltage levels and equivalent elements are represented with dotted lines.

A European generation database was matched to the nodes including power plants with capacities exceeding 100 MW. The matching was performed on the basis of geographic proximity and according to information provided at the public ENTSO-E network map. The total installed capacity amounts of approximately 430 GW, comprising 10 generation technologies, is presented in Figure 4-3. To counterbalance the impact of distributed generation, nodal loads were increased pro-rata on a country basis, based on the load values published on the ENTSO-E website. The derived total system load for the obtained snapshot amounts to approximately 300 GW.

Wind feed-in scenarios were calculated and matched to the network nodes based on the “high scenario 2008” of the TradeWind study (TradeWind 2009, pp. 21). Beside a scenario without wind production, three wind production snapshots (high: 38 GW, medium: 13 GW and low: 1 GW) were selected as representative scenarios of the total wind feed-in in the system corresponding to a total installed wind capacity of approximately 63 GW. The derivation of these snapshots from the aggregate wind power distribution is presented in Figure 4-4. Transmission lines were de-rated to 80% of their nominal capacity to approximate the N-1 security constraints in the network. Finally, transmission lines with unrealistic or missing capacity values were adjusted to realistic values.

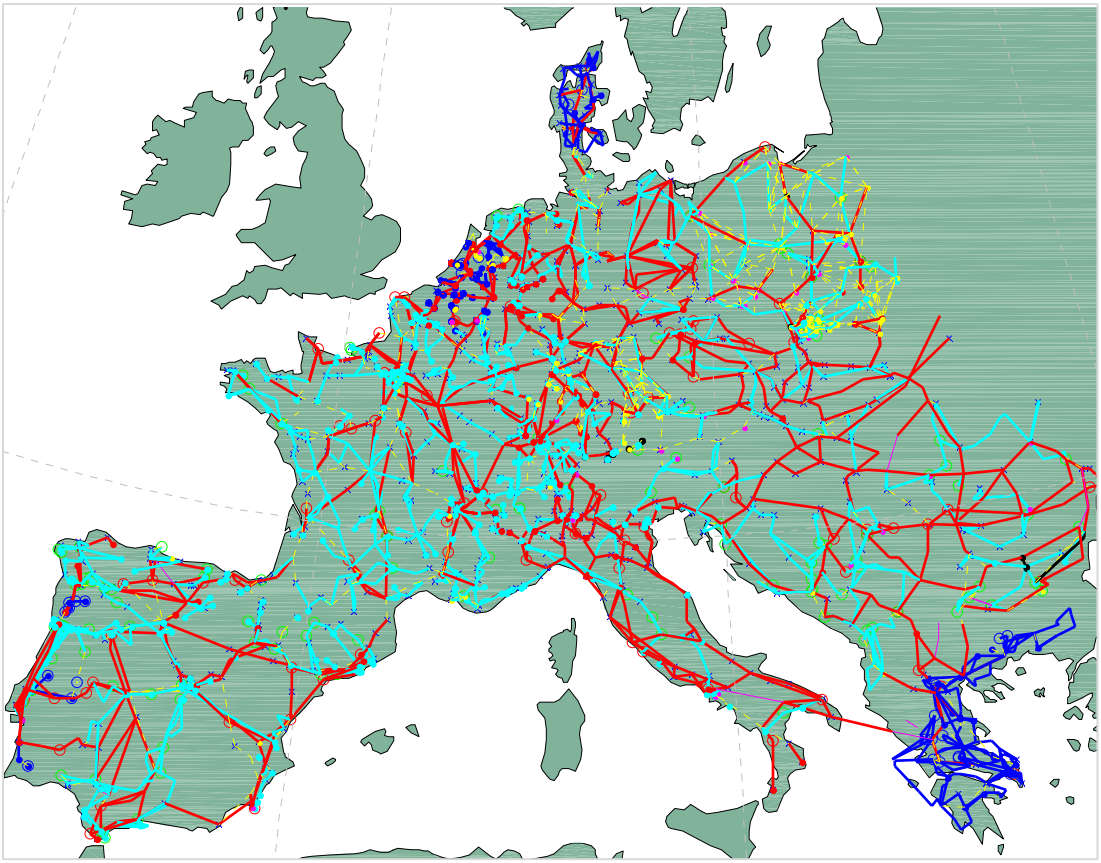


Figure 4-2: Network model geographic representation. Different line colours represent different voltage levels (red: 380kV, cyan: 220kV, blue: 150kV) and dotted lines correspond to equivalent

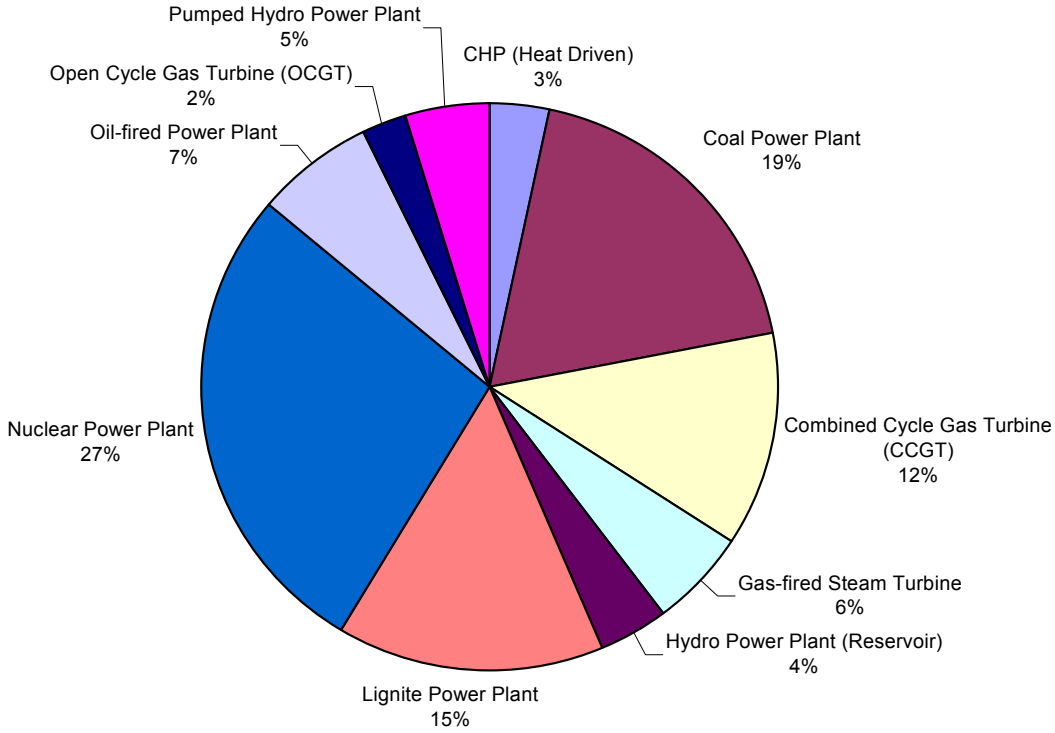


Figure 4-3: Generation technologies mix used in the models

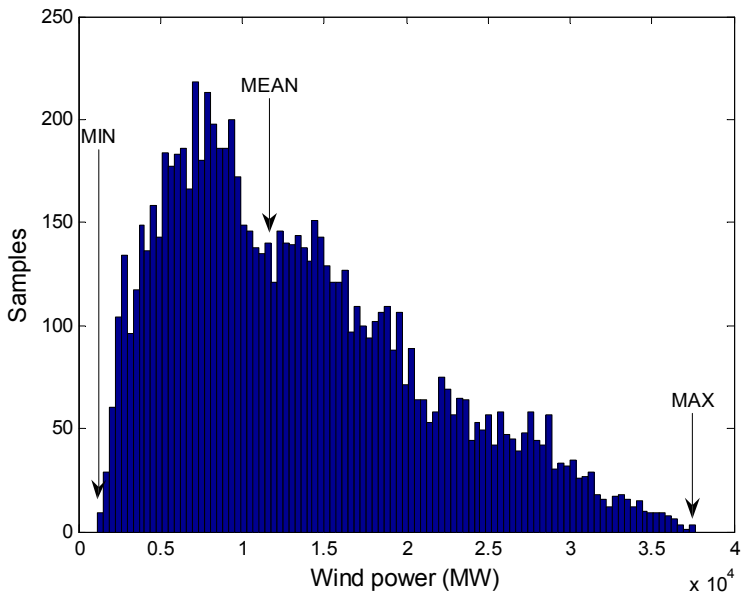


Figure 4-4: Distribution of the aggregate wind in-feed for the 2008 (H) TradeWind scenario and the respective snapshots.

4.3.3 Comparing nodal pricing simulation results

We start by comparing the results from the DRESDEN and MADRID models to simulate nodal prices under different wind penetration scenarios across the observed region. In Section 4.3.4, we will simulate implicit allocation of transmission capacity across Europe. Subsequently, we compare the two sets of simulations in Section 4.3.5 to derive conclusions concerning the effect of nodal pricing on system costs and network utilization. We also evaluate the price levels resulting from the models, comparing them as well to actually observed prices in the current EU system.

Figure 4-5 (DRESDEN & MADRID) depicts the volume weighted nodal price by country as an indicator of the prices that would be experienced under nodal pricing (and ultimately added to transmission, distribution, and administrative costs and then passed on to final consumers). The estimated price level in Madrid is lower – because all units are operating – while the Dresden model includes a unit commitment algorithm, which results in less capacity on line and higher marginal costs. However, the Dresden solution has lower total costs than the Madrid solution if all commitment (start-up and minimum load) costs are considered.

For the countries in Figure 4-5, data on day-ahead market prices was available for comparison, indicated by bars. A range of priced products are available and offer some insights for the hour of the reference case (10 a.m.-11 a.m., Wed. 16-Jan-2008). The day-ahead spot price for that hour is closest to the specific situation of network and generation assets, but additional factors (contract positions, intraday changes to dispatch) might have impacted the price or network configuration. Hence, we also depict the average price for this hour across all Wednesdays in the month to abstract from specific aspects of the day, and the peak price in the day-ahead market to abstract from specific aspects inherent in the hour. The overall price levels are similar between simulated and observed prices, with the largest discrepancy occurring in Austria. This can be attributed to the complex congestion structure combined with the impact of international flow patterns in Austria (see Figure 4-8).[39]

39 We also confirmed that flow patterns observed in the simulation corresponded to the expectations of the participating power system experts from Spain, Germany and UK. When interpreting the data, it is important to account for the approximations used in the parameterization of individual lines that were not already characterized in the ENTSO-E data set. Furthermore, the future siting of wind turbines is likely to differ from the projections used in the model. Hence the model results do not provide an accurate representation of future congestion of specific lines, but can only capture the general structure of congestion in the network.

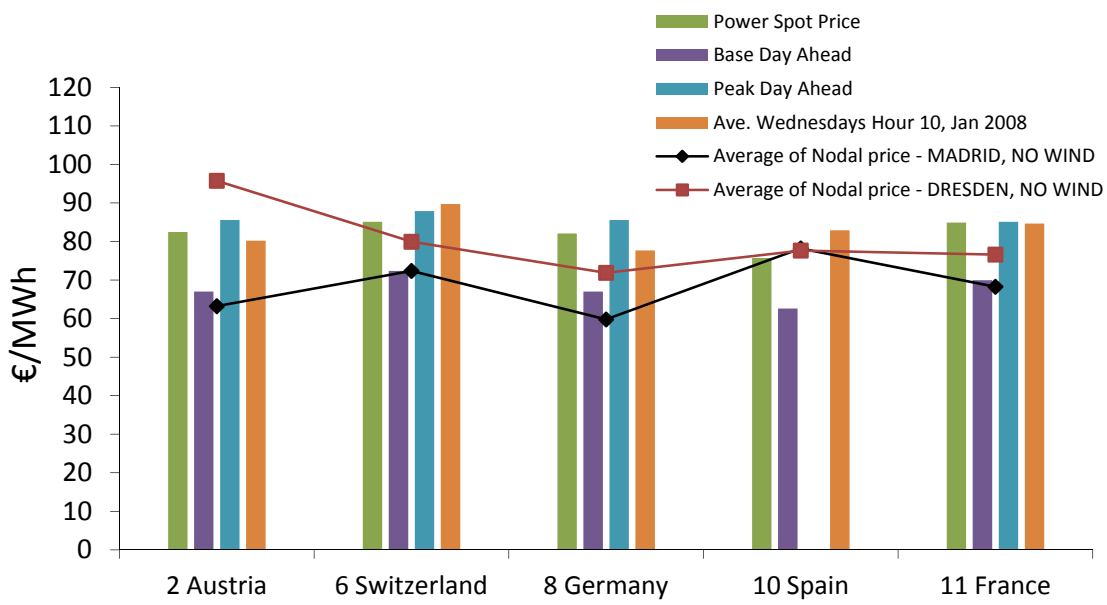


Figure 4-5: Comparison of selected actual market prices for power products for Wednesday 16 January 2008 (bars) and simulated prices (DRESDEN, MADRID).

Figure 4-6 depicts the distribution of the loadings of all the system branches for the max wind scenario. About 50 out of about 6,000 branches are loaded up to their limit, the majority of which correspond to branches within zones (internal congestions). In particular, only 2 branches are cross-border lines while 6 are HV transformers[40]. In Figure 4-7, the line loadings for the European network for the respective scenario are presented, where the geographic extent of congestion can be seen.

In Figure 4-8, the nodal price distribution within Europe for two operational snapshots, the no wind case and the maximum wind case, are presented. The calculations show the existence of uniform price areas in Europe that do not necessarily match the national borders. The impact of wind integration in Northern and South West Europe can be seen by the reduction in nodal prices. Different price zones indicate congestion, either across borders (e.g., between France and Italy) or internally (e.g., North – South Germany).

40 As will be discussed later in the section, international flows in the NTC modelling case decrease by 14% - 34% relative to the nodal pricing case. This suggests that in the current NTC-based power market design, the number of physically constrained lines between countries is lower than simulated here.

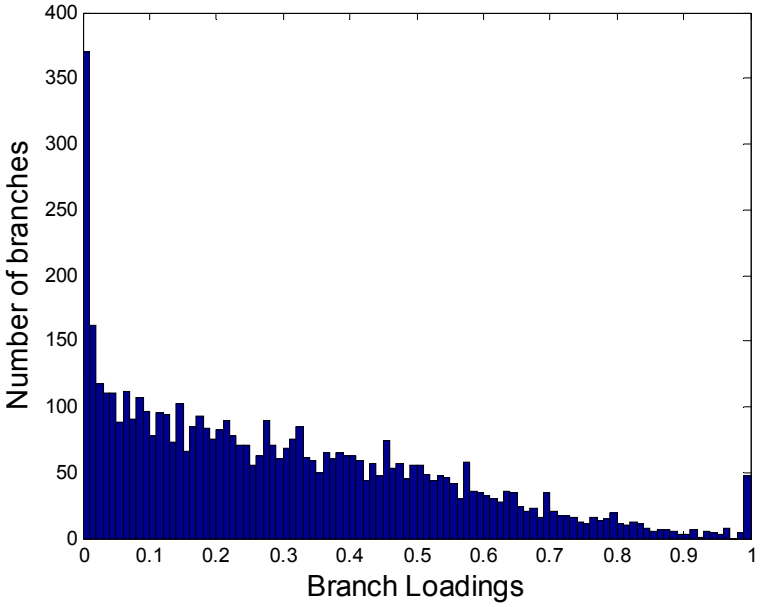


Figure 4-6: Distribution of branch loads (as a fraction of capacity) for the analysed high wind scenario

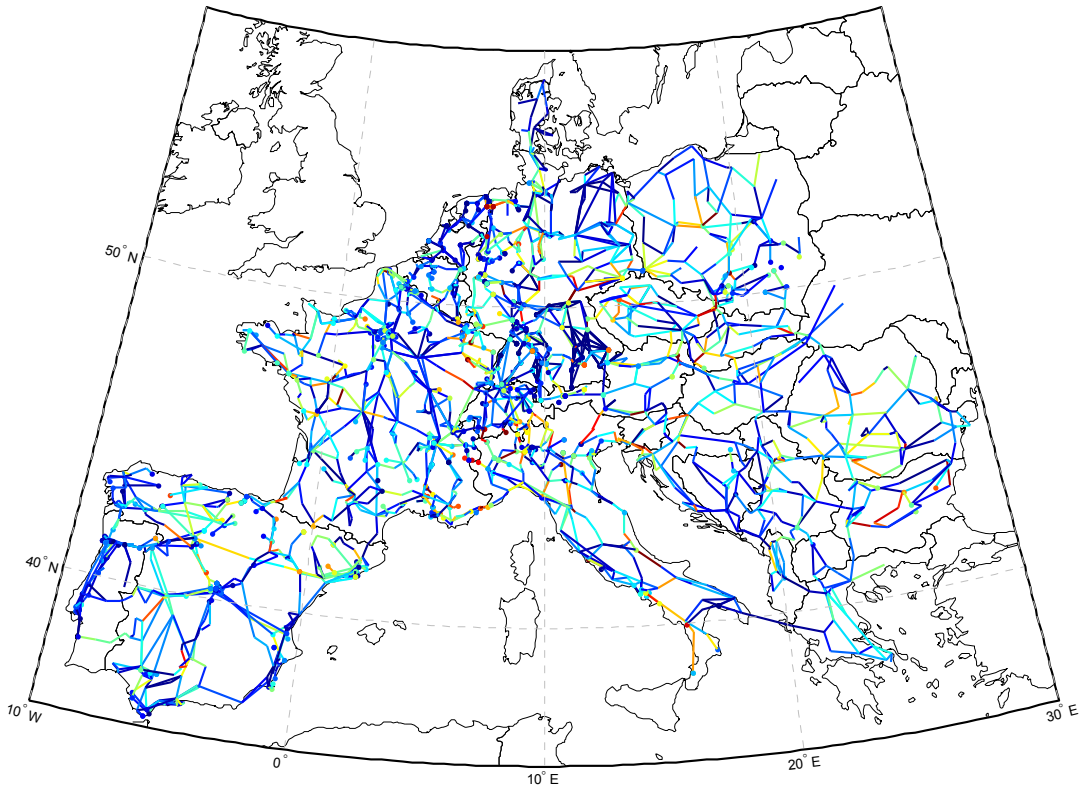


Figure 4-7: Line loading representation for the maximum wind scenario. In this representation, the line loading is depicted with a respective colour: from blue colour (not loaded) to red (congested lines).

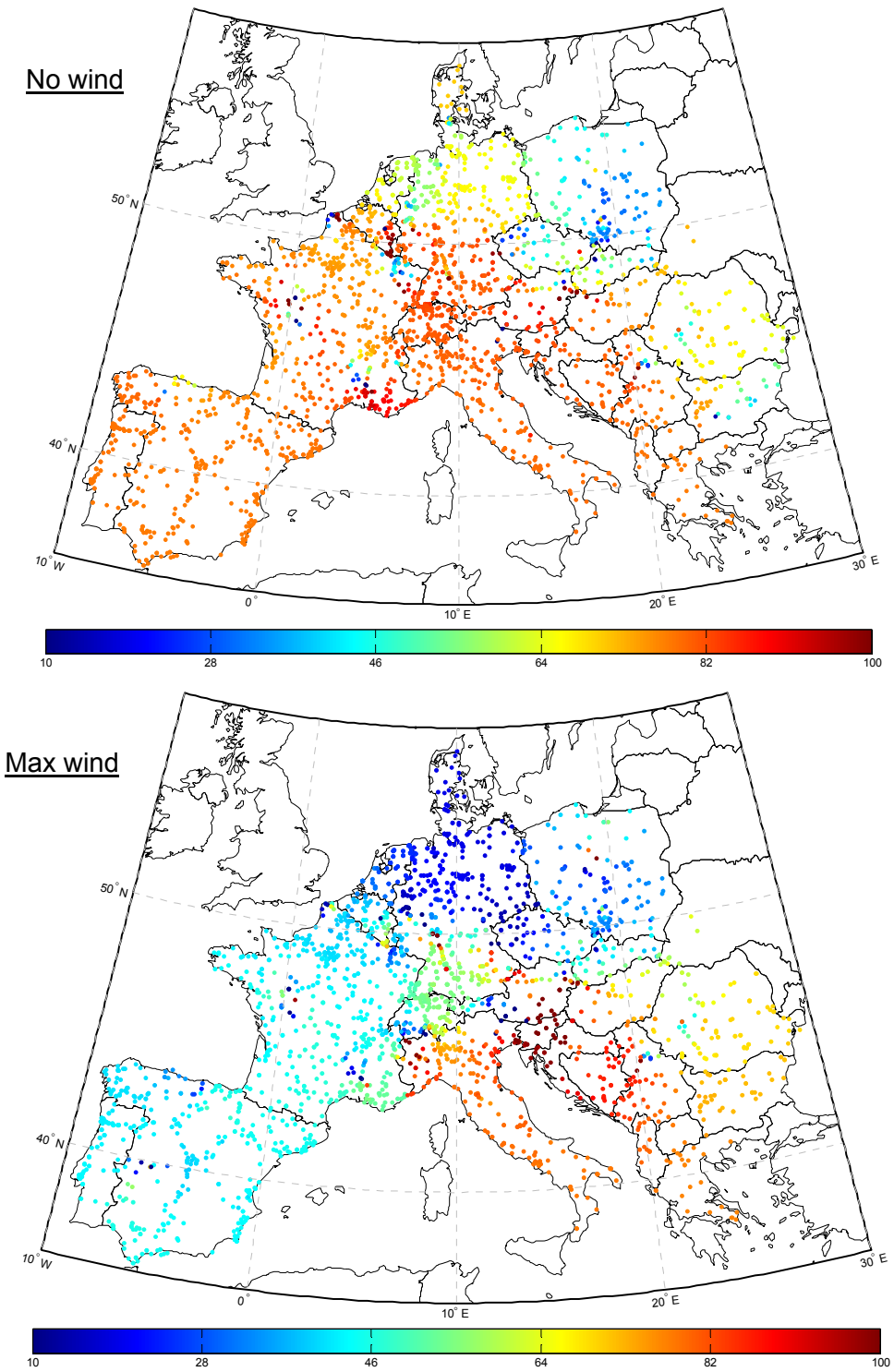


Figure 4-8: Geographic representation of nodal marginal prices. Bar represents energy prices at nodal level: from €10/MWh in blue to €100/MWh in red. (NO WIND scenario above, MAX below).

4.3.4 Simulating implicit allocation of transmission capacity across Europe

Based on the parameterization of the network representation, and after confirming that simulated nodal prices from the models provide consistent results, we then undertake the main task of the modelling exercise: the DRESDEN and MADRID models are used to calculate the TTC values for available transmission capacity between countries. Using these estimated TTC values in a TTC-constrained simulation then allows a consistent comparison with model runs under the nodal pricing regime (Section 4.3.3). As described in Annex A.1, the NTC (published by ENTSO-E) is calculated by the difference between TTC and TRM. The TRM is however not available for all transmission lines, thus preventing a direct comparison of modelled values and values actually announced by the TSOs.

Next, both models simulate implicit auctions allocating transmission capacity (TTCs) between European countries. The DRESDEN model undertakes a two stage approach: first, initial trading is carried out among generators and demand, respecting international transmission constraints as defined by the TTC values, but not transmission constraints within countries. This trading is based on a transhipment (path-based) model. Second, national TSOs then resolve congestion on lines within their respective country by redispatching national generation while keeping international net MW transfers fixed (i.e., no international redispatch). This likely yields higher operating costs than the DRESDEN nodal model (and certainly no lower costs) because the nodal model does not impose the NTC constraint, and only imposes the line constraints without restricting the international transfers to possibly suboptimal values found in the first NTC run. Meanwhile, the MADRID model simultaneously imposes the international transmission constraints (TTC values) and all line constraints, thus directly obtaining a feasible solution but underestimating the potential redispatch costs. Because this is the same as the nodal pricing simulation, except for the additional TTC constraints, the cost of the TTC run is necessarily no lower (and in all likelihood higher) than the nodal run.

Figure 4-9 provides the DRESDEN simulation's price results – volume weighted across EU countries – for different wind scenarios. The dashed line gives the market results from the first stage (roughly corresponding to day-ahead market). The national TSO(s) then independently pursue national redispatch to ensure the flow patterns do not violate national transmission constraints while keeping international flow patterns constant. The final energy prices thus comprise the energy prices as calculated in the first stage with an additional amount to cover redispatch costs.

Two options to translate the redispatch into redispatch costs are depicted by the grey area. For the lower end of the area it is assumed that each country's TSO can price discriminate among its nodes when redispatching, and thus limit re-dispatch costs. The upper end of the range assumes that all upward response (constrained-on production) is paid the maximum price within the country, and similarly all downward responses (constrained-off production) pays the lowest price for such buy-back within the country. Again, the TSO's net expenditures on redispatch are recovered by increasing the zonal prices. Typically the TSO has to pay the market price rather than remunerating generators at cost. The upper end of the range thus corresponds to a competitive market outcome. With market power, where generators submit bids that diverge from their variable cost, the prices could further increase. In fact, if generators anticipate payments that are available in the redispatch market, then they are likely to bid in this manner, raising prices above those depicted in the figure.

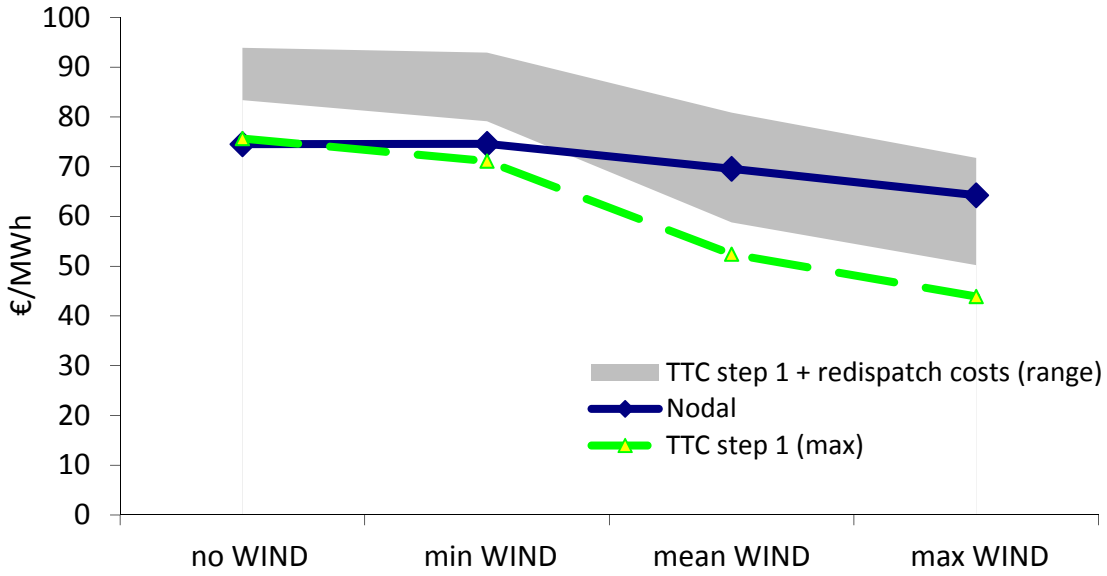


Figure 4-9: EU-wide volume weighted prices from DRESDEN model. [41]

Figure 4-9 shows that volume weighted power prices for the day-ahead market (assuming no interaction with intraday redispatch and no strategic behaviour) are more responsive to higher wind deployment than nodal prices. The reason is that zonal pric-

41 Due to data constraints, generation and demand in Portugal and Ukraine is assumed to be fixed. Hence, these countries are not considered in the calculation of EU-wide average prices.

ing disregards the internal transmission constraints in the TTC structure. High wind output is free to replace – in the day ahead market at least – the most expensive generation assets without being constrained by within-country transmission limits, and reduces the market clearing price in the first stage (day-ahead market).

In contrast, in the nodal market, internal constraints can prevent all of the wind output from being used. Respecting the internal transmission constraints can mean, for example, that high wind output in Germany can replace some of the coal power production in Northern Germany, but cannot replace the more expensive gas power stations in Southern Germany due to North-South transmission constraints. As a result the volume weighted nodal price can remain higher than the day ahead price (excluding redispatch cost) in the TTC case.

In practice, regional prices in an NTC type approach will increase in the day-ahead market as well for the following reason. As the likelihood for redispatch increases, generators in load pockets anticipate the possible revenues in the redispatch mechanism and have incentives to increase their bids in the day-ahead market so as to not be chosen for the lower price market. Generators might even choose to bid strategically in the day-ahead market so as to increase the need for redispatch and costs for consumers. This strategic behaviour is known as the increase-decrease 'inc-dec' game that destroyed the PJM market when it attempted to implement something similar to zonal pricing prior to moving to nodal pricing (Hogan, 1999), and was a main contributor to the failure of the California power market in 2000-2001.

4.3.5 Simulation results comparison for system costs and network utilisation

We now compare the volume of international transfers and cost savings of the TTC and nodal flow using both the Dresden and Madrid models.

International Transfers/Network Utilization

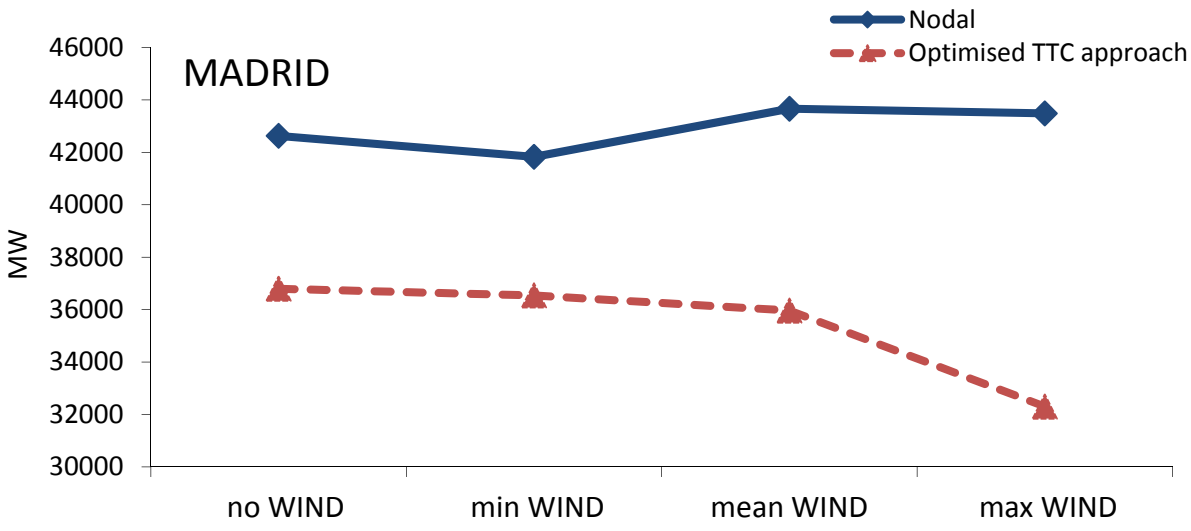
First, we consider the level of network utilization under both congestion management regimes.

Figures 10a & 10b depict the total volume of international transfers that is observed in each of scenarios. The nodal pricing approach usually leads to an increase in transfers that take place between countries, up to 34% more. Thus existing network capacity is better utilized to accommodate increasingly large volumes of intermittent energy sources. The simulation results indicate that this difference is greatest in the scenario

with maximum wind penetration: maximum international transfers are in the range of 42-43 GW in both models.

The Dresden model provides the only scenario (min wind) in which nodal pricing does not increase flows. The higher volume of international flows in the NTC case results under that wind scenario because the NTC calculations assume that the French-Spanish interconnector is utilized in the direction of Spain (which allows for higher utilization as it relaxes constraints in Southern France). The example illustrates that the volume of international transfers by itself is not the target objective, as long as the transfers are not in line with a system wide power system optimization.

The simulated increase of the volume of flows resulting from nodal pricing is likely to provide a lower bound to the benefits of nodal pricing for two reasons. Firstly, the maximum possible TTC values are calculated for each pair of neighbouring countries. It is assumed that the values for all pairs are simultaneously possible, but in practice the TTC values have to be reduced to ensure that they are jointly viable. Secondly, the large redispatch volume as simulated in the DRESDEN model would create very high costs for TSOs (with wind-spilling and load-shedding assumed to be offered at €500/MWh in that model) and ample opportunities for gaming (inc-dec game) – therefore in practice the TSO would issue lower TTC values to constrain international transfers and limit the level of domestic transmission constraints. This equally applies to the MADRID model; however, due to the joint representation of TTC and line constraints in a single step (rather than the two-step DRESDEN approach), the model does not explicitly calculate redispatch costs.



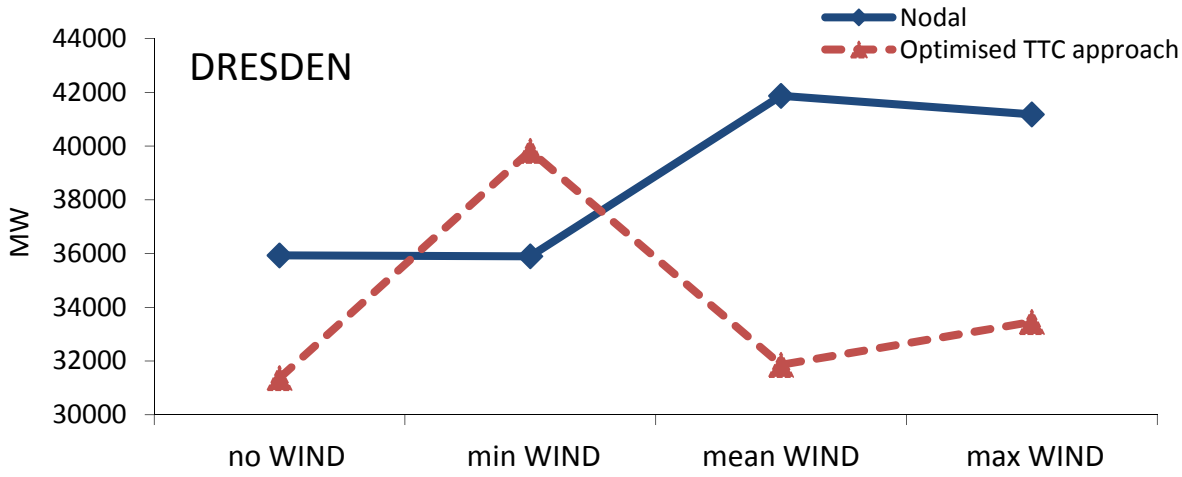


Figure 4-10a & 4-10b: International/cross-border energy transfers [MW] under varying levels of wind penetration for both models (MADRID results presented above, DRESDEN below).

Cost Savings

Finally we were interested in the total variable costs incurred for power generation. As all demand is met across the scenarios, we summed variable generation costs (reflecting both fuel and carbon costs of generators), but ignored fixed start-up and minimum run costs. The second stage in the Dresden model allowed the introduction of load shedding and/or wind spilling for balancing purposes with marginal costs of this procedure arbitrarily set at €500/MWh (greatly exceeding the marginal costs of other generation).

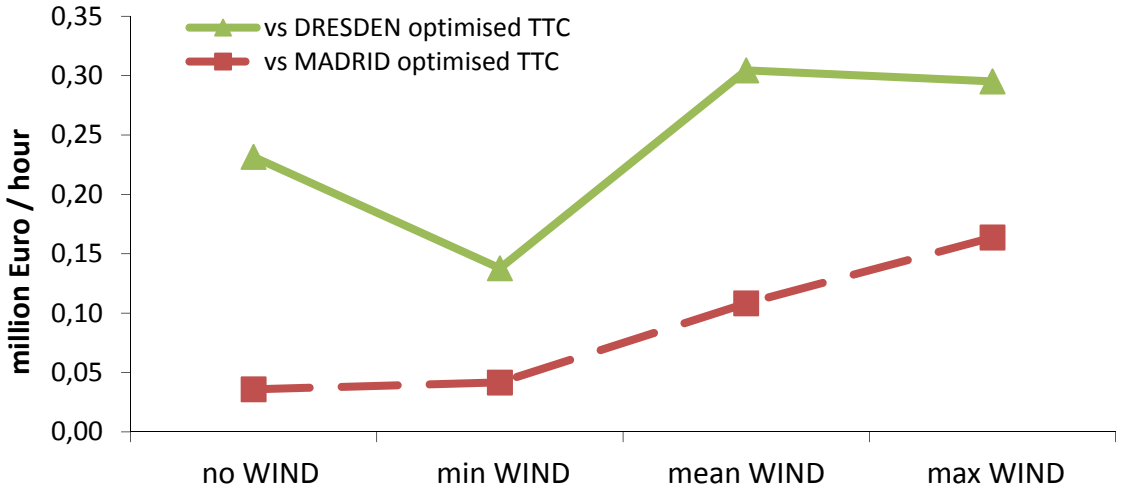


Figure 4-11: Total cost savings per hour using nodal pricing versus optimised TTC

Figure 4-11 depicts the fuel and carbon savings that were achieved through the system wide optimization possible with nodal pricing relative to zonal pricing market designs. Multiplying these values by 8760 hours/year yields estimates of annual savings that range from €0.8 - €2.0 billion depending on the penetration of wind power (representing 1.1% - 3.6% of operational costs).[42]

4.4 Discussion

Models have to abstract from many details of reality because of the lack of data or computational limitations. Thus, trade-offs are necessary when deciding upon the level of detail of the physical representation of the grid, generation and demand. In addition, the temporal dimension can be captured to different levels of detail or accuracy; from long-term investment choices to daily unit-commitment requirements or short-term representation of system flows and stability. As interconnected power systems are no longer operated according to one system-wide optimization algorithm, models could also aim to represent market design and strategic behaviour of market participants.

The focus of this paper is on the role of congestion management in the European network – hence a detailed representation of the transmission grid and spatial distribution

42 Within this calculation, we have ignored intertemporal constraints such as ramp rates. Borggrefe and Neuhoff (2010) compare the performance of zonal and nodal pricing with regard to the possibility to coordinating effective system wide intraday redispatch – and point to further benefits of nodal pricing.

of generation and load was necessary. To allow for a comparison of two different power market designs, the main characteristics of both nodal pricing and of the implicit and joint allocation of transmission capacity had to be captured in the model. This effectively exhausted the complexity that we felt comfortable to model while retaining the ability to interpret and test the model.

The simplifications inherent in a model thus raise the question, to what extent do the qualitative and quantitative model results provide evidence for the impacts of nodal pricing on real power systems? As many of the detailed characteristics of power stations, as well as system requirements like reserve requirements, are not explicitly modelled, we focused our interpretation on the model results concerning overall congestion and pricing patterns (rather than local prices or constraint volumes of a specific line) and the comparison between two power market designs based on the same system and demand configuration. Specifically, we focused on relative price levels, difference in flow volumes, and difference in system costs. Those aggregations are likely to be more reliably projected than, for instance, prices at individual buses or flows through individual lines. For these comparisons the results of the different models are broadly consistent with each other and with observed market prices, and remaining differences can be explained by the different modelling approaches.

4.4.1 Results from other studies

It is intriguing to observe that the modelling exercise confirms observations from existing nodal pricing-based systems in the US:

- Mansur and White (2009) studied PJM and AEP/Dayton/ComEd operations before and after their merger. Their studies show that the volume of commercial transaction between the geographical regions increased by approximately 42% after the integration of both markets. The increase is consistent without simulation results that showed up to a 34% increase in international flows. The incremental benefit of extending nodal pricing to the AEP/Dayton/ComEd areas to PJM was $180 million annually, which multiplied by the size ratios (50 GW for the three states, 820 GW EU) translates to a gain of $2.95 billion. As US fuel prices in 2009 measured in USD roughly correspond to EU fuel prices in Euro, the results can be interpreted as system savings of €2.95 billion. PJM estimates that the overall benefits of integrated operation of their system are $2.2 billion (approximately €1.8 billion) annually (Ott, 2010).
- Analysis from nodal pricing-based operations in Texas (Watson, 2011) revealed that the ERCOT system could have helped avoid potentially “millions, or hundreds of millions [USD]” if it had been implemented before a 2008 spike in power price. The sys-

tem, which went fully operation December 2010, has reportedly already reduced prices by 25%-33% compared to December 2009 because the increased granularity of the power market design allows for more precise operations.

In addition to this experience, other simulations have quantified the benefits of nodal pricing for international coordination of dispatch. For instance, van der Weijde and Hobbs (2010) simulate both nodal and zonal power market designs on a four-node model and find that coordinated international redispatch can save up to 10% of system unit commitment and dispatch costs relative to a TTC-type market outcome. As the coordinated international redispatch – in their model – reinstates a configuration of power production that is similar to nodal pricing, the 10% savings can be interpreted as the savings of nodal pricing relative to TTC-type approach. Most of these savings are due to the ability to adjust international MW flows in balancing markets; if international rebalancing is allowed in a NTC system, then the cost savings of instead using nodal pricing are an order of magnitude smaller, but still significant.

The high value of these savings (more than three times our simulation results) relates to the higher level of congestion in the network, and the additional constraints imposed by the small number of generators in the model that can contribute to resolving the constraint.[43]

In another simulation study, Barth et al. (2009) obtain an estimated LMP benefit (compared to an NTC system) of 0.1% of system variable cost for the EU in the year 2015 under more than 125 GW of wind capacity. These benefits are a combination of improved efficiency of international transactions, within-country dispatch, and day-ahead unit commitment that considers all international network constraints instead of NTCs. However, they treat each country as a single zone with no consideration of individual circuits between countries or congestion within countries, therefore, this estimate should be viewed as a lower bound.

In other simulation studies, Oggioni and Smeers (2009) use a simple six-node network to examine the benefit of coordinated international balancing markets. Market coupling based upon nodal pricing is found to be more efficient than using NTCs. Meanwhile, Vandezande et al. (2009) provide an estimated benefit of coordinated balancing be-

43 Note that in practice, international coordinated redispatch would incur significantly higher costs than indicated by simulation results. This is because the simulation assumed that the system operator would know marginal generation costs of all units and would be able to redispatch all units at these costs.

tween Belgium and The Netherlands (compared to no international redispatch) to be approximately 40% of total balancing costs.[44]

Thus, we conclude that the empirical evidence and results from other modelling confirm that significant cost savings would likely result from a shift to nodal pricing-based congestion management on a European scale.

To the extent that initial implementation of a nodal market design will be limited to part of the EU region, only parts of these savings will be generated. However, improvements to the power market design can also offer additional savings where system-wide intraday optimization (as possible in nodal pricing related power market designs) allows for effective use of the better wind forecasts that appear during the day. Also, the benefits of transparent information on congested lines for network expansion decisions and public engagement during the planning process have not been quantified.

4.4.2 EU transition to nodal pricing market design

Clearly, shifting to a nodal power market design would require considerable changes in the institutional settings in Europe. The current separation of power exchanges and grid operation would have to be abandoned in favour of an integrated ISO (Independent System Operator) or closely coordinated ISOs, at least for the day-ahead and intraday market. Future and other derivative markets can be handled by one or several institutions distinct from the system and spot market operator; nevertheless, such institutional changes raise several objections even beyond the evident self-interests of some of the current players in the markets. Four major concerns may be identified:

- Feasibility. The entire European system is larger (600+ GW) than the PJM area (160+ GW), therefore the algorithms for optimal commitment and dispatch will require more computation time. This clearly has to be checked carefully, but the improvements in computer and algorithm performance have been tremendous over the last decade, and further improvements are expected to come. Thus, the importance of this constraint is likely to fade away over time; even if it is possibly relevant today

44 Other studies have examined the benefits of LMP, but not specifically relative to NTC-based management of intercountry constraints. Green (2007) estimates that LMP would provide efficiency benefits equal to about 1.5% of generator revenues in the UK due to better dispatch and demand response to prices. Leuthold et al. (2005) estimate that LMP would provide a 0.6-1.3% increase in economic surplus in the German power markets. A further 1% gain would result if more wind capacity is built because of increased congestion. Weigt (2006) extends that model to include unit commitment of aggregations of power plants and international transmission. He obtains a benefit equal to 0.06% of the market surplus for all of Europe, including a net 0.79% increase in consumer surplus which is partially offset by decreases in profits.

at a full European scale, it is certainly not relevant for an implementation in a limited number of European states in the next years.

- Security. Today accountability for system security in Europe rests on the shoulders of the control zone operators (TSOs) at a decentralized level. Shifting this responsibility to a more central level is feared by some to reduce system security. Although this argument sounds convincing at first sight, there are also counter-arguments. The PJM experience shows that centralized operation does not mean increased unreliability, e.g., the territory covered by PJM was saved from the large scale August 2003 blackout across the northeast USA and some Canadian provinces because an integrated real time dispatch algorithm provided timely and accurate information that allowed for quick responses. A coordination of real-time responses to disturbance may hence even contribute to increased system security. Alternatively, it is possible to maintain the real-time operation and security responsibility at a decentralized level even with centralized day-ahead and intraday dispatch. The shift in responsibility would then occur at gate closure (e.g., 1-2 hours from real time). This would obviously raise several coordination issues, but these would be of a technical nature and could be solved, see Baldick et al. (1999) and Aguado and Quintana (2001).
- Market Liquidity. The argument here is that large areas with uniform prices encompass multiple agents, thus inducing more liquid markets. In turn, this creates more hedging possibilities, helping in particular smaller power plant operators. This issue certainly requires further investigation, yet the financial hedging using derivatives may still be concentrated on one reference product (like Brent or WTI in the oil market). This reference product may correspond to some particular node in the system (like Henry Hub for US gas contracts), or it may be a virtual system point or system average (like the Nordel system marginal price). Locational deviations from this reference price, as far as they are temporary and stochastic, will largely level out over a month or year and thus do not constitute a major risk for the individual plant operator. If the deviations by contrast are systematic, then they provide a clear locational signal for power plant investors. Moreover, Financial Transmission Rights (FTR) may be used to hedge locational spreads (O'Neill et al., 2008).
- Lack of institutional competition. Ockenfels et al. (2008) argue that the centralization of operation decisions eliminates the competition between different trading institutions (e.g., power exchanges vs. OTC trading). Also the competition between different power plant operation strategies characteristic for today's bilateral and voluntary trading arrangements is at first sight replaced by one centralized dispatch algorithm. However, in the US organized markets, independent power exchanges coexist with the formal ISO markets, and there are multiple trading institutions that deal in forward products. Obviously in this dispatch algorithm, power plant owners still may influence the operation of their power plants through the bids which they submit to the system operator, or they can self-schedule, accepting whatever prices the market offers. A delicate issue certainly is to what extent cost-based bids will be required by the ISO: PJM and the California ISO, for instance, require them as a back-

up to be used in the case congestion creates opportunities for exercising local market power (O'Neill et al., 2008).

These and other issues certainly have to be discussed in detail when it comes to implementing nodal pricing in practice. Yet the analysis presented here at least provides a clear economic rationale for moving further ahead in this direction.

4.5 Conclusion

An important issue for large scale renewable energy integration within Europe is the more efficient use of and development of additional network capacities, and managing congestion problems.

This paper sets out to explore whether the choice of the design of EU spot power markets makes a difference for the effective integration of renewables. Two market designs are compared across Europe: (i) an optimized approach of implicit auctions of transmission capacity between nationally defined price zones; and (ii) a nodal pricing approach.

The analysis has some limitations. In particular, the quality of the available data has some problems, and is certainly insufficient to allow for the evaluation of individual lines or investment projects. However, for the aggregate analysis presented here, the data is adequate, and is of better quality than that used in any previously published EU-wide analysis of this issue.

Additionally, specific operation constraints, e.g., for system security considerations, are omitted since generally these are not formally implemented or published by European TSOs but instead are carried out informally by the operators based on established practices.

Simulating nodal prices with the data set provides a second set of insights that confirms previous studies. Most of the transmission constraints are not associated with lines between countries, but with lines within countries. The current European power market design (outside of Scandinavia) does not make this explicit. This creates incentives for system operators to limit international flows to avoid domestic congestion that requires redispatching of power stations within their boundaries to resolve remaining constraints. Furthermore, the nodal pricing simulations illustrate that the congestion – and price – patterns vary considerably between wind scenarios. This suggests that approaches that aim to define price zones within countries are not suitable to address internal congestion, as the zones would either have to vary depending on system con-

ditions (impractical for contracting purposes), or be small (and thus be essentially equivalent to nodal pricing).

Finally, the two models (MADRID and DRESDEN) are used to calculate TTC values for limits to commercial transfers between countries. As no formal standardized method exists for TTC calculations, and national TSOs do not report on their specific methodology, we explore a range of methodologies that capture some of the variations that might be inherent in current TTC calculations. These TTC values are then used as a basis for modelling the single price zones according to national boundaries with one implicit auction for all international transmission capacity. The comparison with the nodal pricing results suggests that some €0.8 - €2.0 billion cost savings per year and an increased use of international transmission capacity by up to 34% is possible with nodal pricing. These results are broadly consistent with empirical values from the USA and other simulation models.

Based on these results, further research should address the issue whether the resulting efficiency improvements and increased transparency justifies the cost of implementing new systems, and whether the political effort necessary to change the current design is achievable.

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ANNEX

A. Methodologies: TTC Calculation and the two Models for Nodal Prices

A.1 Survey of TTC methodologies

International capacity allocations distinguish between commercial transfer limits (which are used by market participants to plan their cross-border trades), and physical values (as used by system operators in real-time operation (ETSO, 2001a)). The following descriptions refer to the former, i.e. the determination of limits on commercial exchange programs; direct quotations from ETSO's guidelines are indicated by italics.

Total Transfer Capacity (TTC) *is the maximum exchange program between two areas compatible with operational security standards applicable at each system if future network conditions, generation and load patterns were perfectly known in advance*.

The computation of TTC starts with establishing a Base Case Exchange (BCE), based on the best available information on network conditions, generation and load patterns, and planned cross-border transactions. To compute the TTC from area A to area B, generation is increased stepwise in area A and decreased in area B, maintaining loads the same, until security limits in either system A or B are reached:

$$TTC = BCE + \Delta E$$

where ΔE is the maximum increase in transfer before security limits are breached.

An additional security margin, the Transmission Reliability Margin (TRM), *is imposed to account for uncertainties arising from the functioning of frequency regulation, emergency exchanges, and inaccuracies in data and measurements*.

The TRM *is determined by each TSO in order to guarantee the operation security of its own power system*. In other words, the TRM translates the somewhat abstract representation of transfers contained in the TTC determination into limits on scheduled commercial transfers that result in manageable physical transfers in real time.

Net Transfer Capacity (NTC) *is the maximum exchange program between two areas compatible with security standards applicable in both areas and taking into account the technical uncertainties on future network conditions*. It is defined as:

$$NTC = TTC - TRM$$

The TTC, TRM and NTC values for a given pair of areas can be different for transfers in opposite directions. ENTSO-E publishes a table of "Indicative values for NTCs in Europe" on its website twice a year.

Operationally, there are three allowed options for modelling the transfer of generation between areas in TTC calculations (UCTE, 2004):

- Method A: Each chosen injection is scaled in proportion to the remaining available capacity at the relevant generator node. The value of ΔEmax (i.e., TTC-BCE) is determined when either all generators reach their maximum outputs, or if a network operational (N-1 security) limit is reached. This method brings the key advantage that physical generator output limits are respected. The UCTE Handbook states that it should therefore be used under normal circumstances.
- Method B: If the necessary data on generation limits for the first method are not available, the generator outputs may be scaled without consideration of output limits.
- Method C: The generator outputs are modified according to merit order, with limits on output being respected.

In this study MADRID and DRESDEN models are both based on "Method C." As described in the next section, MADRID's model can be interpreted as more conservative than DRESDEN with respect to system generation costs.

As mentioned above, detailed information is available on methods for TTC calculation. However, NTC determination is more difficult, as the public information on methods used for determining TRMs is limited. ETSO (2001b) suggests that the margin required for load-frequency control can be determined by statistical analysis of historical time series, and that the margins required for reserve sharing and emergency transfers should be agreed upon between operators. It also discusses how these components of the TRM should be combined. However, the precise calculations are not described in that source, and cannot be duplicated based on that information.

Operational experience from three control areas illustrates the differences in the methods that different TSOs use to determine TRMs. This diversity of methods prevents a comparison of modelled and actually announced values by the TSOs, as discussed in Section 4.3.4:

- For Nordpool, ENTSO-E (2010) states that in practice, the TRMs between areas in Nordpool are based on transfers due to frequency regulation only. It gives the current TRM values used as 100 MW between Sweden and Finland, 150 MW between Sweden and southeastern Norway, and 50 MW for most of the remaining connections. A further description for the specific case of Finland is given in Fingrid (2009).

- To determine the TRM, a number of the German TSOs (EnBW, VE Transmission, RWE, Transport 2009) use a heuristic formula. They multiply the square root of the number of connection circuits between control zones with 100 MW to obtain the TRM. Some examples of the numbers of cross-border circuits are 4 (Germany to France), 6 (Germany to Netherlands), 15 (Germany to Switzerland), and 12 (Germany to Austria).
- Information supplied directly to us by the Polish System Operator (PSE Operator S.A.) confirms that there are no universal regulations defining the TRM determination process; the TRM is said to be lower for shorter time horizons, when uncertainty is reduced.

A.2 Nodal Pricing Model

We now describe the methodologies that we use to calculate nodal pricing, in this section, and TTC. We used the Ecofys, Madrid, and Dresden models to calculate the nodal dispatch across the EU. The nodal pricing model determines the cost minimizing dispatch **g** of power plants respecting economic and technical restrictions, namely energy balance, line capacity limitations, and minimum and maximum generation capacity limits.

The energy balance ensures the balance of demand $\mathbf{d_0}$, generation of thermal power plants **g**, renewable wind generation **w**, and nodal injections or withdrawals from the network $\mathbf{B\theta}$ (i.e., a linearized load flow that expresses transmission flows as a linear function of voltage angles). To allow for the possibility of wind spillage, wind generation **w** is variable and bounded by the available wind generation $\mathbf{w_0}$.

Thermal power generation is restricted by their minimum generation requirement $\mathbf{g^-}$ and the maximum available capacity $\mathbf{g^+}$. To incorporate minimum generation constraints, a binary status variable **u** is introduced, indicating the operating status of a power plant. In a unit commitment model, **u** is a decision variable; in a dispatch model, it is predetermined.

The power flow and resulting nodal injection or withdrawal are based on DC load flow equations (e.g., Schweppe et al., 1988) and restricted by maximum thermal transmission capacity $\mathbf{f^+}$. Transmission losses are neglected. Locational marginal prices are defined as the dual variable of the energy balance. The final mixed integer linear program for the unit commitment problem is shown in (1).

Equation (1)

$$
\begin{aligned}
\min \quad & \mathbf{mc}^{T} \cdot \mathbf{g} \\
\text{s.t.} \quad & \mathbf{B} \cdot \boldsymbol{\theta} - \mathbf{g} + \mathbf{d}_0 - \mathbf{w} = 0 \\
& -\mathbf{f}^{+} \leq \mathbf{H} \cdot \boldsymbol{\theta} \leq \mathbf{f}^{+} \\
& \mathbf{u} \cdot \mathbf{g}^{-} \leq \mathbf{g} \leq \mathbf{u} \cdot \mathbf{g}^{+} \\
& \mathbf{0} \leq \mathbf{w} \leq \mathbf{w}_0
\end{aligned}
$$

where:

mc: Marginal costs

g: Bus power generation

B :Nodal susceptance matrix

θ: Bus angles vector

$\mathbf{d_0}$: Initial bus power demand

w: Bus wind generation

$\mathbf{w_0}$: Available bus wind generation

H: Branch susceptance matrix

$\mathbf{f^+}$: Branches maximum power flow

u: Binary power plant status variable {0,1}

$\mathbf{g^-}$: Minimum capacity of generation units

$\mathbf{g^+}$: Maximum capacity of generation units.

We apply more than one variant of the above nodal pricing model. The ECOFYS and MADRID models assume that all power plants in the system to be online. Thus vector **u** is fixed to one and power plants have to produce within their minimum and maximum capacities. Consequently, the problem reduces to a linear program with a fixed unit commitment. On the other hand, the DRESDEN model optimizes the unit commitment of power plants and the power plant dispatch simultaneously treating **u** as a variable. Hence, results of different nodal pricing models can be interpreted as more conservative (in the case of MADRID and ECOFYS) and more optimistic estimates (in the case

of DRESDEN) with respect to system generation costs, since DRESDEN provides more flexibility.

Given this formulation of the nodal pricing model, both MADRID and DRESDEN compute total transfer capacities (TTC). Simulations are made following a two-step method. First, TTC values are computed. Second, using this computed TTC, system dispatch is simulated under different assumptions to calculate resulting international flows.

A.3 Calculation of the TTC capacity in the MADRID model

Several possible ways exist for computing the total transfer capacity (TTC) between neighbouring countries. The following method can be viewed as an implementation of "Method C" from Section A.1 above as generation is determined endogenously. Demand in country A is incremented exogenously in an iterative fashion, whereas generation in country B is increased endogenously in response to serve the additional demand until physical limits (either transmission limits or generation bounds) are reached.

Equation (2)

$$\begin{aligned} &\max\ \lambda \\ &\text{s.t.}\ \ \mathbf{B}\cdot\boldsymbol{\theta}-\mathbf{g}+(\mathbf{d}_0+\lambda\cdot\mathbf{d}_\lambda)=0 \\ &\qquad -\mathbf{f}^+\le\mathbf{H}\cdot\boldsymbol{\theta}\le\mathbf{f}^+ \\ &\qquad \mathbf{g}^-\le\mathbf{g}\le\mathbf{g}^+ \end{aligned}$$

where:

λ: Transfer capability parameterization factor

$\mathbf{d}_\lambda$: Bus power demand evolution vector.

Mathematically, TTCs are computed by maximizing the additional demand $\boldsymbol{\lambda}\mathbf{d}_\lambda$ in country A which can be served by additional generation **g** in country B. The bus power demand evolution vector $\mathbf{d}_\lambda$ is proportional to the demand in country A. Only generators in country B are included in vector **g** whereas for the rest of the system, generation is a fixed power injection. The optimization is performed for each pair of neighbouring countries. The TTC value is given by adding the total demand increment $\boldsymbol{\lambda}\mathbf{d}_\lambda$ (i.e., the sum of its components). Generation cost values are not considered when computing the TTC by this method.

There are two different methods to model how TTC values could be used by TSOs in order to constrain international exchanges. In the first method, it is assumed that TSOs in countries A and B constrain the physical flow across the border to the TTC value. The associated linear program is:

Equation (3)

$$\begin{aligned} \min\ & \mathbf{mc}^T \cdot \mathbf{g} \\ \text{s.t.}\ & \mathbf{B} \cdot \boldsymbol{\theta} - \mathbf{g} + \mathbf{d}_0 - \mathbf{w} = 0 \\ & -\mathbf{f}^+ \le \mathbf{H} \cdot \boldsymbol{\theta} \le \mathbf{f}^+ \\ & \mathbf{g}^- \le \mathbf{g} \le \mathbf{g}^+ \\ & \boldsymbol{\theta} \le \mathbf{w} \le \mathbf{w}_0 \\ & -TTC_{B \to A} \le \mathbf{e}_{A \to B}^T \cdot \mathbf{H} \cdot \boldsymbol{\theta} \le TTC_{A \to B} \quad \forall A, B \end{aligned}$$

where the new notation is:

$TTC_{\mathbf{A\text{->}B}}$: TTC value from country A to B

$\mathbf{e}_{\mathbf{A\text{->}B}}$: Vector to select border branches between countries A and B. Its components are +1 if the branch crosses from A to B, -1 if it crosses from B to A and 0 otherwise.

The second model instead assumes that TTC values are used in order to constrain the interchanges by setting bounds of the flows between countries. A notional transmission network is assumed consisting of the different countries as nodes. The flows across the branches in the notional network joining the different countries are bounded by the TTC values (see Figure i below). The notional network is a pure transhipment (or path-based) network, i.e., no second (voltage) Kirchhoff law is enforced on it. However, the model considers a fixed split between direct and indirect exports from one country to another; for instance, that energy exports from country A and B are partially direct transfers from A to B, and partially indirect transfers through C. In that respect, it models the underlying reality more accurately than a pure transhipment network. If the second Kirchhoff law were also considered, the presently preferred Load Flow Based Allocation approach would be obtained.

The associated mathematical program is:

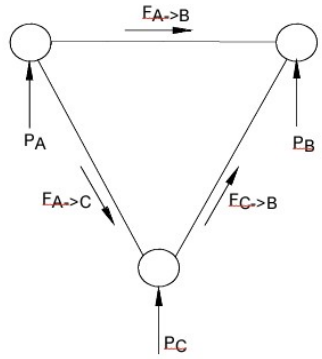

Figure i: Mathematical program representing notional transmission network between three countries.

Equation (4)

$$
\begin{aligned}
&\min\ \mathbf{mc}^T \cdot \mathbf{g} \\
&\text{s.t.}\ \mathbf{B}\cdot\boldsymbol{\theta} - \mathbf{g} + \mathbf{d}_0 - \mathbf{w} = 0 \\
&\quad -\mathbf{f}^+ \le \mathbf{H}\cdot\boldsymbol{\theta} \le \mathbf{f}^+ \\
&\quad \mathbf{g}^- \le \mathbf{g} \le \mathbf{g}^+ \\
&\quad \mathbf{0} \le \mathbf{w} \le \mathbf{w}_0 \\
&\quad \mathbf{e}_A^T \cdot (\mathbf{g} - \mathbf{d}_0 + \mathbf{w}) = P_A \quad \forall A \\
&\quad P_A = \sum_B F_{A\to B} \quad \forall A \\
&\quad -TTC_{B\to A} \le F_{A\to B} \le TTC_{A\to B} \quad \forall A, B
\end{aligned}
$$

where the new symbols are:

$F_{\mathbf{A\text{->}B}}$: Flow in the notional network between from country A to B

$P_{\mathbf{A}}$: Net generation in country A

$\mathbf{e}_{\mathbf{A}}$: Vector to select buses belonging to country A.

Criteria for TTC computation should be consistent with its use in dispatching. The methodology above clearly fails on these criteria. TTC computation makes full use of the available network (for instance, the computed TTC between France and Germany assumes that the Belgian, Dutch, Swiss and other networks are also used). In this regard it is expected to be close to the maximum sensible value. On the other hand, this relatively large TTC value is allocated to entities connecting just France and Germany, that is, the set of circuits physically linking France and Germany or the branch in the

notional network joining France and Germany. Therefore this value is likely to be over-generous. Even so, the TTC constraints are binding in many simulated scenarios.

In summary, the MADRID model provides a conservative (e.g., lower bound) estimate of the benefits of moving from TTC type congestion management to a nodal pricing regime which incorporates dispatch management. This is because the TTC simulations are based on two favourable assumptions. First, generous TTC values are assumed. Second, the system operators are assumed to be able to call on the least cost power stations when re-dispatching the system to address internal constraints, and only need to pay the marginal price for each station rather than market clearing price or premia for opportunity costs or market power.

A.4 Calculation of the TTC capacity in the DRESDEN model

This TTC calculation approach follows "Method C" of Section A.1 using an economic dispatch model with DC load flow constraints. In order to calculate the TTC between neighbouring countries, the nodal pricing model (1) is extended by equation set (5). Each country is characterized by a specified net export position $netexport^{BCE}$, which corresponds to an agreed base case (BCE) and defined international transactional exchanges. To allow an adjustment of the net export position, the parameter *Δnetexport* is introduced and successively increased in country A and decreased in country B during the calculation procedure. The change in the net export position of a country has to be counterbalanced by the generation dispatch.

Equation (5)

$$\mathbf{e}_A^T \cdot \mathbf{g} - \mathbf{e}_A^T \cdot \mathbf{d}_0 = netexport_A^{BCE} + \Delta netexport_A^{A\to B} \quad \forall A$$
$$\Delta netexport_B^{A\to B} = -\Delta netexport_A^{A\to B}$$

where the new symbols are:

$\mathbf{e_A}$: Vector indicating the nodes of country A; +1 if node belongs to country A

$netexport^{BCE}_A$: Base case net export position of country A

$\Delta netexport^{A\to B}_A$: Increase of net export position of country A for border A→B.

The calculation procedure works as follows. In the first step the generation dispatch and power plant status is optimized for a defined base case. In order to determine the additional bilateral exchanges, the net export position of two neighbouring countries is changed (a stepwise increase of *Δnetexport* in one country and vice versa).

The unit commitment **u** and the dispatch of power plants **g** in both countries is optimized using an economic dispatch. The unit commitment in the remaining countries is fixed to the base case commitment whereas re-dispatching of power plants is allowed. The demand is fixed at the initial demand $\mathbf{d_0}$ and not changed during the optimization procedure. If a feasible commitment and dispatch is found, the calculation procedure continues and the net export position is further increased or decreased respectively. Otherwise the procedure stops and the total increase of bilateral exchanges (*Δnetexport*) reflects the maximum additional exchange (*ΔE*) according to the TTC definition.

The calculation procedure is performed for each combination of neighbouring countries. Finally, the total transfer capacity (TTC) is calculated as the initial transfer of the base case plus the maximum possible additional transfer *Δnetexport* following the definition in Annex A.1. The calculated total transfer capacity reflects the maximum exchange, which can be technically managed by the national power systems through adjustments of generation commitment and dispatch. Corresponding generation costs can be considered as an additional economic criterion for the determination of the maximum allowable additional exchanges.

Given the calculated total transfer capacity between European countries, the unit commitment and dispatch of power plants are optimized in two steps. Firstly, the unit commitment of power plants is optimized subject to limitations on international trade. The total transfer capacity represents the upper limit on international trades between neighbouring countries. Physical international and national network constraints are not considered, as international trades refer to transactional exchanges between European countries. This step represents the stylized day-ahead market procedure in most European countries. The mixed integer linear program is as follows:

Equation (6)

$$
\begin{aligned}
\min\ & \mathbf{mc}^T \cdot \mathbf{g} \\
\text{s.t.}\ & \mathbf{PE} \cdot \mathbf{e} - \mathbf{PE}^T \cdot \mathbf{e} - \mathbf{g} + \mathbf{d}_0 - \mathbf{w} = 0 \\
& \mathbf{u} \cdot \mathbf{g}^- \le \mathbf{g} \le \mathbf{u} \cdot \mathbf{g}^+ \\
& \mathbf{0} \le \mathbf{w} \le \mathbf{w}_0 \\
& 0 \le \mathbf{e}_A^T \cdot \mathbf{PE} \cdot \mathbf{e}_B \le TTC_{A \to B} \qquad \forall A, B
\end{aligned}
$$

where the new symbols are:

e: Vector with ones

PE: Exchange variables between nodes of the network

The power plant dispatch is optimized in the second step using the nodal pricing model (1) subject to physical network constraints (power flow limitations and DC load flow constraints). Hence physical network congestion is introduced and has to be managed using short-term congestion alleviation methods in the form of re-dispatch of power plants. However, the flexibility of power plants is limited as the unit commitment is fixed to the values of the first optimization step. The exception is that the unit commitment of fast starting gas-turbine power plants is not fixed due to their technical flexibility. Beside the power plant dispatch, wind spilling and load shedding are introduced as additional short-term congestion alleviation options.