European Smart Power Market Project

Executive Summary

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Background and Scope

In the EU, at least 200 gigawatts (GWs) of new and additional renewable energy sources may be needed by 2020. However, the existing EU power market design utilising regional/zonal pricing risks impeding the required rate of development to meet several EU medium-term carbon and energy targets. Specifically, we identified the following challenges to European power market designs:

- Current approach to congestion within countries limits cross-border flows;
- Regional/zonal pricing does not adequately reflect system state and does not provide appropriate signals to encourage investment;
- The lack of system-wide information-sharing does not maximize the potential resources available and results in the inefficient incorporation of variable energy sources.

Below are the major findings and implications from the studies we carried out with regards to the current power market design in the EU[1]:

- K. Neuhoff (CPI Berlin), B. Hobbs & D. Newbery (Electricity Policy Research Group, University of Cambridge): *Congestion Management in European Power Networks*, 2011.
- F. Borggrefe (University of Cologne) & K. Neuhoff: *Balancing and Intraday Market Design: Options for Wind Integration*, 2011.
- K. Neuhoff: *A Smart Power Market at the Centre of a Smart Grid*, 2011.
- K. Neuhoff, R. Boyd & T. Grau (CPI Berlin), J. Barquin & F. Echavarren (Universidad Pontificia Comillas), J. Bialek & C. Dent (Durham University), C. von Hirschhausen (TU Berlin), B. Hobbs, F. Kunz & H. Weigt (TU Dresden), C. Nabe & G. Papaefthymiou (Ecofys Germany) and C. Weber (Duisberg-Essen University): *Renewable Electric Energy Integration: Quantifying the Value of Design of Markets for International Transmission Capacity*, 2011.
- K. Neuhoff & R. Boyd: *Frequently asked questions on the international experience with nodal pricing implementation*.

Findings and Implications

Through various qualitative and quantitative studies detailed below, we explore whether the current European power market designs foster the transition to low-carbon energy. Using an international comparison, we find that the approaches currently pursued across EU countries do not provide an effective framework for the widespread adoption of many GWs of on- and off-shore intermittent power:

- The current structure does not make effective use of network transmission capacity, thus increasing costs and risking delays for renewable energy connections – see **Section A**;
- It does not use improvements in wind forecasts during the day to optimise European system dispatch, to save costs and emissions – see **Section B**;
- In addition, it does not create transparent signals about system constraints to inform transmission network investment decisions.

We conclude that implementing an integrated market utilising a nodal or locational marginal pricing (LMP) approach addresses the needs. See **Section C** for quantitative findings and implications.

[1] See www.climatepolicyinitiative.org for access to the papers.

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.

The EU electricity regulator, ERGEG[2], proposed a short-run market design based on market coupling and expanding market coupling to address congestion. However, the topology of the European power network does not follow national boundaries and significant congestion occurs both between and within countries.

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 C**).

Table 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: 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

[2] European Regulators' Group for Electricity and Gas (ERGEG), www.energy-regulators,eu.

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 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 2009.

To meet this additional demand for reserve and response operations, intraday and balancing markets need to be adjusted to allow the TSOs to appropriately respond to increased uncertainty.

After comparing different EU power market designs, we determined that a nodal pricing approach provides appropriate price signals for the economic design and evaluation of power grids, encourages the effective use of transmission capacity and improved interfaces between onshore and offshore networks, even between regions.

Table 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[3] 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[4] 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:

International transfers. The nodal pricing approach leads to an **increase of up to 34% in international MW transfers between countries compared to the current EU model**, depending on wind power penetration. This means that the existing network capacity can adequately accommodate large volumes of intermittent energy sources. In both models, the sum of all cross-border transfers reaches 43 GW at maximum wind output.

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 represents an average of 1.1% - 3.6% of operational costs[5]. 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.

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[3] Schweppe et al. (1988) and Hogan (1992 - *Contract Networks for Electric Power Transmission*, J. Reg. Econ 4 (3).
[4] Madrid Universidad Pontificia Comillas and Dresden University of Technology.
[5] These do not include possible savings in unit commitment costs such as start-up and minimum run costs.

Descriptors

CPI Area of Focus: Institutional Issues, Removing Barriers / Complementary Policies
Sector: Power and Energy
Region: Europe
Keywords: Power market design, integrating renewables
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