Relevance of established national bidding areas for European power market integration – an approach to welfare oriented evaluation

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Abbreviations

- ACER= Agency for Cooperation of Energy Regulators
- APX-Endex= British-Dutch Energy Exchange
- BETTA= British Electricity Transmission and Trading Arrangements
- BKartA= Bundeskartellamt
- BNetzA= Bundesnetzagentur
- CACM= Capacity Allocation and Congestion Management
- CfD= Contracts for differences
- CWE= Central-Western Europe
- CZ= Czech Republic
- DE= Germany
- DK= Denmark
- EdF= Électricité de France
- EEA=European Economic Area
- EEX= European Energy Exchange
- Epex= European Power Exchange
- EMCC= European Market Coupling Company
- EnLAG= Energieleitungsausbaugesetz
- EnWG= Energiewirtschaftsgesetz
- ERGEG= European Regulators' Group for Electricity and Gas
- ERI= Electricity Regional Initiative
- EU= European Union

- EU Com= European Commission
- FBA= Flow-based allocation
- FR= France
- FTR= Financial Transmission Rights
- GWB= Gesetz gegen Wettbewerbsbeschränkungen
- Hz= Hertz
- ITC-Mechanism= Inter-TSO-Compensation-Mechanism
- KWK = Kraft-Wärme-Kopplung (combined heat and power)
- L.L.C= Limited Liability Company
- NABEG= Netzausbaubeschleunigungsgesetz
- NETA= New Electricity Trading Arrangements
- NL= Netherlands
- NTC= Net transfer capacity
- Ofgem= UK Office of Gas and Electricity Markets
- ÖSPI= Austrian Power Price Index
- OTC= Over the counter
- PHELIX= Physical Electricity Index
- PJM= Pennsylvania-New Jersey-Maryland
- PL= Poland
- PTDF= Power Transfer Distribution Factors
- PV= Photovoltaics
- TWh= Terawatt hour
- TSO= Transmission system operator

- UK= United Kingdom
- VIK= Verband der Industriellen Energie- und Kraftwirtschaft e. V.

Abbreviations

1 Background and scope of the study

1.1 Context

Germany and other EU countries face increasing challenges in facilitating changing load flow situations on the extra high voltage grids. These changes are driven by the need to integrate new renewable energy generation, but also by a restructuring in the topology of conventional power generation and the evolution of power demand. Without further action there would be an increasing need to curtail or redispatch power generation away from cost-minimising patterns in order to relieve congestion and bottlenecks on the system.

1.2 Options for relieving congestion

There are a number of means of dealing with these challenges.

- Measures that fundamentally relieve congestion include:
  - grid investment and reinforcement; and
  - management of the location of new power stations and loads.
- Measures that have a more short term and operation effect include:
  - the market based control of injections and loads e.g. by market splitting (e.g. splitting wider bidding areas into smaller zones within which no or only little congestion arises); and
  - redispatching power stations close to real-time.

There is no generic answer as to which actions should be prioritised and how they should ideally be combined. The optimal solution needs to take into account the specific local situation.

1.2.1 Discussion so far in Germany

For the case of Germany, previous studies have concluded that:[1]

- On a number of key routes, grid expansion and investment should be prioritised.

[1] Frontier Economics/Consentec, *Methodische Fragen bei der Bewirtschaftung innerdeutscher Engpässe im Übertragungsnetz (Energie)*, 2008; Frontier Economics/Consentec, *Notwendigkeit und Ausgestaltung geeigneter Anreize für eine verbrauchsnahe und bedarfsgerechte Errichtung neuer Kraftwerke*, 2008.

- Some management of locating new power stations could be desirable in future, but would need to be developed in a stable manner, especially with the aim of
  - locating new gas fired power generation close to loads; and
  - locating coal stations along the Rhine.
- The option to redispatch power stations needs to be upheld for security reasons.

Based on recommendations along these lines the Bundesnetzagentur – in 2008 – had decided to continue with countertrading and redispatch as the core operational measures (i.e. not to pursue market splitting within Germany), but to monitor progress on grid expansion to ensure that the more fundamental solutions do actually take effect.

1.2.2 Recent market developments

In part the market has not evolved as anticipated:

- Network development – There have been significant delays in the development of the German (onshore) grid. Key restructuring and expansion projects for North-South transits are still at the planning and authorisation stage.
- Generation development:
  - Wind expansion – as was expected wind generation in Germany has further expanded, causing increasing loop flows on neighbouring systems. However, especially offshore generation has not grown as much as expected.
  - PV expansion – Germany has also experienced a significant expansion of photovoltaic (PV) generation in the South and thereby relatively close to loads. PV expansion raises grid issues at the local and low voltage level, which are however not significant for the consideration of congestion in the extra high voltage grid.

The net effect of these developments and departures from expected trends is complex and not obvious a priori. It requires further analysis, partly through this study.

1.3 Recent policy developments

Since BNetzA last reviewed the situation there have been a number of relevant developments in the policy debate:

- ERGEG Framework Guidelines on Capacity Allocation and Congestion Management for Electricity;
- an EU Com Decision on Svenska Kraftnät; and
- the introduction of CWE Market Coupling.

ERGEG Framework Guidelines on Capacity Allocation and Congestion Management for Electricity[2]

The Guidelines state that „*The overarching objective of these FG is to ensure an optimal use of power generation plants and transmission infrastructure across Europe*". This could imply:

- A widening of bidding zones – In cases with no significant network congestion within or between transmission control areas, then several control areas may be combined into one bidding area (as has been the case in Germany-Austria where 5 control areas have been combined to constitute one bidding area in the wholesale market).
- A subdivision of control areas into separate bidding zones – In case of significant congestion within a control area, this may be divided into several bidding zones, when it is not possible to cure congestion by redispatch or if the „welfare gain is higher with smaller zones".

In its recent consultation on congestion management the Agency for the Cooperation of Energy Regulators, ACER, noted that, *"(t)he CACM Network Code(s) shall ensure that, when defining the zones, the TSOs are guided by the principle of overall market efficiency (including all economic, technical and legal aspects of relevance) and the respective network structure and topology. The definition of zones shall further contribute towards correct price signals and support adequate treatment of internal congestion."* [3] Hence, ACER introduced the criterion of "Market efficiency" into the discussion.

EU Com Decision on Svenska Kraftnät[4]

Svenska Kraftnät was accused of managing bottlenecks within Sweden by intentionally reducing net transfer capacities at the border, especially to Denmark.

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2 ERGEG, *Draft Framework Guidelines on Capacity Allocation and Congestion, Management for Electricity*, 2010.

3 ACER, *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity*, Draft for Consultation, page 8, 11.April 2011.

4 European Commission, *Commission decision of 14.4.2010 relating to a proceeding under Article 102 of the Treaty on the Functioning of the European Union and Article 54 of the EEA Agreement (Case COM/39351 – Swedish Interconnectors).*

Danish energy traders had complained about this to the Commission, as a breach against the principle of free trade.

The European Commission had found the accusation of energy traders as valid. It agreed with the Swedish TSO, Svenska Kraftnät, that it has to take measures to relieve congestion without deliberately reducing net transfer capacities at the border. Svenska Kraftnät offered to apply market splitting within Sweden, by creating several bidding areas, as a congestion management method. This is in line with the market design in the Nordpool region, where market splitting is applied as one important measure for congestion management.

The main characteristics of the Svenska Kraftnät decision which has to be kept in mind are:[5]

- Svenska Kraftnät intentionally reduced net transfer capacities in order to manage congestion within Sweden; as well as
- Svenska Kraftnät offered to apply market splitting, which is in line with the Nordpool region market design.

1.3.1 CWE Market Coupling

Germany has in 2010 been integrated into the Central Western Market Coupling regime that previously already combined France, Belgium and the Netherlands.

In this context there have been discussions that

- Bidding areas should be created that are roughly comparable in size. This would necessitate a splitting of the current Germany-Austria area.
- Congestion within Germany may be relieved, by limiting transfer capacities at the German external borders (although such arguments have not been substantiated; this will be explored as part of this study).
- Power flows within Germany create loop flows on third systems that require those to lower their transfer capacities.
- The determination of transfer capacities should be undertaken flow based rather than statically. It is argued that to work efficiently, this may require the creation of smaller bidding zones.

5 We will show in later sections of this report that the Swedish case does not qualify as a template for the German-Austrian bidding area.

1.4 Scope of the study

Motivated by recent developments and the current discussions on the EC level the Bundesnetzagentur has retained Frontier Economics Ltd ("Frontier") and Consentec GmbH ("Consentec") to explore the economic merits and downsides of breaking up the joint German-Austrian bidding area into smaller zones. The study is to cover two dimensions:

- **Develop a (generic) reference framework** within which to explore quantitatively and qualitatively the creation of additional zones in any market (through market splitting);
- **Apply the generic framework to the specific situation in Germany-Austria**.

The study is also to consider the option of using Nodal pricing as a congestion management regime. The focus, however, is on the comparison of wider bidding areas or the introduction of market splitting within wider areas.

1.5 Definitions

In this report, we repeatedly refer to a number of complex technical concepts. We define some of the concepts in the following:

- **Bidding area** – A network area, within which market participants in energy trading submit their bids day ahead, intraday and in the longer term timeframes[6].
- **Price area** – Price areas are network areas with one uniform price. The price zone can consist of 1…n bidding zones. The number of price zones depends on the method for calculation of the cross-border capacities between bidding zones. In the case of NTC the number can range from 1 to n. In the case of the flow based approach the number of price zones is either one, if there is no congestion between any bidding zone, or n, corresponding to the number of bidding zones.
- **Market splitting** – Market splitting is here defined by splitting one bidding zone in two or more bidding zones.[7]

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6 This definition corresponds with the definition in: ERGEG, *Draft Framework Guidelines on Capacity Allocation and Congestion, Management for Electricity*, 2010.

7 Hence we use the term to denote the structural decision on the resolution of bidding areas. This needs to be distinguished from the meaning that "market splitting" has, for instance, in the Nordic countries. There, it refers to an operational day ahead market structure where in a fixed setting of bidding areas the market outcome may, on an hourly basis, lead to a single price in the entire region

- **Redispatch** – Redispatch means that the TSOs instructs particular generators – whose power injection contribute to the congestion – to generate less power than planned. At the same time other generators – whose generation relieves congestion – are instructed to generate more power such that the power balance remains unaffected. The selection of generators for redispatching is on the one hand based on their location in the network and on the other hand either on their cost (where the adequacy of costs is reviewed periodically; so-called cost-based redispatch[8]) or on prices (based on bids submitted by the generation companies; so-called market-based redispatch).

- **Countertrading** – Countertrading means that the TSOs act on short-term markets in order to buy and sell power in bidding areas such that the corresponding inter-area power exchange relieves congestion. In contrast to redispatching, countertrading is a zonal activity (although the bidding areas may be smaller than those of the regular, e.g. day-ahead, market).

1.6 Approach and Structure of the report

The remainder of this study is structured as follows:

- Section 2.2 considers the recent and current congestion situation on the German grid;

- Section 2.3 and 2.4 discusses the current market situation in the bidding area Germany-Austria;

- Section 3 outlines a framework to analyse and evaluate a possible move to market splitting;

- Section 4 applies the framework developed in the previous section to the situation in Germany-Austria;

- Section 5 briefly discusses other options, namely nodal pricing and enlargement of bidding areas.

(i.e. in all bidding areas) or to different prices ("split" markets) due to exhausted transmission capacities.

8 This is method currently used in Germany.

2 Current situation in the bidding area Germany-Austria

2.1 Overview

In this section we provide an overview of the current network and market situation in Germany/Austria with a special reference to the role of Germany-Austria for the European electricity market integration.

The section is organized as follows:

- **Network situation** – We analyse the current and potential future congestions in the German transmission grid.
- **Role of the German/Austrian electricity market in Europe** – We analyse the relevance of the German electricity market as a reference market for Europe.
- **Competitive situation in the German/Austrian market** – We analyse the competitive situation based on market concentration figures for Germany. We analyse to what extent the German electricity market can be classified as a competitive market.

2.2 Network situation – congestion and congestion management

In this section we analyse the congestion in Germany in three steps:

- First, we identify potential critical transmission lines, where congestion occurs relatively frequently;
- then, we discuss the sometimes stated argument, that congestion inside Germany is shifted to the borders by the TSOs; and
- finally, we discuss the role of loop flows in the German and European meshed transmission network.

2.2.1 Statistical evaluation of congestion management measures

The process

Following the first phase of discussions about internal congestion in Germany, BNetzA installed a monitoring process in 2008, the so-called "Engpassevaluierung" (congestion evaluation). In a semi-annually cycle the German TSOs provide statistical data about redispatching and countertrading

measures that were necessary to maintain system security.[9] For this study BNetzA granted us access to all data collected so far, which cover the period from April 2008 to September 2010.

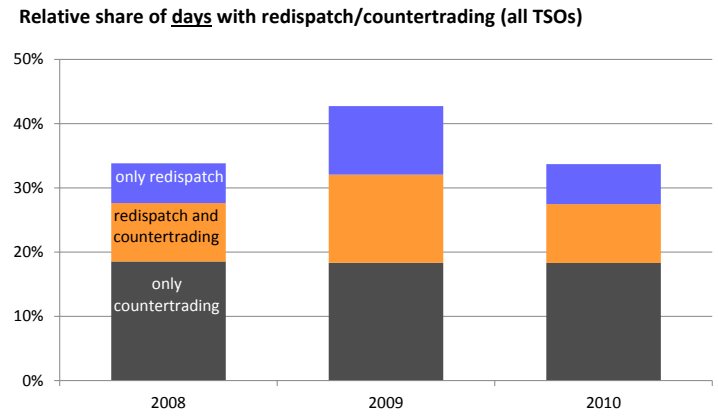
We consider the actual occurrence of severe congestion an indispensable prerequisite for any serious consideration of measures that are as significant as market splitting. Therefore, the statistical data collected by BNetzA constitute a suitable entry point into the assessment. Later on, when setting out a generalised evaluation approach, we will complement this backward looking aspect by a forward looking element (Section 3.4).

Initial evaluation

A first evaluation in daily resolution shows that during roughly one third of days either redispatch or countertrading was necessary, with only little change between the three years (**Figure 1**). A closer look at 2009, the year with the highest number of redispatch and countertrading days, reveals that congestion was almost completely concentrated in two of the four control areas, namely 50HzT and TenneT TSO (**Figure 2**).

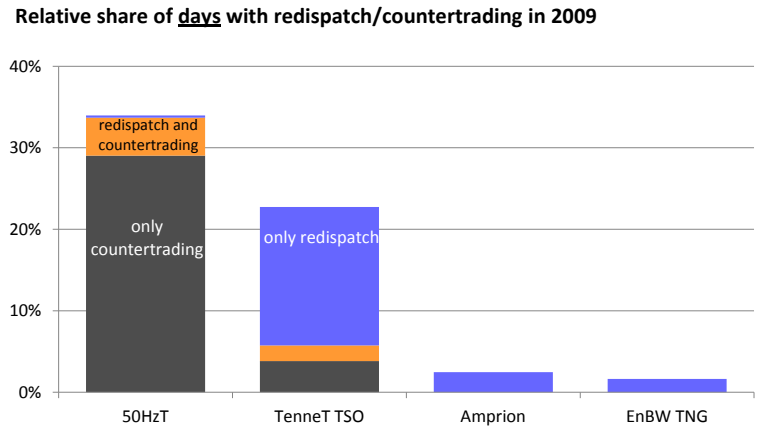
9 More precisely, these data cover so-called market based measures according to § 13 (1) clause 1 no. 2 EnWG.

Figure 1. Relative share of days with at least one hour of redispatch or countertrading executed by any German TSO



Source: TSOs

Figure 2. Relative share of days in 2009 with at least one hour of redispatch or countertrading, differentiated by TSO



Source: TSOs

Line-by-line assessment

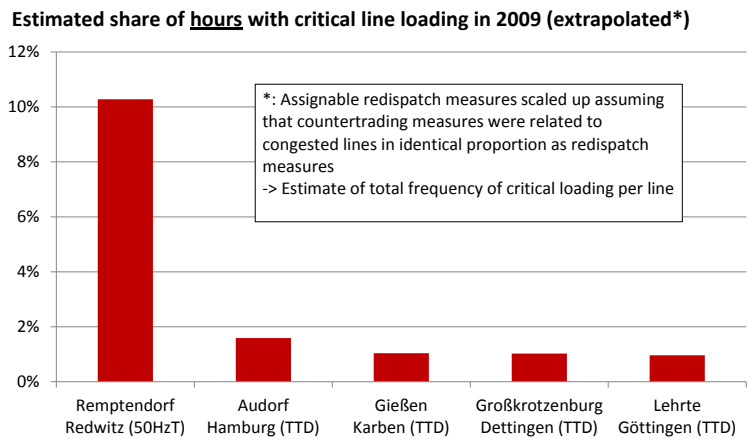
In a third step the evaluation is narrowed down to the specific transmission lines that caused the congestion management measures. Moreover, the frequency by which these lines were congested is analysed in hourly resolution. Unfortunately, the available information on the triggering events comprises only redispatch, but not countertrading measures. In order to avoid an underestimation of the frequencies of redispatch, we have scaled up the line specific redispatch

frequencies by the ratio of "total hours with either redispatch or countertrading" and "total hours with redispatch", thereby implicitly assuming that countertrading measures were related to congested lines in identical proportion as redispatch measures.

The results show that only a single line, the line between Remptendorf in Thuringia and Redwitz in Bavaria, yields a notable frequency of congestion, namely about 10% of hours in 2009. The next most frequently congested line is already below 2% of hours (**Figure 3**). This low severity of internal congestion is consistent with the latest monitoring report by BNetzA which states that total redispatch and countertrading cost in Germany amounted to 27 Mio € in 2009, which was only about 2% of the cost of ancillary services and a negligible percentage of the cost of power supply[10].

Of course, recent developments in the German generation system, especially the enforced retirement of several nuclear plants, influence the level of congestion in the system, though without changing the general assessment. Details are given within section 4.1.

Figure 3. Estimated frequency of hourly critical loading for the most frequently affected German lines



Source: TSOs, own calculations

2.2.2 Is congestion shifted to the borders?

Given the relatively vivid debate about the issue some years ago, the results presented in the previous subsection yield an unexpectedly low severity of internal congestion. Theoretically though, this low frequency of internal

10 Bundesnetzagentur, *Monitoringbericht 2010*, page 201, 2010.

congestion could have been achieved by reducing cross-border transmission capacities with the aim of protecting internal lines and lowering congestions within Germany (see below). Such shifting of congestion to the border would - in principle - be forbidden under the Congestion Management Guidelines (CM Guidelines Art. 1.7[11]) if applied on a long-term.

In the following we discuss whether such shifting of congestion could have occurred. We do this by analysing various sources of information and by conducting a numerical analysis of the network properties.

Impact of potential NTC reduction on internal congestion

The analysis in the previous subsection has shown that – up to now - only one internal German line exhibits a notable frequency of congestion. We now analyse whether the power flow on this line, Remptendorf-Redwitz, could be (or could have been) lowered by reducing any cross-border capacities (NTCs).

The effect of a power transfer between two countries or between two parts of one country on the loading of a transmission line can be expressed by so-called power transfer distribution factors (PTDFs). A PTDF denotes which share of the transfer flows on the transmission line in question. For the following assessment we determined such PTDFs using a realistic load flow model of the Continental European transmission system. This model has been composed from public data and allows for estimating the physical properties of the transmission system with sufficient accuracy. Using this model we determined exemplary PTDF values for transfers between Northern and Southern Germany and for various cross-border exchanges (**Figure 4**).

Figure 4. Absolute values of PTDF for internal German bottleneck and five tie lines with respect to internal and cross-border power transfers

	Border	DE internal	DE-FR	DE-NL	NL-BE	DE-PL	DE-CZ
	Line	Remptendorf-Redwitz	Uchtelfangen-Vigy	Rommerskirchen-Maasbracht	Geertruidenburg-Zandvliet	Hagenwerder-Mikulowa	Röhrsdorf-Hradec
Transfers	DE North<->South	**18,0%**	0,3%	1,6%	2,1%	3,0%	5,0%
	DE<->FR	0,1%	**13,2%**	7,2%	5,8%	1,1%	2,1%
	DE<->NL	0,1%	2,4%	**20,9%**	6,3%	0,4%	0,6%
	NL<->BE	0,0%	7,8%	4,2%	**18,8%**	0,4%	0,8%
	DE<->PL	3,5%	2,2%	1,5%	0,9%	**16,0%**	5,1%
	DE<->CZ	0,2%	2,3%	1,5%	1,1%	4,0%	**16,6%**

Source: Consentec

The figures show that the internal German bottleneck (Remptendorf-Redwitz) is strongly affected by power transfers from Northern to Southern Germany (PTDF of 18%). This means that redispatch and countertrading measures within

11 European Commission, *Regulation (EC) No. 714/2009 of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003.*

Germany can significantly relieve this line. By contrast, cross-border power transfers have only a very low impact on this line (red figures in **Figure 4**). For example, a reduction of the exchange from Germany to Poland by 100 MW (e.g. by reducing the NTC accordingly) would alter the flow on Remptendorf-Redwitz only by 3.5 MW. The influence of the other NTCs is even less significant.

The analysis shows that reducing any NTC for cross-border transmission would not be an effective means of limiting the flow on the only notably congested internal German line. This also implies that congestion on that line cannot realistically be shifted to a border.

For illustration purposes **Figure 4** also contains comparable figures for exemplary tie lines on the borders where cross-border transfers were modelled. One can see a similar pattern for each tie line (column): The influence of the direct cross-border transfer (e.g. DE↔NL on the tie line between DE and NL) is high whereas other transfers only have a smaller effect.

Evaluation of other available information

According to ENTSO-E rules and procedures, the NTC on a given border is the minimum of the figures obtained from the individual assessments by the two involved TSOs[12]. In mid 2010 the German TSOs prepared an evaluation for BNetzA concerning the binding limitations on each German border. The evaluation was based on data of 2009 and 2010.[13] The results show that in the large majority of cases the NTC figures in the market relevant directions were restricted by the respective foreign TSO. There are, however, two borders that deserve further attention, namely those between Germany-Denmark (West) and Germany-Sweden, respectively. The so-called "urgent market messages" issued via Nordpool[14] state from time to time that import from Denmark (West) to Germany temporarily needs to be reduced due to wind power infeed in Germany. Similar situations have been reported with respect to the Baltic Cable link between Germany and Sweden.

According to the responsible TSO, TenneT TSO, the situation on both borders is comparable, in principle. In both cases the physical location of congestion is close to the respective border. In the DE-DK case it is a transmission line from the Danish border to the Hamburg area. Import flows from Sweden partly transit through the Northern German 110 kV distribution grid, given the weak structure of the transmission grid in the vicinity of the terminal of the Baltic Cable. Furthermore, in both cases local wind generation is concentrated close to the

12 ENTSO-E, page P4-4, Standard S3.

13 We were granted permission to review this – confidential – evaluation for the purpose of this study.

14 http://umm.nordpoolspot.com/web/

border. During peak (local) wind situations the flows induced by the wind generation add to the import flows such that congestion occurs.

Theoretically, several solutions would be conceivable in order to cope with these situations, but the practical choices are much more limited:

- while network extension is planned in both cases, short-term operational measures are required to bridge the time period until these extensions are realised;
- there are no conventional power plants in Germany that contribute to the critical flows, hence redispatching is not an option. Physically, the only alternative to reduced import would be reduced local wind generation;
- given the proximity of the congested network locations to the borders, any large-scale split of the German-Austrian bidding area would not help solving the physical problem. In fact, any truly effective smaller bidding area would have to comprise only very few substations at the respective border. But then, the market would be unlikely to function in such area given its very small size and the fact that it contains only wind generation;[15] and
- consequently, the only alternative to reduce the import NTC would be to instruct a reduction of local wind infeed. This is technically feasible, but would compromise national and European targets for the support of renewables.

The above considerations show that on all German borders either the NTC is not substantially limited by the German TSOs or, as on the borders to Denmark (West) and Sweden, there is no alternative to temporary NTC limitation that would be market based and not compromise national and European renewables targets.

It should also be noted that the German TSOs perform corrective congestion management measures in order to avoid limitations for power trading, be it internal or across borders. In addition to redispatch and countertrading as discussed in Section 2.2.1, there are numerous days with so-called network related measures, e.g. change of the switching status in substations in order to improve the distribution of power flows (**Table 1**).[16]

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15 Also in the case of splitting up Sweden into four bidding areas, the inability of market functioning in too small bidding areas was acknowledged as a limitation, leading to an exception where reduction of cross-border transmission capacity was accepted as a means to manage internal congestion close to the border (European Commission (2010)).

16 More precisely, measures according to § 13 (1) clause 1 no. 1 EnWG.

Table 1. Number of days per year with network related congestion management measures

	2008	2009	2010
50HzT	141	165	129
TenneT TSO	178	213	229

Source: TSOs, own calculations

2.2.3 The role of loop flows

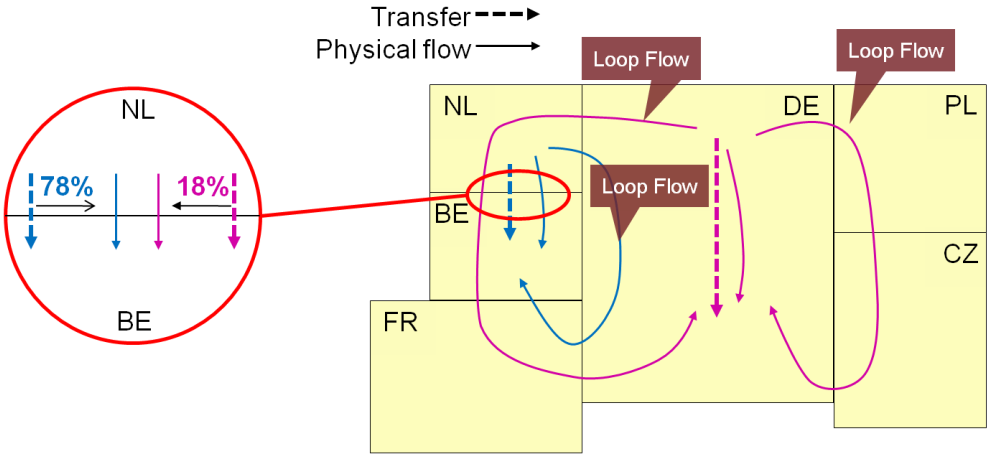
Loop flows do not constitute a reason for altering the size of bidding areas

In meshed power networks a power transfer does not only cause a physical power flow on the direct or shortest connection between source and sink, but also on practically all other network elements. The magnitude of these "loop flows" (sometimes more precisely called "parallel flows") depends on the physical properties of the network, but generally drops with increasing distance from the direct source-sink connection.

Figure 5 illustrates the phenomenon. A power transfer from Northern to Southern Germany creates flows inside Germany, but it also causes loop flows through the neighbouring countries in the West and the East. For example, about 18% of the transferred power flows through the Netherlands, Belgium and France. But loop flows are also created by cross-border power transfers. For example, only 78% of exchanges between the Netherlands and Belgium flow through the direct border between these countries. The remaining 22% form a loop flow through Germany and France, entering Belgium from the South.

These examples underpin the symmetrical nature of the loop flow phenomenon. While power transfers within Germany partly "use" foreign network regions, German transmission lines host power flows that are induced by transfers within and between foreign countries.

Figure 5. Examples of loop flows due to power transfers within and between bidding areas[17]



Source: Consentec

The fact that power transfers inside a bidding area lead to loop flows is sometimes used as an argument for splitting up that area. However, the examples above show that loop flows are created by internal as well as cross-border power transfers.

Moreover, the occurrence of loop flows is not related to the existence of congestion. The ratio by which flows are shared among the various lines between source and sink of a power transfer only depends on the so-called impedance of the lines, but neither on their capacity nor on their actual loading. For example,

- assuming that all internal German lines would transport only very low flows prior to the North-to-South transfer simulated in Figure 5, the loop flows through the Netherlands would amount to 18%; and
- assuming that some internal German lines would already be overloaded prior to that North-to-South transfer, these loop flows would still amount to 18% of the additional transfer. Flows are not "deviated" when transmission lines are overloaded.

Hence, the magnitude of the loop flows due to internal transfer in Germany is independent of the question whether the direct flow through Germany leads to overloading of a line. Rather, internal congestion management measures such as redispatch and countertrading help limiting the loop flows because they induce counter flows in foreign networks (i.e. loop flows in opposite direction) as well.

17 PTDF values based on realistic approximation, cf. footnote 9.

In addition to these technical aspects, loop flows are also legally accepted according to the relevant Regulation (EC) No 714/2009[18]. Firstly, Art. 13 (1) and (2) specify that the purpose of the inter-TSO compensation mechanism is, *inter alia*, to compensate TSOs for hosting loop flows. And secondly, the CM Guidelines[19] demand in Art. 3.5 (a) and (b) "to deal efficiently with […] loop flows".

To summarise, loop flows are technically inevitable, they occur irrespectively of the existence of congestion, and they need to be accepted according to EU law. Consequently, the occurrence of loop flows does not constitute a reason for altering the size of bidding areas.

More dynamic consideration of loop flows can increase cross-border exchanges

Nevertheless, it appears possible to increase the level of cross-border exchanges by means of more comprehensive consideration of loop flows during NTC assessment within the current bidding areas. This approach is outlined in the following.

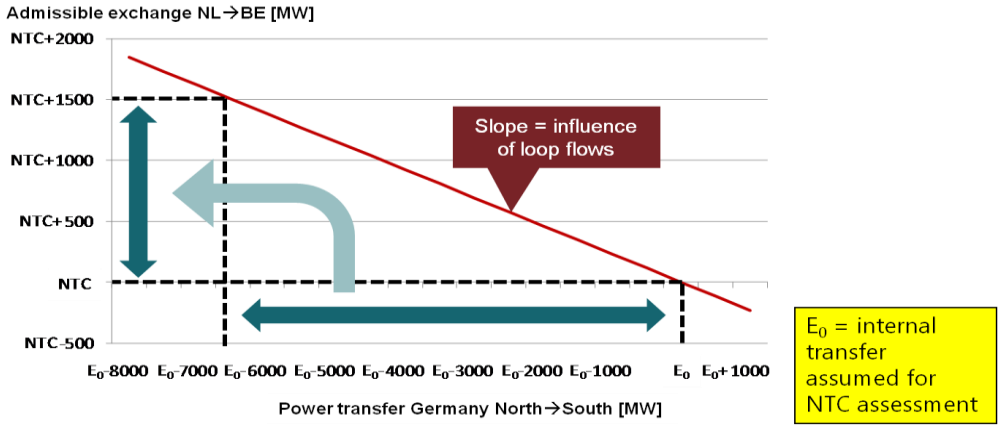
According to the example in **Figure 5** 18% of the power transfer from Northern to Southern Germany occurs as loop flow on the Dutch-Belgian border. Hence each reduction of the internal German transfer would allow for some increase of cross-border exchange from the Netherlands to Belgium – albeit only with a ratio of roughly 1:4, because the exchange NL→BE utilises the Dutch-Belgian border by 78%, i.e. approximately four times stronger than the German exchange. This relation between the internal German and the cross-border NL→BE power transfer is depicted by the red line in **Figure 6**.

18 European Commission, *Regulation (EC) No. 714/2009 of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003*, Official Journal of the European Union, 14.8.2009.

19 European Commission, *Guidelines on the management and allocation of available transfer capacity of interconnections between national systems, Annex 1 to Regulation (EC) No. 714/2009 of 13 July 2009*, Official Journal of the European Union, 14.8.2009.

Current situation in the bidding area Germany-Austria

Figure 6. Repercussion of internal German North-South power transfer on admissible exchange NL→BE



Source: Consentec

When calculating NTCs, the TSOs often assume a fixed scenario of network utilisation, on top of which the admissible magnitude of the exchange in question (here: NL→BE) is determined. This scenario includes assumptions on the geographical distribution of load and generation in each bidding area and thus on their internal power transfers. **Figure 6** mirrors this: The assumed internal German power transfer E_0 yields the NTC value for exchange NL→BE. If E_0 is static it is logical that it will be relatively high in order to guarantee a high level of network security. But the downside of this prudence is a relatively low (static) NTC.

The chart also shows that a better knowledge of the actual internal German power transfer would allow the TSOs to temporarily admit a higher exchange NL→BE. For example, the NTC could be increased by 1,000 MW if one knew in advance that the internal German transfer would be 4,000 MW lower than E_0. Such estimate could be made on the basis of the (e.g. day-ahead) wind forecast. Of course this forecast cannot be directly transformed into the expected transfer from Northern to Southern Germany, because it is of limited accuracy and the reaction of the power market to the wind infeed (and other influences) is uncertain. But nevertheless, the wind forecast could be used as an important input obtaining more dynamic assumptions on the internal German power transfer. Since this would translate into more dynamic (assumed) loop flows, the admissible cross-border exchanges of affected borders would also become more dynamic. In the case of the exchange direction NL→BE the NTC would become higher during times of low wind forecasts.

The current rules for coordinated NTC assessment in Central West Europe already allow for some reaction to the dynamic wind infeed. However, it seems[20] that the base figures (i.e. maximum NTCs) are already based on a certain level of wind infeed and corresponding loop flows, such that higher capacities could be possible in favourable wind situations. It is worthwhile to note that the planned transition to flow-based allocation (FBA) will entirely solve this problem, because the planned concept for flow-based capacity calculation is based on a network model that is updated every day and allows to fully reflect the most recent wind forecast.

2.2.4 Conclusion on network situation

Our analysis of the present situation of network congestion in Germany yields only one internal transmission line with significant frequency of congestion. Apparently the increase of network loading that was expected some years ago has been delayed because of delayed offshore wind projects, the abandonment of conventional power plant projects in Northern Germany and the standstill of two nuclear power plants due to technical problems.

Also we have not found any evidence that internal congestions have been or could be shifted to the country borders. In this respect the situation differs considerably from the one in Sweden, where the decision on national market splitting was based on the obvious shifting of internal congestion to the borders.

Since any change of the structure of bidding areas would require a certain lead time it is necessary to estimate how the present situation of network congestion may develop:

- The amount of renewable generation will continue to grow significantly. In particular, the further increase of installed wind power will create additional transport demand. (By contrast, solar power is focused in the South of the Germany and, therefore, less critical for transmission system utilisation.) Consequently, the network situation may be aggravated in the next years, and the effort and cost to maintain network security could significantly increase.
- This aggravation can be avoided by accelerated network extension. The German TSOs are striving to construct numerous new lines, and political support for grid investments has grown recently as more and more stakeholders realise its importance for achieving the renewable generation targets. . In July 2011 the "Netzausbaubeschleunigungsgesetz" (NABEG, acceleration of network

[20] We conclude this from a comparison we performed between published figures of NTC and day-ahead wind forecast.

Current situation in the bidding area Germany-Austria

extension act)[21] has come into force with the primary goal to facilitate the realisation of network projects, e.g. by assigning to BNetzA the responsibility for crucial parts of the authorisation procedures that previously had been organised in a more decentralised manner. The general expectation is that the NABEG has the potential to improve the efficiency and transparency of transmission network expansion.

Furthermore we have shown that the occurrence of loop flows does not constitute a reason for altering the size of bidding areas. Nevertheless, a more dynamic consideration of expected loop flows during the (daily or intraday) NTC assessment could help increasing cross-border transmission capacities at times of low wind power infeed. This is something that can be achieved without splitting up bidding areas.

2.3 Role of the German/Austrian electricity market for the European market

The German/Austrian electricity market is of significant relevance for the integrated European electricity market due to its

- geographic location in the centre of Europe;
- size; and its
- wholesale market liquidity.

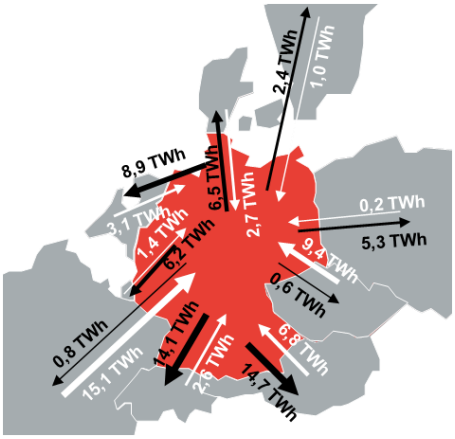
In the following, we explain these aspects in more detail.

2.3.1 Geographic location

The geographic location in the centre of Europe gives Germany a significant strategic position in the European electricity market. Substantial electricity flows are going into, out of and through Germany (**Figure 7**).

[21] Draft available at http://www.bmwi.de/BMWi/Redaktion/PDF/E/energie-gesetzentwurf-massnahmen-zur-beschleunigung-netzausbau, which was adopted by the Bundesrat (second chamber of German parliament) with minor changes on 8 July 2011.

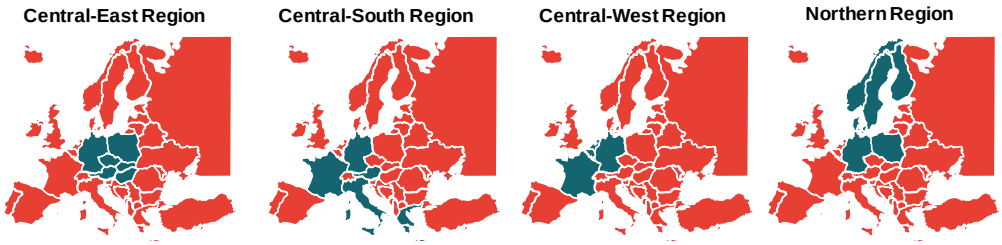
Figure 7. Import-Export Germany in 2010



Source: ENTSO-E

The important role is reflected in the deep involvement of Germany in European initiatives fostering an integrated electricity market. In a strategy paper in 2004[22] the European Commission mentioned regional markets as a step towards a pan-European market. In 2006 the Electricity Regional Initiative (ERI) has been started by the European regulators in ERGEG (a European body of independent regulators acting as an advisory group to the Commission), structuring Europe in seven (later eight) regions. The aim of the ERI is to speed up the integration of Europe's national electricity markets into a European market by removing national borders between member states. Germany is a member of four regions.

Figure 8. Electricity Regional Initiative involving Germany



Source: ENTSO-E

With the implementation of market coupling in various regions the Electricity Regional Initiatives are beginning to bear fruit:

22 European Commission, *Medium term vision for the internal electricity market*, 2004.

Current situation in the bidding area Germany-Austria

- Trilateral market coupling between France, Belgium, and the Netherlands started in 2006.
- Market coupling between Spain and Portugal in 2007.
- Market coupling between the Czech Republic and Slovakia in 2009.
- In 2009 the market coupling of the German and Nordic spot market, precisely Nord Pool Spot for DK West (DK1) incl. DK East, was launched. The market coupling is governed by European Market Coupling Company (EMCC).
- In May 2010 the Baltic Cable was included in the market Coupling via EMCC.
- In November 2010 CWE market coupling of the region "Central Western Europe" (CWE) covering France, Belgium, the Netherlands, Germany and Austria started thereby replacing the Trilateral market coupling.
- Additionally, CWE is coupled with the Nordic market, leading to a large set of coupled bidding areas in Europe (**Figure 9**).[23]

23 The advent of market coupling has generally been followed by higher price convergence and better utilisation of cross-border transmission capacities. Nevertheless, regional differences in prices are likely to remain due to limited transmission capacities between countries, differences in the generation mix, and unexpected events. However, there are also examples of perfect price convergence resulting from market coupling, e.g. the Czech Republic and Slovakia. For a further discussion see: CERA, *One Price Fits All? The Effect of Market Coupling on European Power Price Convergence*, 2010.

Figure 9. CWE and Nordic coupling

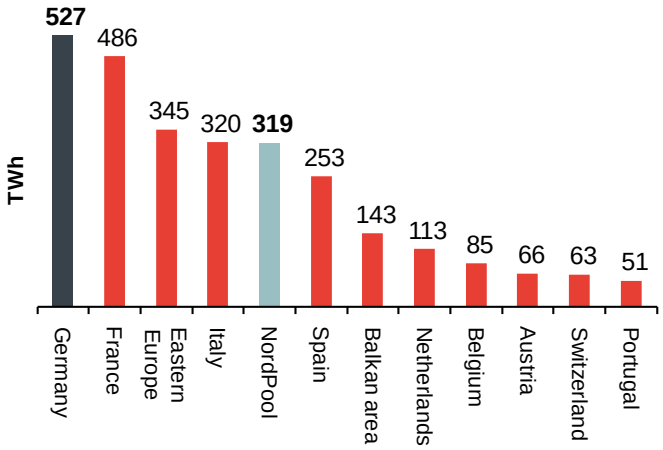
Source: Frontier Economics

2.3.2 Size of the German/Austrian electricity market

Beyond its geographic location the size of the German electricity market magnifies its strategic importance in the European integration process. Based on electricity demand Germany is the biggest market in Europe, followed by France and Italy. In comparison to France and Italy the German market is less concentrated and the liberalisation process started earlier.

Current situation in the bidding area Germany-Austria

Figure 10. Electricity demand (TWh) in 2009



Source: ENTSO-E, CERA

The size of the market and the history of liberalisation since 2001 were the basis for the development of important market institutions and the liquid wholesale market.

2.3.3 Wholesale market liquidity

Market liquidity is often measured by

- trading volume;
- number of market participants; and
- depth of the market – development of derivative products.

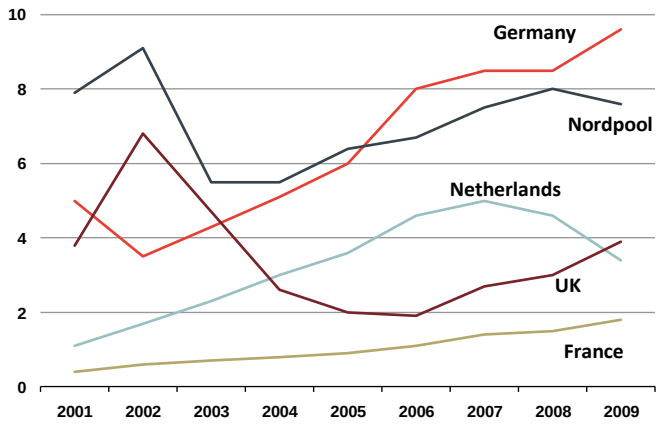
Trading volumes (spot)

The European Energy Exchange (EEX), located in Leipzig and founded in 2002, turned out to be the relevant wholesale power exchange for Germany and Austria. In 2009 the EEX launched a cooperation with the French Powernext.[24] The power exchange currently covers three bidding areas: Germany/Austria, France and Switzerland.

Today, Germany is the most liquid market place in Europe when considering churn rates: Today, the churn rate in the German wholesale power market is higher than in all other important markets in Europe (**Figure 11**).

24 The forward market was bundled in EEX, and the spot market in EPEX.

Figure 11. Comparison of churn rates for European countries



Churn rate = volume of traded products / annual demand

Source: Ofgem

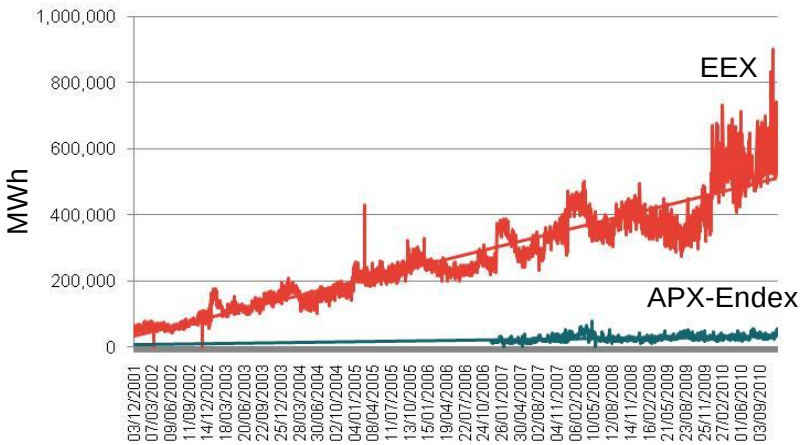
The churn rate in Germany has exceeded that of the NordPool area since 2006, while the Netherlands faced a reduction since 2007. In the UK the churn rate was high until 2002. In 2002 it was hit by the bankruptcy of the energy trader Enron. Since then the churn rate and the market liquidity has not recovered to previous levels. The low churn rate in France results from the high market concentration dominated by EdF.

UK is a good example for the sensitivity of market liquidity to external shocks and shows how rapidly market liquidity can deteriorate. The UK regulator OFGEM used the German wholesale market as a best practice example in a report on improving market liquidity[25].

One driver of wholesale market liquidity in Germany is the size of the volume of underlying physical demand in Germany which brings together many market participants. This is reflected in the growth of traded volumes at the EEX as compared to the APX-Endex exchange in the Netherlands. EEX saw a much higher growth than APX-Endex, which tends to be quite stable (**Figure 12**).

25 OFGEM, *Liquidity in the GB wholesale energy markets*, 2009.

Figure 12. EEX and APX-Endex (Netherlands) Spot volumes (2001-2010)

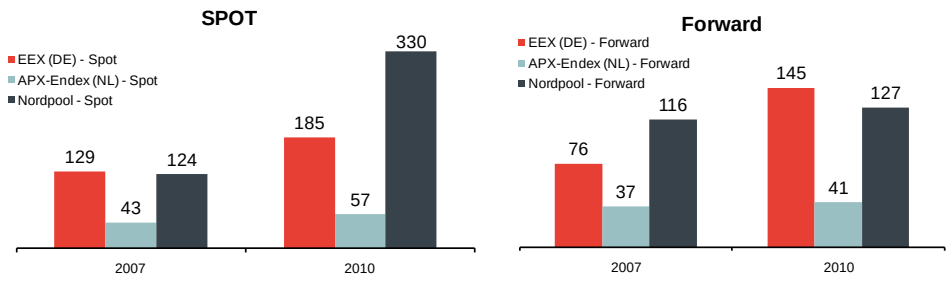


Source: Energate

Market participants

The growth of EEX is also reflected in the number of market participants. In the spot market the number has grown from 129 (2007) to 185 (2010). A steep increase can be observed for the forward market between 2007 and 2010 from 76 to 145, where the figure in 2010 exceeds NordPool. Further, the number of banks and financial institutions as market participants at EEX and NordPool increased between 2007 and 2010 bringing additional liquidity into the market. Meanwhile, APX-Endex faced a reduction.

Figure 13. Market participants at the Spot and Forward market for EEX, APX-Endex and NordPool



Source: BNetzA, OFGEM

Development of Forward market

A further indicator of the currently high market liquidity in Germany is the development of forward and index linked contracts. The liquidity in the electricity spot market spilled over into the forward market and increased the depth of the market. Currently, there are liquid forward products up to three years ahead at the EEX. In 2010 the EEX introduced a 6-year ahead peak product.

Importance of EEX as a reference for other countries

Due to the development of EEX since 2002 the PHELIX[26] became the accepted reference price for Germany and Austria. It is commonly used as the price index in OTC and bilateral contracts in Germany and Austria. Beyond that, it is the reference price for the VIK-Index, KWK-Index, market price calculations by E-Control, ÖSPI (electricity price index for Austria), and bank certificates, e.g. Barclays' WGZ-Rohstoff Garant-Zertifikat 9.

Furthermore, the impact of the PHELIX is not geographically limited to Germany and Austria. Contract parties in countries with no reliable wholesale price use the PHELIX as the reference price in the respective price formulas. Interviews with energy traders in the course of the study indicate a geographical coverage from Eastern Europe to the Balkan area. Because of the liquidity in the EEX forward market more French and Dutch market participants hedge their national contracts with EEX forward products with Germany-Austria as the place of delivery.

2.4 Competition situation

The competition situation in the German market is currently under review by the Competition Authority, Bundeskartellamt (BKartellA). The Authority has published its initial report[27] and concluded that the market is concentrated. In its report the authority presumes that several large players are individually dominant, although no evidence has been found of abusive behaviour. While the precise results are disputed and the final conclusions are yet to be published, a number of general conclusions can still be considered:

- any measures that increase market concentration in Germany would be problematic; and
- recent developments imply a reduction in market concentration.

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26 PHELIX stands for Physical Electricity Index and is the daily price index calculated by EEX based on spot base and peak prices.

27 Bundeskartellamt, *Sektoruntersuchung Stromerzeugung Stromgroßhandel, Bericht gemäß § 32e Abs. 3 GWB*, Januar 2011.

In a recent study Frontier Economics (2010)[28] found that market concentration in the German electricity market has declined significantly since 2003. This development was driven mainly by the following factors:

- **New entrants** – Since 2003 new companies entered the generation market. Thus, for example the Norwegian Statkraft and the French GDF-Suez built and took over generation assets, with Spanish Iberdrola and Danish DONG following. An increasing number of German municipalities and regional electricity companies are building up their own generation capacities, e.g. Trianel.

- **Disinvestments** – Due to an agreement with the EU Commission and a strategic realignment, E.ON sold a substantial part of their German electricity business to third parties. Examples in this context are the sale of 5 GW generation capacities (about 25% of E.ON's installed capacities in Germany), of the holding company E.ON Thüga, and of its transmission network to TenneT.

- **Investments in Renewables** – Simultaneously, a massive increase in electricity production from renewable energy, especially wind and solar power, took place. This increase was mostly driven by small and medium sized companies, so far. Hence, there were a substantial number of new entrants in this market.

According to Frontier Economics (2010), market shares for the two biggest German energy companies (CR2) have fallen from 50% to approximately 40% in 2010. Extending the time horizon of the analysis to 2012, CR2 declines further to 34% (**Figure 14**). This implies that concentration ratios CR1, CR2 and CR4 are below critical German competition law, GWB, concentration ratios (of 33%, 50% and 67% respectively). Including Austria into the relevant geographical market, which appears plausible given that Germany and Austria form a unified bidding area, has a further damping effect on market shares.

Future market trends, increase in renewable power generation, retirement of old coal and lignite plants and nuclear power plant, indicate a further decline of the market concentration in the German electricity market.

28 Frontier Economics, *Marktkonzentration im deutschen Stromerzeugungsmarkt*, Studie für E.ON, 2010.

Figure 14. Market concentration Germany

Analysejahr (Quelle)	Market area	CR1	CR2	CR4
2009 (BKartA)	Germany	31%	52%	82%
2008 (Frontier)	Germany	26% ✓	42% ✓	62% ✓
2010 (Frontier)	Germany	24% ✓	38% ✓	58% ✓
2012 (Frontier)	Germany	21% ✓	34% ✓	56% ✓

Quelle: Frontier (2010), Bundeskartellamt (2011)

Critical concentration rates according to GWB (German competition law): CR1=30%; CR2/3=50%; CR4/5=66%; Not critical concentration rates are marked with green signs.

Source: Frontier Economics (2010), Bundeskartellamt (2011)

Nevertheless, the German (BKartA, 2011) still has concerns on the competitiveness of the German generation market especially due to the high CR4 figure (**Figure 14**).[29] The concentration ratios calculated by the BKartA are higher than the numbers calculated by Frontier Economics (2010). The main reasons for the differences are differences in the definition of the relevant product market and the underlying data: For example, whereas Frontier included generation from renewable energies in the relevant product market, the BKartA excluded renewable power generation.

However, even though the BKartA assesses the market structure in the German wholesale power market still to be problematic, it did not find any proof of an abuse of market power for the recent years based on extended data collected from the industry. Nevertheless, the BKartA will keep observing the competitive situation in the market.

2.5 Conclusions

The main findings for the current situation in the bidding area Germany-Austria can be summarised as follows:

- **Network situation** – Our analysis of the present situation of network congestion in Germany yields only one internal transmission line with significant frequency of congestion. Also we have not found any evidence that internal congestions have been or could be shifted to the country borders in any significant way. We have shown that the occurrence of loop flows does not constitute a reason for altering the size of bidding areas. Furthermore, a more dynamic consideration of expected loop flows during

29 The Bundeskartellamt uses 2009 figures for their analysis.

the (daily or intraday) NTC assessment could help increasing cross-border transmission capacities at times of low wind power infeed.

- **Strategic position of Germany in the European electricity market** – The geographic location in the centre of Europe gives Germany a significant strategic position in the European electricity market. This is reflected by the participation of Germany in four Electricity Regional Initiative and market coupling initiatives.

- **Size of the market and market liquidity** – The size of the market was the basis for the development of important market institutions and the liquid wholesale market. The German EEX turned out to be the most liquid electricity power exchange in Europe, where the PHELIX is used by market participants within and outside Germany as an important reference price.

- **Competition** – Although, the market concentration in the German electricity market decreased since liberalisation the German Competition Authority, Bundeskartellamt, assesses the market structure in the German wholesale power market still to be problematic, although it did not find any proof of an abuse of market power for the recent years based on extended data collected from the industry. Nevertheless, the BKartA will keep observing the competitive situation in the market.

3 Market splitting – generalised evaluation approach

In this section we develop a framework for evaluating the technical and economic effect of a possible market splitting of existing bidding areas.

This discussion is driven by the current European debate on Congestion Management, according to which "*several zones are possible in case of structural congestion within the control areas, which cannot be solved by methods of countertrade / redispatch or where the welfare gain is higher with smaller zones.*"[30] Currently, there is an ongoing discussion if the bidding zone Germany-Austria exhibits conditions of *structural congestion* and *welfare gains* in the case of splitting up the bidding zone.

ERGEG (2010) does not define exhaustively what is meant by:

- structural congestion; and
- welfare gains.

In its recent consultation on congestion management ACER noted that, *"(t)he CACM Network Code(s) shall ensure that, when defining the zones, the TSOs are guided by the principle of overall market efficiency (including all economic, technical and legal aspects of relevance) and the respective network structure and topology. The definition of zones shall further contribute towards correct price signals and support adequate treatment of internal congestion."*[31] Hence, ACER introduced the criterion of "Market efficiency" into the discussion.

In the following and based on our definition for structural congestion we develop a generalised sequential approach for evaluating the technical and economic effects of splitting a bidding area into several bidding areas.

The section is structured as follows:

- In Section 3.1 we discuss options for dealing with structural congestion in a wider perspective and place market splitting as one of several options to cope with congestion in this environment.
- In Section 3.2 we summarize arguments in favour and against market splitting which we collected from interviews with main stakeholders in the market.

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30 ERGEG, *Draft Framework Guidelines on Capacity Allocation and Congestion Management for Electricity*, page 8, 2010; Further see: ERGEG, *Draft Framework Guidelines on Capacity Allocation and Congestion Management for Electricity – Initial Impact Assessment*, 2010.

31 ACER, *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity*, Draft for Consultation, page 8, 11.April 2011.

- In Section 3.3 we describe the steps of our generalised sequential approach for evaluating market splitting.
- In Section 3.4 we introduce our definition of "structural congestion".
- In Section 3.5 we discuss the technical effects of market splitting on cross-border capacities.
- In Section 3.6 we introduce the economic assessment of market splitting based on economic efficiency.

3.1 Options for Dealing with Congestion

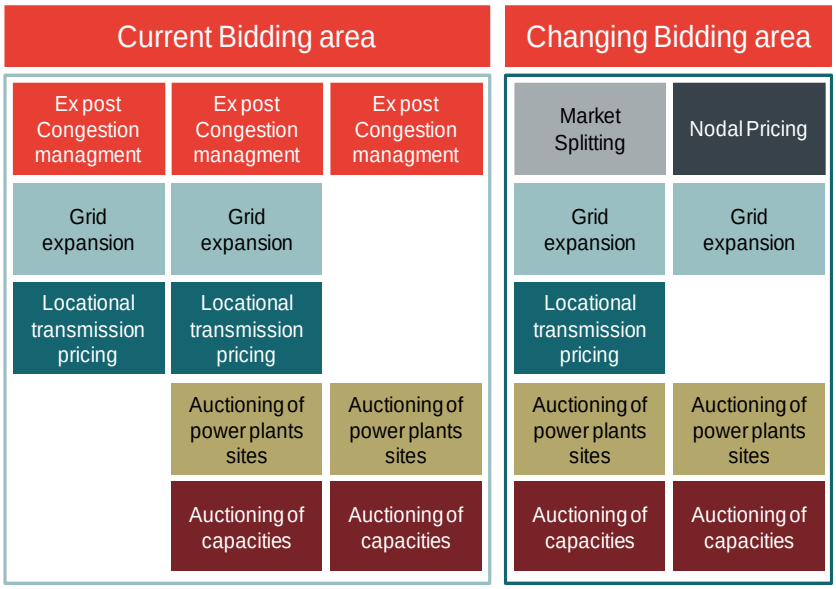
Before discussing market splitting as a means to cope with congestion in more detail, it is worth noting that market splitting is just one of many options to deal with congestion. As already outline in Section 1.2 principle options include

- Measures that fundamentally relieve congestion include:
  - Grid investment and reinforcement;
  - Management of the location of new power stations and loads
    - *Locational transmission pricing* – locational pricing can send locational signals to generators and demand, thus, relieving congestion by locational decisions, where to invest;[32]
    - *Auctioning of power plants sites* – the auction of sites can send locational signals to generators, where to locate their plants.
- Measures that have a more short term and operation effect include:
  - The market based control of injections and loads e.g. by market splitting (e.g. splitting wider market areas into smaller zones within which no congestion arises) or nodal pricing;
  - Redispatching power stations close to real-time.

Some of the options can be combined and some can be applied without changing the size of the bidding area. Hence, they can supplement the existing congestion management measures (**Figure 15**).

32 Locational transmission pricing leaves the uniform energy price unaffected. The locational difference only covers the transmission network tariffs.

Figure 15. Options for Dealing with congestion (example for possibly mix of instruments, not exhaustive)



Source: Frontier Economics/Consentec

However, before splitting an established bidding area it is necessary to analyse, if the expected benefits from market splitting, e.g. locational signals for investment decisions for generators and/or load, can be achieved by measures within a given bidding area.[33]

3.2 Main arguments in favour and against market splitting

In the course of the study, we interviewed market participants in order to get an overview of the main arguments used in the practical debate in favour and against a potential split of the German/Austria bidding area into two or more bidding areas.

We used the results from the interviews in two ways:

- as a guideline for structuring the catalogue of criteria to evaluate a potential market split; and
- to check the completeness of a catalogue that we have developed independent of the interviews.

[33] We think, that this is an important aspect in the application of the sequential framework and discuss this aspect in more detail in Section 4 on the application on the bidding area Germany-Austria.

The main arguments *pro* and *con* market splitting can be grouped according to **Table 2.** One often mentioned argument in favour of market splitting, and in its extreme form nodal pricing, is that the market sends the right locational signals to mitigate or eliminate congestion by power plant investments or relocation of power demand. The impact on market concentration and market liquidity were the frequently arguments mentioned against market splitting and smaller bidding areas.

We present the arguments here in an uncommented manner. In the following section we develop which arguments we regard as justified in principle and how to integrate them into a more general evaluation approach.

Table 2. Market Splitting – arguments pro and con

	Pros	Cons
Efficiency	Locational signals for power plant investments Better control of load flows Reduction of „security margins“ for cross-border capacities Market-oriented Congestion management	Higher price volatility reduces planning security Lower incentives for grid investments Impact on load flow in case of Renewable priority net access not clear
Competition and Market Concentration	Making market power in redispatch market transparent Regulation and/or market monitoring can avoid abuse of market power in day-ahead market	Increase of market concentration Market concentration in Day-ahead market has a feedback on forward market Higher complexity impacts retail market
Market Liquidity	Financial traders can benefit from specific know-how in other respective regimes that use market splitting Price differences in different bidding areas can be hedged with Contract for differences or Financial transmission rights	Hedging the new price risk caused by market splitting by vertical integration and thus reduced trading on the market Hedging with physical assets Market participants leaving the market, because impact of change in market design unclear

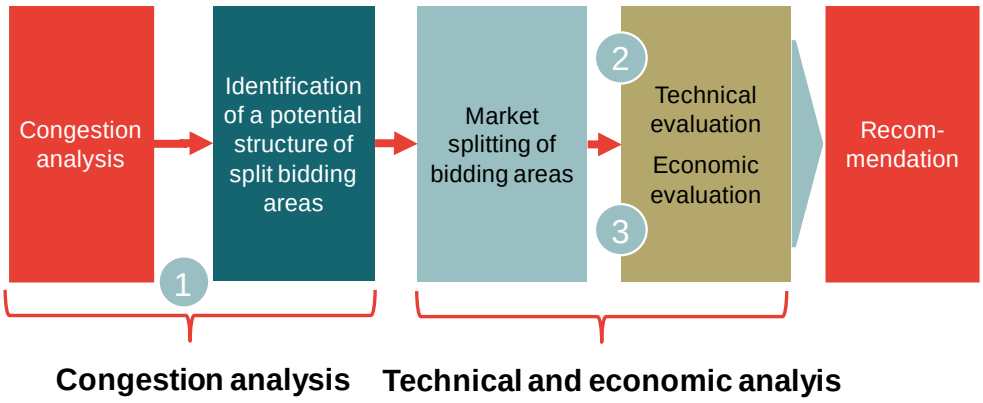
Source: Interviews with Stakeholders

Market splitting – generalised evaluation approach

3.3 Defining the framework

In this section we define a more general framework for the institutional comparison of splitting one bidding zone into several bidding zones. The analytical framework is based on three sequential steps (**Figure 16**):

Figure 16. Sequential framework



Source: Frontier Economics / Consentec

- **Step 1 – Congestion analysis:** Analysis of the current and future grid situation and identification with respect to congestion. The analysis answers two questions:
  - Does the severity of congestion inside bidding areas justify considering a potential split?
  - Where would be the right borders for potentially splitting up the market?

  Only if the first question can be answered with "yes" then the process of market splitting should be further explored. In the absence of current or prospective congestion no further action would be needed.

- **Step 2 – Technical analysis:** Even if a severe congestion is identified in the network, it has to be analysed if market splitting is a feasible and /or the best way to cope with this congestion from a technical point of view (i.e. whether market splitting could make a constructive contribution to the congestion).

- **Step 3 – Economic analysis:** If step 1 and step 2 are passed the change in market design has to be analysed from an economic perspective in step 3. This step consists of an economic cost-benefit analysis of options for a reformed market design that include market splitting.

3.4 Step 1 – Congestion analysis

As outlined above, the purpose of congestion analysis in the given context is to evaluate the occurrence of congestion and to assess whether and where it is severe enough to consider it a potential reason for the delimitation of bidding areas. This is based on the idea that spots of severe congestion should be the basis of bidding area formation (necessary condition), but ultimately a modification of the size, number or shape of bidding areas needs to be justified by overall economic superiority over the status quo (sufficient condition).

When evaluating the severity of congestion we propose to distinguish between two different time frames:

- **Structural vs. intermittent** – Clearly, when congestion occurs only sporadically it does not justify any fundamental countermeasures such as altering of bidding areas. Therefore, the first step of congestion analysis needs to assess, if congestion currently is structural, i.e. if it recurs in a high frequency and to a significant extent at the same location. A reasonable time frame of assessment would be one year as this allows for independence of seasonal effects.

- **Sustained vs. temporary** – In addition, it is necessary to assess how the current situation of congestion is expected to develop over time. Even if congestion at a certain location was structural and not only intermittent during the latest year for which respective information is available, it can happen that congestion is expected to be mitigated soon by means of network expansion or by a favourable development of the geographic distribution of generation and load. Bearing the necessary lead time for modifications of the bidding area structure as well as to the costs of transition, ignoring such medium term development could easily lead to an inappropriate economic assessment in later steps of the investigation.[34]

It is difficult to predefine a concrete and objective threshold values to distinguish between structural and intermittent and between sustained and temporary congestion. This is because on the one hand such threshold would have to consider the severity of congestion in economic terms, while the comprehensive assessment of the economic consequences of bidding area formation takes place only after the potentially relevant congested locations have been identified. Irrespectively of concrete values we propose the following guidelines to be followed:

[34] It is interesting to note that Art. 1.7 of the CM Guidelines represents a similar approach as it allows to temporarily tolerate inappropriate areas for congestion management "until a long-term solution is found".

Structural vs. intermittent congestion

In order to distinguish between structural and intermittent congestion, it appears appropriate to focus on technical indicators such as frequency or amount of congestion. We can achieve an even more relevant evaluation by additionally determining some measure of economic value in order to combine and weight the technical indicators. This could be achieved by comparing, by means of simulation, the cost of extending the network (in order to alleviate congestion) to the reduction of variable generation cost that could be obtained through such extension. However, given the complexity of this approach, a simpler evaluation of congestion frequency and/or amount may also prove sufficient in practical cases, depending on the magnitude of the respective indicators. (For example, when a line is only very rarely congested, it is unrealistic to assume that an economic simulation will classify it as anything other than intermittent.).

Temporary vs. sustained congestion

The threshold issue for distinguishing between temporary and sustained congestion is twofold.

- First one needs to make an assumption about the potential process of (cyclic) decision on and implementation of new bidding area structures. Modifying this structure only makes sense if the reasons for doing so remain valid at least until a notable portion of the minimum validity period of the new structure has passed. If congestion, even if currently considered structural, is expected to be alleviated earlier it should not constitute the basis of a new structure of bidding areas.

  For example, if one assumes that the structure of bidding areas could be changed every five years with a lead time of three years,[35] then the time horizon for assessment of congestion should encompass roughly five years from now in order to cover developments until approximately the middle of the validity period of the new structure.

- Second it is necessary to deal with the general uncertainty of future developments. Within the time period one has derived on the basis of the considerations of the previous bullet point, all developments should be taken into account that are considered sufficiently certain. Naturally, this implies an element of subjective estimation.

  This is particularly relevant with respect to assumptions on future network reinforcement, because there is some interdependency between market

[35] These assumptions are generally realistic according to Section 3.6.9.

splitting and incentives for network expansion:[36] By making too prudent assumptions on the realisation of network expansion projects one may come to the conclusion that market splitting is appropriate, and a respective decision will reduce incentives to realise the network projects – turning the assumption into a self-fulfilling prophecy. Likewise, it is risky to make too optimistic assumptions on grid development – although refraining from splitting bidding areas will keep up the pressure to implement network reinforcement projects. An analysis of external factors such as political support for network projects may prove helpful to find a balanced set of assumptions.

On the basis of the above criteria, locations of congestion should be considered as potential reasons for delimiting bidding areas only if congestion is structural and sustained, i.e. expected to remain structural for the next years. While the considerations presented above provide for some guidance as to the application of the criteria to concrete cases, the setting of threshold levels for "structural" and "sustained" will inevitably contain case specific elements.

3.5 Step 2 – Technical effect of splitting of bidding areas

As a preparatory step before checking if a new constellation of bidding areas is economically superior to the *status quo*, we recommend assessing the technical effectiveness of the considered modification. Two aspects are relevant in this respect:

- **Impact on the amount of cross-border transmission capacities** – For instance, if commercially available transmission capacity on existing borders could be increased by market splitting, this would yield additional opportunities for economically linking adjacent bidding areas.

- **Impact on the utilisation of transmission capacities** – Another question is if the market participants get better opportunities for efficient utilisation of cross-border transmission capacities. This depends on the rules for treating non market based generation in cases where the share of such generation (e.g. from renewable sources) is relevant. Note that the utilisation of transmission capacities might change even if their amounts stay the same.

The impact on the amount and utilisation of transmission capacities is the driver of some economic effects and, therefore, the technical assessment contributes to underpinning the later economic analysis.

36 See section 3.6.6 for a comprehensive discussion of this aspect.

The technical effect of market splitting strongly depends on case specific influences, such as the reasons of congestion and the geographical and network topological constellation. For further discussion of this aspect we refer to Section 4.2, where we apply the general framework on the Germany-Austria case.

3.6 Step 3 – Economic assessment

In the following we discuss the structure of the Cost-benefit analysis to assess splitting up one bidding area into two or more bidding areas to cope with *intra bidding area* structural congestion. However, we want to note two important points:

- **Market integration best facilitated by strong transmission network** – A strong transmission network is the precondition for European *market integration*. Increasing the transmission capacities integrates the European market by enhancing trade potential and competition. Expansion of transmission lines integrates generation from renewables into the European market. Re-enforced transmission grids obviously relieve congestion, i.e. the dispatch of power stations does not need to be constrained. In this context it is important to analyse the interdependency between market splitting and incentives for network expansion.

- **Market splitting not the only option** – Market splitting should not be considered as the only option to tackle the problem of structural and sustained congestion. There are various other options available for providing locational signals inside one bidding zone with a lesser impact on the existing market design than market splitting, e.g. transmission pricing can be adapted to include locational signals (see Section 3.1).[37]

3.6.1 Cost-benefit analysis

In the following, we evaluate the benefits and costs of market splitting based on the criteria „efficiency“. We differentiate between:

- *Static efficiency* – This means the electricity system should be operated on a "least cost" basis given the existing network and other infrastructure, e.g. generators should be dispatched in a manner that minimises the total system costs of meeting consumers' demands;

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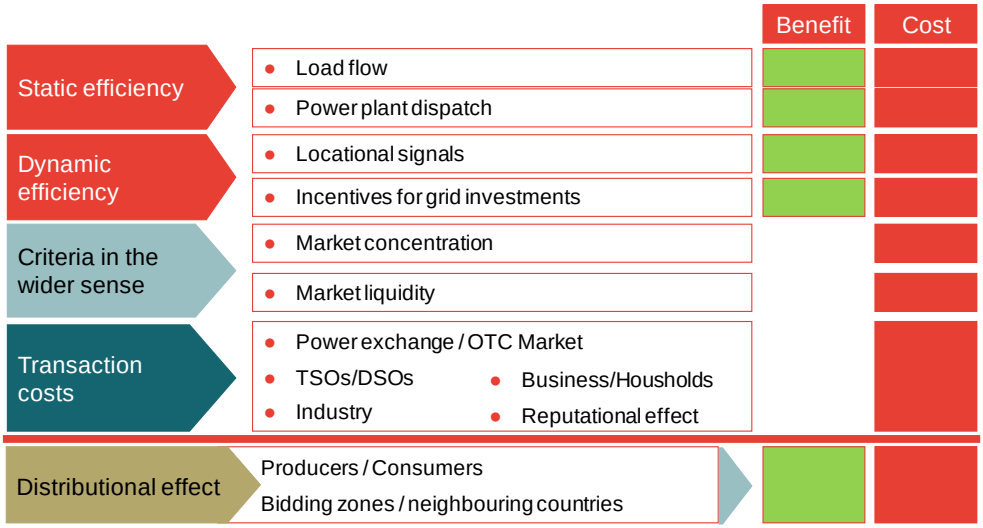
37 For an overview of different instruments for locational signals, including transmission pricing see: CESI, *Implementation of short and long term locational signals in the internal electricity market*, Report for Eurelectric, 2003. An international overview of transmission pricing methods is provided in: Frontier Economics, *International transmission pricing review*, Report for NZ Electricity Commission, 2009.

- *Dynamic efficiency* – This means that ongoing efficiency should be maximised over time; dynamic efficiency is commonly linked to the promotion of efficient longer-term investment decisions of plants, loads and transmission network.

Figure 17 shows the structure of the economic cost-benefit analysis.

Figure 17. Structure of Cost-Benefit Analysis



Source: Frontier Economics / Consentec

Benefits of market splitting are expected from more efficient generation dispatch in the short run and from locational signals for investment decisions for power plants, demand, and transmission lines in the long run.

Costs of market splitting are mainly driven by transaction costs and indirect costs. The transactions costs consist of two categories:

- *Primary measures* – costs related to the change in market designs;
- *Secondary measures* – costs resulting from the change in market design, e.g. because existing and legacy contracts need to be rewritten to comply with the new market design.

Indirect costs occur from criteria in the wider sense. Market splitting has an effect on market concentration and might result in prices not reflecting competitive levels.

Market splitting also has distributional effects on market participants. Market splitting in general creates a high- and a low-price market area. This results in distributional effects between producers and / or consumers in the two areas which might lead to political pressures and indirectly increase the transaction costs.

Market splitting – generalised evaluation approach

We explain each of these aspects in some more detail in what follows.

3.6.2 Static Efficiency – Least cost dispatch

We distinguish two types of congestion management:

- *Curative congestion management (e.g. Redispatch/Countertrading)* – In this case congestion is solved after the spot market has been cleared by altering the dispatch of power stations within a bidding area. It must be noted that curative congestion management is theoretically also possible between bidding areas, however, in this case the coordination effort for TSOs in the respective bidding areas are quite high;

- *Preventive congestion management (e.g. Market splitting)* – In this case congestion is cleared in the spot market by altering the dispatch of power stations in at least two distinct bidding areas.

For the following discussion it is helpful to distinguish situations:

  - with (local) market power; and
  - without (local) market power.

Efficiency of dispatch in principle – Without local Market Power

The extreme form of preventive area congestion management is nodal pricing, where each node is defined as one bidding area. Under the strong assumptions of perfect competition, e.g. price-taking behaviour of all agents, no market power, perfect information, nodal pricing will take complete account of the technical aspects of operating the transmission system when dispatching power plants. This could in theory result in least cost dispatch subject to the congestion constraints between all interconnected nodes. The outturn price at each node reflects generation costs, congestion costs and losses and will be equal to the marginal cost of serving one additional unit (MWh) at each node. The outcome of nodal pricing is often used as the theoretical benchmark for static efficiency.[38]

The principal difference between congestion management regimes based on market splitting and redispatch/counter trade is that

[38] However, one has to keep in mind the strong assumptions of perfect competition for this "optimal" benchmark. Weakening for example the assumption of price-taking behaviour of producers in nodal pricing, which seem to be quite reasonable – at least at certain times – has a negative effect on the "optimality" of nodal pricing.

- market splitting resolves congestions in the spot market clearing[39] whereas redispatch/counter trade solves congestion after the spot market has been cleared; and
- the two regimes result thus in different electricity prices in the spot market and thereby different economic consequences to power producers and consumers.

If redispatch is carried out optimally, including redispatch across borders, it will lead to the same final power dispatch and thereby the same overall resource utilisation as nodal pricing in the perfect competition market setting. However, with redispatch, the corrective action will not influence wholesale power prices which are uniform within the bidding area.[40.]

Accuracy of efficient plant dispatch – without Market Power

Market splitting has a drawback compared to the theoretical optimum of nodal pricing. The dispatch is unlikely to be optimal. With market splitting dispatch would be optimal only if each power plant in the affected bidding areas had the same congestion relieving effect. In this case the location of the power plant, near or far from the congested line, would have no influence on relieving congestion and the merit orders in the affected bidding areas would lead to an optimal dispatch of the power plants subject to the congestion constraint. However, it is a physical reality that there is an influence of the location of power plants on relieving congestion. Power plants near congested line tend to have a higher impact on relieving congestion. This information is not included in the merit order, when market splitting is used for congestion management.

In Frontier Economics/Consentec (2008) we evaluated the effectiveness of different congestion management systems. By effectiveness we defined the relationship between the change in the load flow by changing the market based dispatch, e.g. a change in the dispatch of one power plant by 1.000 MW changes the load flow by 150 MW (15% effectiveness). We showed that the effectiveness of congestion management decrease when deviating from a nodal, which can be organised as cost-/market-based redispatch or nodal pricing, to a zonal approach. This means that dispatch costs tends to be higher than theoretically necessary in the case of market splitting and redispatch may still be required within a bidding area when physical congestion arises.

With market splitting, dispatch is therefore less likely to be optimal.

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39 The same holds true for Nodal Pricing.

40 However, different electricity prices in the spot market will have consequences on the distribution of welfare, e.g., between producers and consumers and among bidding areas depending on how the costs for redispatch are divided. Moreover, there could be implications for long term investment signals as spot prices are different in the two regimes.

Market splitting – generalised evaluation approach

- the larger the new bidding zones are;
- the more congested lines there are; and
- the more congestions "move around" within in the grid.

The effect of Market power

If the market is not characterised by conditions of perfect competition this can have different effects on dispatch patterns in the different approaches to congestion management (single zone/redispatch, market splitting/redispatch or nodal pricing).

Curative congestion management and market power

If the market is not characterised by conditions of price-taking behaviour, the problem of market power and strategic bidding by generators may emerge. Hence, a generator may be able to gain from deviating from competitive bids in various ways.

This can be illustrated for a market setting that covers one bidding area where bids from generators are used both for the spot market and the redispatch market. In this case the optimal strategy even for a small generator may be not to bid his marginal costs. Consider an area with a physical supply deficit. A small generator, whose marginal generation costs are below both the spot price and the (higher) redispatch price, has a choice to make. If he bids his marginal costs he will be selected in the spot market, thus getting the lower of the two prices for the deficit area. If on the other hand, he correctly anticipates both prices (e.g. by understanding the marginal cost of the next unit to be dispatched instead of him) and places a generation bid in between the two, he will be remunerated according to the higher redispatch price. Hence, a generator who bids towards a spot market and subsequent redispatch market has an incentive to bid strategically above his marginal costs regardless of his capability to exert market power in a wider market. Individual market player bids will be based on their individual expectation of the market clearing prices: spot and redispatch.[41]

A way to cope with this problem of market power, e.g. currently used in Germany, is to decouple the spot and redispatch market and regulate the latter. In this case redispatch is based not on market bids but on the costs of the generators. These costs are periodically reviewed by the regulator. However, tackling strategic bidding by regulation is not without a cost. Due to the periodical review cost-oriented congestion management cannot take into account short term input price variations in fuel or CO_2 emission prices due to

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41 For a detailed discussion and the implications on welfare see: Ea Energy Analyses, Hagman Energy and COWI, *Congestion Management in the Nordic Market evaluation of different market models*, Study for the Nordic Council of Ministers, 2008.

- Information asymmetry between the regulator and the producers; and
- Time period between the periodical reviews of "cost-oriented" prices which tend to be a few months.

Hence, the least cost dispatch is not always guaranteed. Furthermore, with increased intra-congestion more and more dispatch decisions will not be based on market but on regulated interventions of the TSO distorting the market outcome.[42]

Preventive congestion management and market power

Again the advantage, that market splitting can include short term input price variations in the dispatch decisions, depends on the competitive pressure on the spot market. Reducing the size of the bidding area may have an adverse effect on market concentration (within the bidding area) increasing the profitability of strategic bidding in the spot market. For example, undertakings may physically withhold generation capacities and change the merit order in order to increase spot prices in the respective region. This means that a generation unit with higher marginal costs will set the price compared to the situation without physical withholding the unit with lower marginal costs. As a result, total system costs will increase, reducing the benefit from market splitting.

As a consequence, there is a need to cope with market power in the case of market splitting, as well, even if bidding areas are relatively large. One argument is that due to the transparency of the spot market, dominant behaviour of undertakings are easier to detect. The threat of regulation and/or inquiries by competition authorities weakens the incentives to abuse market power. However, there is one drawback of this argument. Higher market concentration on the spot market may reduce the confidence of other market participants in the outturn of the spot market and market participants may exit the spot market reducing market liquidity.

42 See: Roman Inderst und Achim Wambach, *Engpassmanagement im deutschen Stromübertragungsnetz*, Zeitschrift für Energiewirtschaft, Heft 4, page 333 ff, 2007; and: Frontier Economics/Consentec, *Methodische Fragen bei der Bewirtschaftung innerdeutscher Engpässe im Übertragungsnetz (Energie)*, Untersuchung im Auftrag der Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen, 2008.

Static Efficiency – Summing up

Because market splitting resolves congestions in the spot market clearing, it can include short term input price variations in the dispatch decisions (at least for those corrective actions which happen to be efficient, see below). This is the main advantage of market splitting compared to a cost-oriented redispatch.

However, there are two issues to consider, which may countervail this effect:

- **Market power**, which results in bids above competitive levels with adverse effects on prices and competition in the wider wholesale market;
- **Imperfect redispatch**, because technical effectiveness of changing dispatch of individual plants is not taken into account in the respective bidding areas' merit orders. This can lead to a less efficient dispatch with market splitting/redispatch than with wider bidding areas/redispatch.

3.6.3 Dynamic Efficiency – Power plant investments[43]

Differences in electricity prices in bidding areas reveal information about the scarcity of generation (and transmission) capacities. Hence, prices can exercise their main function in market economies:

- revealing information on scarcity; and
- steering the behaviour of market participants.[44]

Due to one uniform price in a bidding zone there are no locational signals to market participants by electricity prices within the bidding area. By splitting up a single bidding zone along structural grid congestions different prices will evolve in the splitted areas. Thus, higher electricity prices in the congested (generation deficit) bidding zones will give locational signals to generators to invest in this zone. As a consequence new generation capacities near the load will reduce load flows from other areas and reduce congestion.

However, whether investors can react to electricity price signals – by relocating plants - will depend on the presence of additional factors in the respective bidding area, e.g.:

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43 It is necessary to note that there is a strong link between investments into generation and transmission networks. From an electricity system perspective it is a question of coordinating generation and transmission investments, where costs for transporting the electricity must be compared with the cost of transporting primary fuels to the power plants.

44 There are good arguments that the focus should be more on appropriate investment incentives and innovation, not short-run operational efficiency, when comparing different methods of congestion management or market design.

- *The need for additional plant capacity* – locational steering will only realistically arise if there are imminent plant investment decisions. Market splitting, by itself, may not trigger a decision whether to invest at all;
- *Availability of cooling water* – e.g. coastal or river sites;
- *Grid access* – in the case of greenfield investments distance to next grid access point influences connection charge;
- *Local approval process* – support and acceptance of local authorities and population influences investment costs and planning restrictions in certain areas;
- *Greenfield vs. Brownfield* – usage of existing site brings synergies and reduces burden on approval;
- *Taxation* – e.g. tax exemptions for certain fuel types;
- *Fuel transportation cost* – e.g. proximity to harbour facilities.

In the following, we discuss two questions concerning locational signals:

- *Generation technology* – how will different technologies react to price signals?; and
- *Characteristics of electricity price* – How will market splitting change the characteristic of electricity prices?

Generation technology

Generation technologies can be differentiated into technologies which can freely choose their location and those restricted to certain locations:

- **Technologies with free location choice** – Generally the locational choice for gas- and coal-fired power plants is free due to the possibility of transporting and storing the primary fuel. From an economic perspective the location of a gas plant is most flexible, once a gas grid exists, while coal also depends on cheap coal transport and cooling water. Hence, investors can include the location of the plant into their economic optimisation problem.[45]
- **Locationally bounded technologies** – Generation from renewables (especially from wind and hydro power) and lignite is restricted to certain locations. At least, also wind and lignite could be classified as technologies with free location choice if one neglects the production costs. The transportation of lignite is possible, however, prohibitively expensive. The

[45] The same holds true for nuclear power plants, but for Germany new built nuclear power plants are irrelevant.

same holds true for a wind power plant located in an area with low wind availability, where the average total costs will more than double due to lower utilisation factors.

Electricity prices will affect investment decisions for the two types of technologies in the same way. New generation capacities will tend to be built in the high-price bidding zone. However, an investor in a gas-fired power plant has an additional degree of freedom: the choice of location. The investor in a lignite-fired power plant can only respond to electricity prices, if its site is in the high-price area.[46]

Characteristics of electricity price – Volatility of electricity prices in smaller bidding areas

Although investors can expect higher revenues in high-price bidding zones they may also face additional risks from higher price volatility that may coincide with higher prices. Generally, the price volatility is correlated with the size of the bidding area. The bigger the bidding zone the less is the impact of single power plants on the merit order. Hence, market splitting tends to increase the volatility of the market price in the high-price bidding area because the impact of one power plant in the merit order curve can become substantial. High price volatility may increase investors' risk and as a consequence their cost of capital. However, the higher price volatility will be around a higher price level increasing the baseline revenue for the investment assessment. It is a priori not straightforward to assess which effect – higher cost of capital vs. higher baseline revenues – outweigh the other.

Additionally, higher volatility may create new profit opportunities even in the low-price bidding area. In the case of a volatile generation mix, due to a high share of wind power, the chance of price spikes due to low wind availability and high demand may make flexible technologies, e.g. gas turbines, storages, more attractive even if they only operate in view hours of the year. Hence, price volatility around a low price level may further reveal information on the scarcity of certain generation technologies, e.g. flexible generation and storage.

Characteristics of electricity price – Reliability of electricity prices in smaller bidding areas

Every price signal that is to have an effect on the investment decision must be reliable in the long run. In this context shifting borders between bidding areas would create an issue for investor's planning security. A power plant located in a high price bidding area near the border to the low-price bidding area has a

46 In the unlikely case of very high electricity prices in the high-price bidding area, lignite power plants might change their location from the low-price into the high-price bidding area. But we neglect this case.

substantial downside risk, if by chance the power plant is suddenly assigned to the low-price zone. As a consequence, investors into a power plant will have to make two forecasts:

- *Price forecast* – This is the core competence of the generator;
- *Grid forecast* – Additionally the generator has to forecast in detail the future power flows in the network, the impact of its power plant on the power flows and the location of future (moving) congestions in the network determining the borders of the bidding areas. However, this is not the core competence of a generator, especially in an unbundled electricity system and when considering that the grid situation is significantly affected by investments into grid, which depend on discrete choices of TSOs, regulation, policy moves, planning procedures, etc.

Additionally, the long-term price forecast will be more difficult in smaller bidding areas.

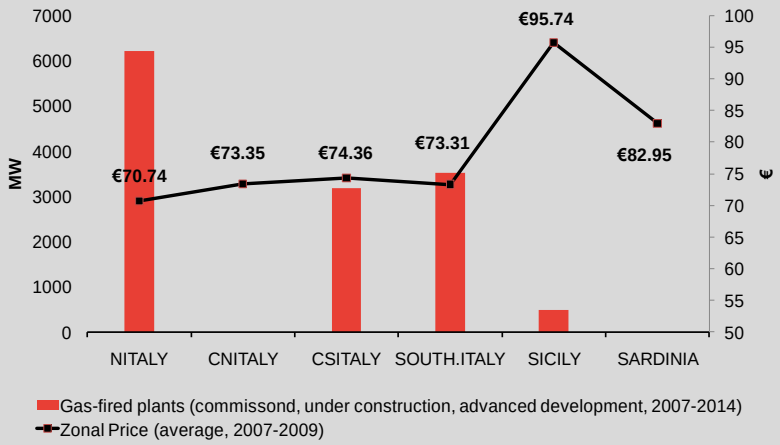
Case Study – Zonal prices in Italy – the impact of price differences

Since the beginning of liberalisation the Italian electricity market consists of six different bidding zones. Furthermore, Italy tends to be a high-price country compared to Germany, indicating a need for additional generation capacities. The price differences between bidding zones were substantial in the years 2007-2009. Especially, Sicilia (€83/MWh) and Sardinia (€96/MWh) faced higher average prices than the other zones (around €70/MWh).

We analyse the impact of price differences on locational decisions for gas-fired power plants. We focus on these power plants, because it is a technology with relatively free location choice and the majority of new built and planned conventional power plants for the period 2007-2014 are gas-fired. The impact of price differences in the six price zones on locational decisions is however not unambiguous.

Although the average electricity price for 2007-2009 for the North Italy (NItaly) price zone was the lowest most of the new built and planned gas-fired plants in 2007 to 2014 are located in this zone. North Italy is followed by Central South (CSITALYI) and South Italy (SOUTHITALY). Although prices on average were appr. 3€ higher the new built/planned gas-fired power plants were only half the amount in NItaly. The reason for low investments in Sicily and Sardinia may be that because both regions are islands, the price would have fallen by too much if plant had been built.

Figure 18. Italy Price zones – New built, under construction, advanced development gas-fired plants (2007-2014)



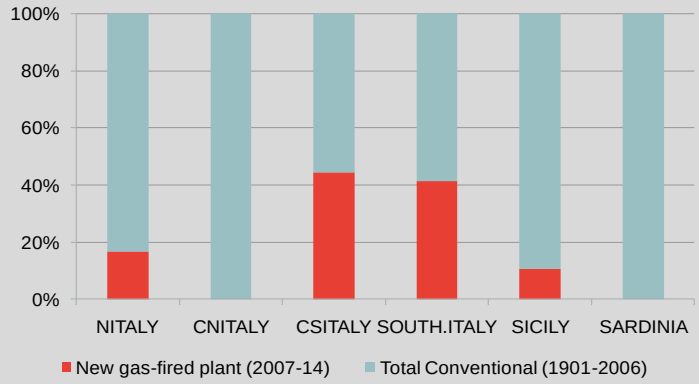
Source: Platts, Frontier Economics

However, based on the fraction between new built/planned gas-fired power plants and conventional power plants in the different zone the picture slightly changes, indicating that higher electricity prices in the CSITALY and

SOUTHITALY price zone might have positively affected investment decisions at the margin in these two zones. The share of new built/planned gas-fired power plants of total conventional (excl. renewables) generation capacities was higher than in NITALY, indicating that investments in these two price zones became more attractive.

There are obvious limitations to this simple analysis. Plant investors will obviously base their choice on price projections rather than historic prices as shown in the graph. Prospective prices may change with new investments.

Figure 19. Fraction of new built/planned gas-fired power plants of total conventional power plants



Source: Platts, Frontier Economics

One important conclusion can be derived from the Italian example: it is not clearly possible to observe that the level of prices between bidding zones has had a substantial impact on investors' locational decisions. Other factors appear to also significantly affect locational choices.

Case study – Nodal prices in PJM – the impact of long-term reliability

In the following we discuss nodal prices in PJM. As long as, nodal pricing is an extreme form of bidding zones, where each node represents a bidding zone, the experiences gained from PJM are of interest to our discussion of market splitting.

PJM (Pennsylvania-New Jersey-Maryland) started its operation in 1 April 1998 and currently covers a region with 51 Mio. people, 170 GW of generation capacity and 500 market participants. PJM Interconnection, L.L.C. acts as the *Independent System Operator* with 3.000 nodes and central dispatch. PJM consists of different markets:

- Day-Ahead Energy Market;
- Real-Time (balancing) Market;

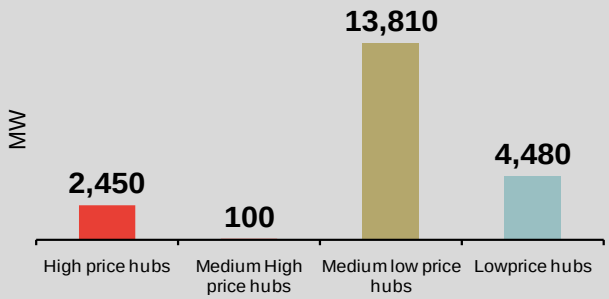
Market splitting – generalised evaluation approach

- Financial-Transmission-Right Market (last amendment 2003);
- Capacity market (since 2007).

In the Day-ahead market for every node *Locational Marginal Prices* are calculated consisting of an energy, congestion and loss component. The Locational Marginal Prices provide very detailed information on the supply-demand situation and congestion at each node. Investors should locate their power plants at high-price nodes in the network.

For the period 2000-2006 the correlation between high price areas and investments into new generation was not straightforward. There is no clear empirical evidence between investments and Day-ahead *Locational Marginal Prices*. Investments into new power plants took place not in the high price but in the low price hubs in the period 2000-2006.

Figure 20. Investments in new generation PJM (2000-2006)



Source: Synapse Energy Economics (2006)

The reasons for this observation may be manifold:

- the observation period is too short;
- other location factors are more important; and/or
- the price signal from the Day-ahead *Locational Marginal Prices* was too volatile or weak and there was a lack of long-run reliability.

The latter point was tackled by adding a regionally differentiated capacity market to the energy market in 2007. The capacity market should give more stable, i.e. less volatile, and long-term reliable locational price signals for investors.

Two important conclusions can be derived from the PJM example:

- **Volatility of prices** – High price volatility due to small bidding areas tends to outweigh the advantage of very locationally specific signals;
- **Reliability of signal** – Due to the long-term characteristic of investment

into power plants, the corresponding locational signals should also be long-term.

Locational signals from electricity prices for power plant investments – Summing up

Bidding zones with electricity price differences send locational signals to investors in generation. To what extent investors can and will react with choices of plant location depends on several factors:

- the level of price differences between bidding zones and the absolute level of prices in the high price zone;
- volatility of the price signals;
- long-run reliability of the locational signal, e.g. small and / or moving bidding zones can be in conflict with long-run reliability; and
- other locational factors.

The locational signals from market splitting have to be benchmarked against alternative incentive systems inside a bidding area, e.g. entry/exit grid tariffs, which may be better able to deal with specific locational needs.

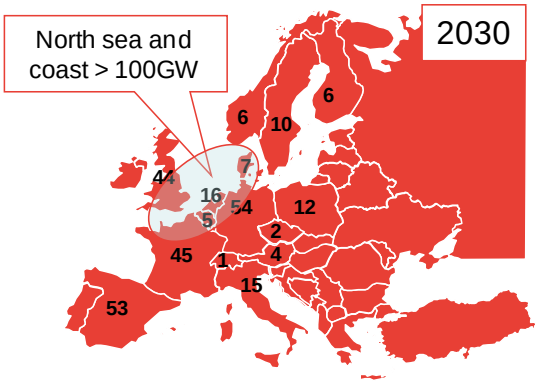
3.6.4 Dynamic Efficiency – Locational signals from electricity prices and Renewables[47]

To a large extent the reward for renewables comes from feed-in tariffs or other support schemes, e.g. renewable obligations as in UK, Belgium, Sweden. This leads to a decoupling of revenues from electricity market prices. Thus, for investors into renewables other locational factors instead of the electricity market price will dominate their investment decisions.

The EU has set itself ambitious climate targets, which include the substantial expansion of generation from renewables generation formulated in national action plans. It is planned that in 2034 34% of electricity demand will be covered by production from renewables compared to 15% today. The potential from hydro power generation is nearly exhausted, hence the bulk of new renewables generation will come from subsidised sources, especially wind power followed by bio mass and photovoltaic. The majority of wind generation will be located in coastal areas in the north of Europe (**Figure 21**).

47 For a detailed discussion on wind power and locational market signals see: Céline Hiroux and Marcelo Saguan, *Large scale wind power in European electricity markets: time for revisiting support schemes and market designs*, LARSEN Working Paper No 23, 2009.

Figure 21. Forecast wind capacities 2030



Source: Frontier Economics based on Trade Wind

The increase of volatile wind generation on the total generation mix will pose challenges to the whole European electricity system:

- *Regionally concentrated and distant to load production* – Wind availability and total costs restrict wind sites to certain areas, especially near the coast. Load remains inside the country; and
- *Divergence between production and demand* – Wind production is driven by the weather and not demand and/or price signals.

The decoupling of revenues for renewable from electricity wholesale market prices lowers the location steering effect of market splitting with respect to renewables. If the coastal area overlaps with a low-price bidding zone, indicating less need for new generation capacities, this will not change the investment decision of investors in renewables. In order to relieve congestion, new transmission lines are necessary to transport the electricity to the load centres (Redispatch of existing plants can only support grid reliability to a limited extent).

Electricity prices and Renewables – Summing up

Market splitting will not have an impact on the locational decision for wind power plants, because given the current design of renewables support schemes, investors do not place much weight on the electricity market price in their locational decisions. Locational signals for conventional plants may ease the effect of volatile wind generation. However, new transmission lines are needed to transport the electricity from renewable generation to the load centres.

3.6.5 Dynamic Efficiency – Locational signals from electricity prices for demand

The effect of locational signals from electricity prices for decisions on the location of demand is similar to the effect on the location of generation. Lower wholesale prices in non-congested bidding areas provide a signal to consumers to locate in this area. Hence, new load near generation capacity will reduce load flows into other areas, in turn reducing congestion.

Whether investors will react on price signals also depends on other factors in the bidding areas, e.g.: availability of sites, infrastructure of the region to attract employees and access to resources, trained personnel and transportation. Local and regional governments play a further role in attracting new industries by e.g. granting exemptions from local taxes, providing land for free.

In the following, we will discuss two questions concerning locational signals:

- *Customer type* – How will different customers react on price signals?; and
- *Characteristics of electricity price* – How will market splitting change the characteristic of electricity prices?

Customer type

In order to discuss the impact of locational signals from electricity prices it is necessary to differentiate between customer types. We differentiate between:

- *Small customers* – Households, commercial and small/medium sized industrial customers; and
- *Large customers* – Large industries.

For households the electricity bill is only a small part of total expenditures. Furthermore, commercial and small/medium sized industrial customers, for whom electricity prices constitute an important cost, typically compete with firms in the same bidding zone and are therefore exposed to similar prices. Hence, we do not expect that small customers will change their location based on lower prices in a bidding area, because other locational factors dominate the price of electricity.

Market splitting – generalised evaluation approach

The competitive pressure for large customers may be different. They face competition at an interregional and / or global level. Hence, large energy intense industries take into account the electricity bill as one important and substantial cost component, which has to be competitive in national and international comparison. For these customers, locational signals from electricity prices play a major role in the consideration of locational factors. In the following, we will focus our discussion only on large energy intense customers.

Characteristics of locational signals from electricity prices

The risks facing large customers are similar to those for generators:

- volatility of the market signal; and
- long-run reliability of the market signal.

Large customers will face more volatility prices in smaller bidding zones. One strategy to cope with this is to enter into long-term contracts and reduce dependence on short term price signals from the wholesale market.[48] However, long-term contracts will typically include a price formula linked to a reference price. This price might be an average – to cancel out a large degree of volatility – price specified for a certain location in the bidding zone. In this way large customers will be exposed to regional electricity price signals even if they procure power through medium to long term contracts. Whether this affects their locational decisions (to relieve congestion) depends on

- the importance of electricity prices to the business; as well as
- other factors, such as site availability, etc.

Moving borders between bidding zones can jeopardize the value of the long-term contract, if the reference price moves into a high-price bidding zone.

Hence, market splitting increases the complexity of electricity procurement for – all – customers, which reduces the benefits from locational signals.

48 This has a negative effect on the number of market participants in the wholesale market and on market liquidity.

Locational signals from electricity prices for demand – Summing up

Bidding zones with electricity price differences will only send effective locational signals to large energy intense industries. Similar to the case of generators, the impact on the locational behaviour of consumers depends on several factors. Of high importance is the long-run reliability of the locational signal. Small and / or moving bidding areas can conflict with long-run price reliability, which would tend to counteract the advantages from locational electricity price signals.

3.6.6 Dynamic efficiency – Incentives for grid investments from market splitting

Market splitting affects two types of investors in transmission grids:

- regulated transmission operators; and
- merchant investors.

Regulated transmission operator

If congestion arises in a bidding area, the transmission system operator solves the congestion by redispatching power plants to reduce the load flow on the affected congested line. Resulting redispatch costs could enter into network tariffs. The regulator can treat these costs in different ways resulting in different incentives for reducing congestion costs, e.g. by investments into the grid or by other means:

- *Congestion costs as cost-pass-through element* – in this case the transmission operator is allowed to pass-through all congestion costs to network customers, independently of their amount.
- *Incentive regulation on congestion costs* – in this case the regulator sets incentives for the transmission operator to reduce congestion costs. This can be done by setting a reduction targets for congestion costs. If the transmission operator beats the target he can keep all or some of the cost difference as an extra profit. Hence, the transmission operator has an incentive to reduce the congestion costs and, depending on the regulatory mechanism, to target the optimal cost.

By splitting the bidding area along structural congestion, different electricity prices will prevail in the resulting bidding areas. The difference in prices will reflect the congestion rent. In the case of auctioning the scare transmission

capacities between the bidding areas, congestion costs turn into congestion revenues which may be allocated to the regulated transmission operator.[49]

Turning congestion costs into congestion revenues may have an adverse effect on transmission investments. As long as congestion generates revenues for the transmission operator their incentives to reduce congestion decreases compared to the case of one bidding zone, where congestion generates costs, which the TSO may or may not be able to pass on through tariffs (depending on regulation). Transmission operators worry less about high congestion revenues, even if they must pass them on to customers, than about high congestion costs, especially if the pass-through to customers is restricted by incentive mechanism. This may have the adverse effect – if unaddressed – that incentives to fundamentally relieve grid congestion by grid investments may be lower in a market splitting regime than with wider bidding area.

Furthermore, market splitting may have additional dampening effects on investments:[50]

- *Local resistance* – Market splitting makes transparent the potential winners and losers from a congestion relieving investment. This will increase the resistance of the losers from grid investments (namely consumers in the low price area), amplifying existing public resistance.
- *Impact on authorities* – Market splitting may reduce the pressure on authorities to speed up the permission procedure, because authorities may argue that market forces are still at work optimizing congestion management.

Merchant investors

Bidding zones with electricity price differences create profit opportunities for investors into transmission lines by making transparent congestion rents. However, the exploitation of the congestion rent by entrepreneurs depends on at least three conditions:[51]

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49 In a region with implicit capacity auctions as in the Nordpool region congestion revenues are collected by the market operator, but may be paid out to the TSOs.

50 Some also argue that these dampening effects on transmission investments reduce the qualification of market splitting as a transitory instrument for congestion management until necessary transmission investments are finalised. It may be the case that these investments will not be undertaken under market splitting, hence, market splitting becomes permanent and not only transitory.

51 For a detailed discussion on merchant transmission investment, we refer to: Gert Brunekreeft, *Market-Based Investment in Electricity Transmission Networks: Controllable Flow*, CMI Working Paper, 2003.

- *High congestion rents* – congestion between bidding zones have to be large enough to fuel the investment and must remain at high levels over the life time of the asset;
- *Controllable flows* – the flows on the line must be controllable in order to calculate the future revenues for the investor. Loop flows via meshed networks make the merchant model less applicable; and
- *Profits cover higher expected risks* – the returns from the new line may need to be higher than compared with a regulated grid investment, because the revenues to a merchant investor tend to be more uncertain.[52] As a consequence, hurdle rates for investors are higher.

Merchant investments in the transmission grids are the exception in the European electricity market. National regulators can grant exemptions from regulation if certain criteria are met. The EU Commission is reluctant to grant exemption from regulation for merchant lines. at any rate, one can doubt that in the meshed continental Europe transmission network merchant investment is a viable option for grid expansion except very dedicated links.

52 The risks of a merchant project are the same as those of a regulated project. In the regulated model the risk is borne by captive customers in the wider region, in the merchant model they are borne by the merchant investor.

Incentives for grid investments from market splitting – Summing up

There are two types of investors for transmission grid:

- regulated companies; and
- merchant investors.

Market splitting will have varying effects on the investment incentives for these two types of investors:

- Regulated company – a possible **reduction** of incentive because
  - congestion *costs* turn into congestion *revenues* (this may be countered by additional regulatory measures); and
  - local resistance may increase and the pressure on authorities to fasten up the permission procedure may reduce.
- Merchant investors – **increase** of incentive, because differences in electricity prices make congestion transparent creating a profit opportunity. However, the merchant model only fits certain connections and not investments in meshed grids and within country.

As long as the meshed European network restricts the exploitation of congestion rents for merchant investors, the reduction of incentives for grid expansion is likely to outweigh the potential increase from merchant investors when market splitting is introduced. In other words, market splitting may have the indirect effect of reducing network investments that would otherwise remove congestion.

3.6.7 Competition and Market concentration

Market power is typically defined as the ability to profitably increase prices above competitive levels. The possibility to profitably exercise market power depends largely on the number of competitors in the relevant market and the extent to which they are able to meet market demand at competitive prices before their generation capacities are exhausted. In a perfectly competitive market an undertaking is unlikely to offer output above marginal costs, when it is paid the system marginal price through a power exchange. If the undertaking were trying to mark up prices it would be displaced by other bidders. In oligopolistic or monopolistic markets the profitability to alter prices and / or quantities increases potentially leading to welfare loses.

Market splitting along structural congestion scales down the market into smaller regions. This tends to result in higher market concentration in the new bidding zones raising the possibility that major player profitably exercise market power.

Market power can affect two markets:

- the wholesale market; and
- the retail market.

Wholesale market

In the wholesale market, the primary methods of exercising market power are:[53]

- *Physical withholding* – this means deliberately reducing the output that is bid into the market even though such output still existed at marginal cost below the market price; as well as
- *Economic withholding* – this means bidding prices higher than the marginal cost of the generation unit.

The relationship between the size of the bidding zone and the possibility of exercising market power can be illustrated by the withholding strategies.

The profitability of physical withholding depends on:

- the effect of the withdrawn capacity on the spot electricity price; and
- the remaining dispatched generation portfolio of the undertaking.

The marginal profit from selling the remaining – but now smaller – output at higher prices must be higher than the marginal loss from not selling the output from the withdrawn power plant. The impact of one particular generation unit on the electricity price will be higher in smaller bidding zones. If the owner of this particular generation unit has a substantial generation portfolio in the bidding zone, then physical withholding of this plant tends to be more profitable.

The potential for economic withholding may be explored through the concept of pivotal supplier. A generator is necessary ("pivotal") in serving demand if its capacity is larger than the surplus supply (the difference between total supply by other players and demand) in the wholesale market. The smaller the bidding zone, the more likely it is that one generator becomes pivotal and can gain from bidding prices above competitive levels. Moreover, we want to stress that during periods when the system demand is close to capacity, a supplier can become "pivotal" even with a relatively small market share.[54]

The exercise of market power would on the one hand increase the wholesale electricity price. On the other hand, it would reduce the dispatch efficiency of

53 In its sector inquiry the Bundeskartellamt try to estimate the potential for this behaviour (see Bundeskartellamt, *Sektoruntersuchung Stromerzeugung Stromgroßhandel, Bericht gemäß § 32e Abs. 3 GWB*, Januar 2011).

54 Whether a pivotal player also has incentives to withhold depends on further factors such as the risk of intervention by authorities etc.

power plants in the case of physical withholding, because more expensive plants have to go online to cover demand.[55]

The argument as presented so far presumed that all power is sold through the spot market. Twomey et al (2005)[56] point out the important relationship between various wholesale markets including the spot, day-ahead and forward market. Generally, it is assumed that competitive spot markets will discipline forward markets and vice versa. Conversely, non-competitive behaviour in either market will have a feed back on other markets.

Tworney et al (2005) explain that even in the case of competitive spot markets sellers could exploit market power in the forward market. The disciplining effect from spot on forward markets only relates to the component of forward prices that depend upon spot price expectations. It does not mitigate the part of forward prices that depends on buyers' risk aversion. Hence, sellers in regions with limited competition may be able to extract market power rents from buyers' willingness to pay for price certainty[57]. Additionally, given that the forward price risk premium is related to spot price volatility generators with market power have an incentive to create volatility in the spot market. The possibility of influencing spot prices increases as the size of the bidding zone decreases.

However, the last problem – increased forward price risk premium by increasing spot price volatility – can be mitigated by the institutional set up of the wholesale market. The wholesale market can cover several bidding zones, and the relevant

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55 Some argue that market power can be dealt with by increasing the market transparency. Published information on available generation capacities, bids of generators and network situation should prevent the abuse of market power. There are some caveats to this argument. Real time disclosure of information tends to increase not decrease the problem of abuse of market power by dominant – better pivotal – generators, because they can better adapt their bids to those of the other market players. Hence, market transparency must not be real time but ex post. The gathered data are used by regulators or competition authorities ex post to detect the abuse of market power. However, there is a danger that ex post monitoring slowly glides into heavy-handed regulation. As a consequence there are good arguments that competition policy should focus on structural remedies, e.g. decreasing market shares by extending the geographic/product market, in order to deal with the problem of abuse of market power. A special case might be the hydro dominated Nordpool area, where the marginal costs of hydropower plants is not straight forward and may differ among market players. Thus, it is complex for one single market player to place a strategic bid when he does not know the subjective believes of all other market players in the marginal cost – value – of hydro power.

56 Paul Twomey, Richard Green, Karsten Neuhoff and David Newbery, *A Review of the Monitoring of Market Power*, CMI Working Paper 71, 2005.

57 "If market monitors do not directly mitigate market power in forward markets, sellers in regions with limited competition may be able to extract market power rents from buyers' willingness to pay for price certainty. In other words, they will obtain in the forward market rents that they cannot obtain in the spot market. Thus, to the extent that load serving entities cannot afford to wait around for the spot market to ensure long-term supply stability, short-term mitigation will not necessarily put adequate competitive pressure on sellers with market power with regard to the forward market." (Tworney et al, 2005: 7)

reference spot price for the forward market could be defined as a system price (as in the NordPool region). The system price is based on the actual aggregated bid and offer curves under the assumption of no congestion between the bidding areas. Including all aggregated bids of several bidding zones reduces the impact of one generator on the system spot price.[58]

However, introducing a system spot price only mitigates market power at the system but not on the local – bidding zone – level. Market power in spot markets in each bidding zone can occur when congestion constraints between bidding zones are binding. Generators with a big market share and / or pivotal suppliers may still be able to profit from strategic behaviour. Steen (2005)[59] estimates the local market power in one bidding zone (South Norway) in the NordPool market for the period 2001-2002. The results show a significant but small short run mark up on competitive prices when congestion constraints are binding. Hence, within the day or hours when bottlenecks appear it seems that the producers exploit some limited market power according to this study.

More generally, Bask et al (2007)[60] show the effect of an expansion of the market size on market power based on the NordPool region. They conclude that there has been a small, but statistically significant, degree of market power in relation to the system spot price during the period 1996-2004. However, their results also show that the degree of market power on the system spot price has been reduced as the market has expanded to Finland and Sweden. Market participants recently expressed concerns that the upcoming market splitting within Sweden would lead to high market concentration in two of the four national bidding areas. This may increase the risk of abuse of market power. Even for those players that may be in a superficially favourable position the development can be understood as a step backwards, because the new situation may provoke stronger regulatory oversight of any market activities.

Retail market

The economics of the retail business is critically driven by economies of scale. There are a number of costs associated with entering this market, and then expanding to reach scale. These include investment in IT systems and call centres and the costs associated with building a brand and acquiring customers. Because customers' willingness to switch their suppliers tends to be low, new entrants need a big market potential to acquire a critical mass of customers to break even.

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58 This is the institutional set up of the NordPool market (see Section 3.6.8)

59 Frode Steen, *Do Bottlenecks generate market power? An Empirical Study of the Norwegian Electricity Market*, 2005.

60 Mikael Bask, Jens Lundgren, Niklas Rudholm, *Market Power in the Expanding Nordic Power Market*, 2007.

Splitting up a bidding zone into several zones can change the potential market size for retailers. This can affect retailer already active in the market or those willing to enter the market.

- **Active Retailers** – Retailers already in the market will have to change their business strategy. They must decide if their new relevant market for customer acquisition includes just one new bidding area or all of them. If it consists of several bidding areas, retailers have to change their electricity procurement strategies taking into account the price difference between bidding areas. Hence, procurement will become more complex and have to include new hedging instruments. Additionally, administration costs will rise when the retailer serves all bidding areas. Hence, higher costs will drive down margins. In the worst case the business case will become negative, forcing marginal retailers to exit the retail market. On the other hand, if the retailer restricts its activities just to one bidding area, it might be impossible to acquire enough customers to break even. Again, this might force the retailer to exit the retail market.

- **New Retailer deciding to enter market** – The retailer planning to enter the market will have to recalculate its business plan taking into account the effect on procurement costs, marketing costs, market size, etc. Higher costs or smaller market potential can make the business case negative discouraging new entry.

Hence, market splitting tends to increase market entry barriers in the retail market. As a result, incumbent retailers may raise retail prices above levels that would prevail without market splitting. In economic terms the retail market becomes less contestable, because the lower threat of new entry puts less discipline on incumbents' behaviour. There are first indications that this is currently happening in Sweden as a result of market splitting due to the Svenska Kraftnät case.

Competition and market concentration – Summing up

Smaller bidding areas tend to have an adverse effect on the market structure and competition on the wholesale and retail markets, because the probability of profitable exhibition of market power by incumbent market players increases.

On the wholesale level market power may increase prices and can distort the efficient dispatch of power plants. Additionally, the quality of information conveyed by prices to market participants in the spot and forward market could decrease. Hence, market power reduces the confidence in the wholesale market, discouraging market players to participate.

On the retail level entry barriers for independent retailers tend to increase when forming smaller bidding zones, forcing some retailers out of the retail market and / or preventing some retailers from entering. Higher entry barriers will translate into higher prices for customers. Furthermore, less entry into and more exit from the retail market reduces the number of market participants on the wholesale market, as well.

There is a strong relationship between market concentration and market liquidity.

3.6.8 Market liquidity

A liquid wholesale market is important for the functioning of the market. For example, it:

- facilitates new entry in generation and supply by allowing new entrants to buy and sell electricity to match their output and customer base with confidence;
- reduces the ability of market participants to engage in market manipulation;
- increases confidence in traded prices; and
- provides a wider range of products and counterparties for participants to hedge their risk exposure.

Market liquidity can be defined as the ability to quickly buy or sell a desired commodity or financial instrument (*The market has immediacy*) without causing a significant change in its price and without incurring significant transaction costs (*The market has resilience*). There are at least three dimension of market liquidity:

- traded volumes;
- number of market participants; as well as

Market splitting – generalised evaluation approach

- "depth" of the market.[61]

Splitting the bidding zone will impact all three dimensions. For example, reducing the size of the bidding area may deter market participants from trading, which results in a reduction of traded volumes and possibly depth of the market. As a consequence the confidence in the underlying price for financial contracts may decrease.

In the following we discuss two issues in relation to market splitting and their effect on overall market liquidity:

- organisation of the wholesale market; and
- financial risk introduced by market splitting.

Organisation of wholesale market

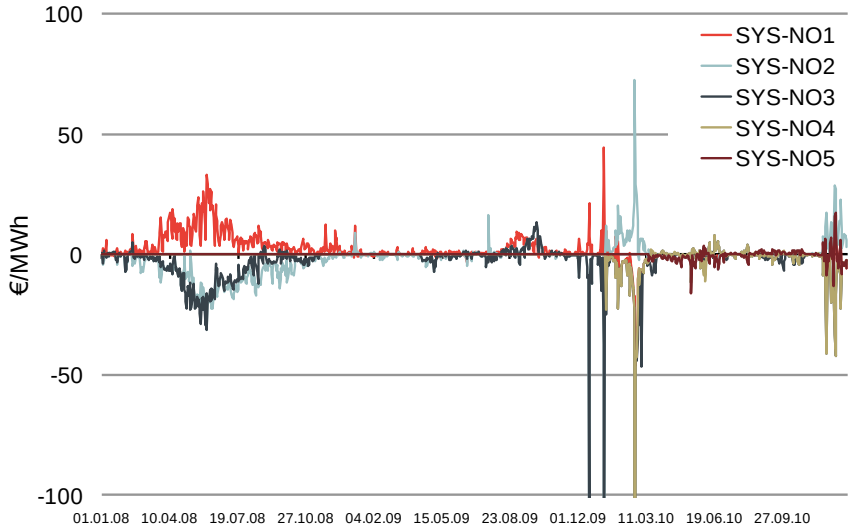
There are two options to organise the wholesale power exchange market, when a bidding area is split into several bidding areas:

- **Option 1** – Wholesale market covering all bidding areas with a virtual system price for all bidding zones as reference price for forward contracts;
- **Option 2** – Wholesale market for each bidding area.

Option 1 corresponds to the NordPool market organisation. Currently, NordPool covers 10 bidding areas in four countries. NordPool uses market splitting to cope with congestion between the bidding areas, resulting in differing area – bidding area – prices if congestion constraints are binding. However, in order to pool market participants in the forward market NordPool simultaneously calculates a system spot price, which is the relevant settlement price for all forward contracts. The system price is calculated based on the actual aggregated bid and offer curves under the assumption of no congestion between the bidding areas. Hence, the system price can and does differ from the area prices. For example, the difference between the system spot and the area prices in Norway tended to be non-zero between 2008 and 2010 (**Figure 22**).

61 The depth describes how market prices respond to large transactions in the market. If a single transaction does not significantly affect prices, the market is said to be liquid and deep.

Figure 22. Difference between NordPool System Price (SYS) and Area Prices in Norway (NO1-5)

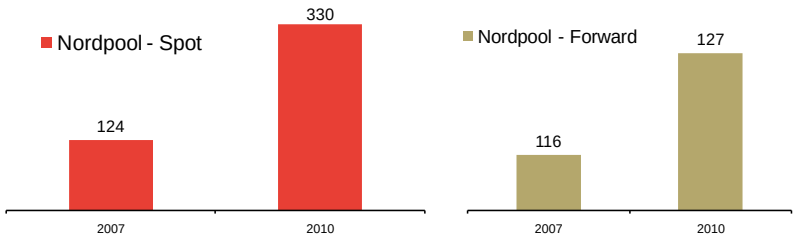


Source: NordPool

One advantage of the system spot price is that at least in the forward market the size of the market, now consisting of several bidding areas instead of one, does not change as a result of market splitting. The impact on market power in the spot market due to the system spot price is not so clear. On the one hand, one could argue that the exercise of market power of an undertaking in one bidding area has only a small impact on the system. On the other hand, the exercise of market power of one and/or many undertakings in different bidding areas, will also affect the system spot price because it distorts the aggregate supply curve. Hence, market power in one bidding area may as a second order effect distort the confidence in the underlying reference price for the forward market.

The number of participants in the spot and forward markets at NordPool (**Figure 23**) and the turnover of volumes indicate that *Option 1* is a viable organisation of the wholesale electricity market in the case of market splitting.

Figure 23. Number of market participants in the NordPool Spot and Forward market



Source: NordPool

However, there are many aspects to specify when introducing this new organisation, e.g.:[62]

- Who is the owner of the cross-border capacities between bidding areas? Is there a difference between annual, monthly and daily capacity rights?; and
- Who operates the market coupling?

In *Option 2* the size of the spot and forward market will be divided into several bidding areas resulting in a reduction of the size of each market (compared to the integrated market). Hence, we would expect an adverse effect on market liquidity in the individual bidding areas caused by:

- **Reduction in market participants** – Power exchange market exhibit economies of scale, market participants are attracted by potential counterparties and vice versa.
- **Reduction in the depth of market** – The reduction in market participants will feed back into the depth of the market, leading to a reduction of liquidity in the forward market.
- **Market power** – The smaller the bidding zone the higher will be the potential for the exercise of market power in the spot market. This could result in a distorted market prices which would in turn reduce the confidence in the price signals from the power exchange.

From the point of view of market liquidity, *Option 1* would be at least as good as *Option 2*, and probably preferable.

62 This are typically transaction costs dealt with in Section 3.6.9. But we think it is important to highlight some costs at this point of the report, as well.

Financial risk

Splitting one bidding zone into several zones and organising the wholesale market according to *Option 1* introduces a new trading risk (financial risk) into the market arising from congestion. The risk consists of the divergence between the price that a participant pays or receives in the spot market – the price in each bidding area – and the price at which its financial contracts are settled – the system price. These differences can be substantial as indicated by the NordPool market (see **Figure 22**). In a market with one bidding area this risk does not arise because the spot price and the settled price for financial contracts relate to the same bidding and delivery area.

This divergence between the price a participant pays or receives in the spot market and the price at which its financial contracts are settled occurs when:

- participants have entered into financial contracts with participants located in another bidding area; and
- transmission constraints that restrict flows on interconnectors between those bidding areas bind, causing the relevant spot price in the bidding zone to diverge from the system price.

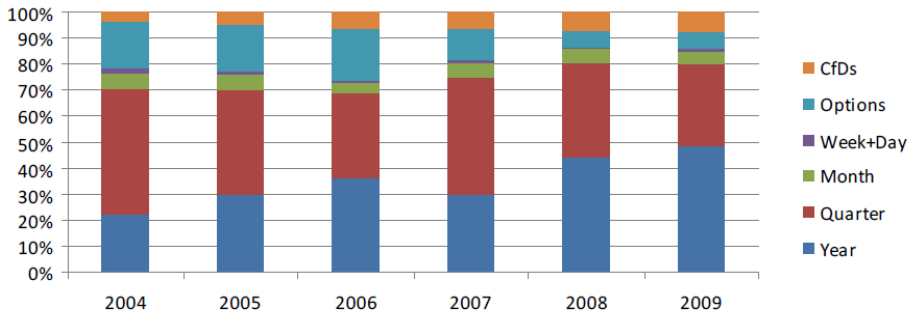
There are several ways of dealing with this financial risk.

The NordPool area uses *Contracts for differences (CfD)*. A CfD is a forward contract with reference to the difference between the Area Price and the Nord Pool Spot System Price. At the time of trading the market price of a CfD reflects the market's prediction of the price difference during the delivery period. CfDs trade at positive prices when the market expects a specific area price to be higher than the System Price. CfDs will trade at negative prices if the market anticipates an area price below the System Price. CfD theoretically provide the possibility for a perfect hedge even when the markets are split into one or more price areas.[63]

However, the experience with CfD is mixed in the NordPool area. The share of CfDs in the forward market doubled since 2004 (**Figure 24**). Area price risk management has become a much more important part of risk management strategies, especially for retailers in Denmark, Finland and Sweden but also for customers in these countries. However, there is still limited liquidity in CfD contracts. Market participants complain that the "insurance premium" for CfD-contracts is too high in relation to the expected magnitude of the area price risk. For all CfD contracts there is a limited number of sellers and the participation by financial traders is small. One reason is that the CfD contracts are seen as much more likely to suffer from market power than system price contracts.

63 NordPool, *Trade at Nord Pool ASA's financial market*, 2010.

Figure 24. Share of products in forward market (percentage of traded MWh)



Source: NordReg

Hence, the area price risk is in many cases not hedged and removed and is instead borne by the market players. Additionally, the area price risk is often borne by customers through variable price contracts.[64]

Another option to hedge the financial risk are *Financial Transmission Rights* (*FTR*), currently used in the PJM nodal pricing market. FTRs are instruments that provide their holders with a stream of revenue derived from the differences in nodal – bidding zones – prices that occur when transmission limits bind. Introducing a system of FTRs is complex and consists of various steps:[65]

- *Formulation of FTRs* – FTRs can be point-to-point instruments, defined according to their point of receipt (power injection point) and point of delivery (power withdrawal point). FTRs can be obligations or options. An FTR obligation provides a credit (positive or negative), equal to the product of the FTR MW amount and the congestion price difference between the withdrawal and entry points. FTR options only provide positive credits.
- *Revenue adequacy* – This means that the net revenue collected through the settlement process from the entire set of nodal prices should at least be equal to the payments to the holders of FTRs in the same period.
- *Allocation of FTRs* – A crucial issue involves the – initial – allocation of FTRs. This could involve an auction/tender process or an administrative allocation method. E.g. FTRs were initially allocated to incumbent participants who paid regulated transmission tariffs in PJM.

64 For a detailed survey on the NordPool financial market see: NordReg, *The Nordic financial electricity market*, Nordic Energy Regulators, Report 8, 2010.

65 For a detailed discussion see: Frontier Economics, *Generator Nodal Pricing – a review of theory and practical application*, A report prepared for the Australian Energy Market Commission, 2009.

However, due to the competitive advantage this gave to incumbents, the rules were changed in June 2001 so that PJM treated all requests for FTRs identically.

The PJM example shows, that the formulation and allocation of FTRs is a complex process with ongoing reforms.

Market Liquidity – Summing up

Splitting up one bidding zone can be accompanied by two measures to keep market liquidity at high levels:

- *Organisation of wholesale market* – Wholesale market covering all bidding zones with a virtual system price for all bidding zones as reference price for forward contracts; and
- *Financial risk* – hedging instruments based on *Contract for Differences* and / or *Financial Transmission Rights*.

But issues still remain, which can put market liquidity at risk:

- It is unclear how market participants will react to a change in wholesale market design. One possible reaction could be that some participants just "lean back and wait what happens" causing liquidity to fall.
- Another reaction could be that some market participants, e.g. independent retailers, exit the market, because hedging against financial risk becomes too complex and is not justified by expected retail margins any more.
- The new financial risk might be directly priced into the spot and / or forward price.
- Last but not least, market participants could hedge themselves with physical assets by vertical integration, which could further reduce liquidity.

3.6.9 Transaction costs of Market Splitting[66]

In this section we discuss the transaction costs for splitting a bidding zone into several zones. Before discussing the transaction costs, we comment on the lead time for implementing market splitting.

66 For a detailed illustration of the transaction costs and lead time for implementing market splitting we refer to: Frontier Economics/Consentec, *Methodische Fragen bei der Bewirtschaftung innerdeutscher Engpässe im Übertragungsnetz (Energie)*, Untersuchung im Auftrag der Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen, 2008.

Lead time

The leading principle governing the implementation of market splitting should be that the impact on the existing market institutions and contracts in wholesale and retail markets are as small as possible. This is because a change in market design and the creation of new bidding zones is likely to require a respecification of delivery points in all existing and legacy supply contracts. A simple route would be to only change the market design from a date for which supply contracts are not yet liquidly traded. A good indicator for the minimum lead time is the depth of the forward market. For example, liquid three years forward products could imply a minimum lead time of 3 years. The alignment of the lead time to depth of the market reduces uncertainties of all market participants to a minimum. Additionally, it allows market participants to progressively adapt to the new market design and settle their existing power contracts. In the retail market it allows retailers to adapt their contracts with customers, as well, dampening the negative effect from annual fixed price contracts.

Experiences, e.g. from changing market designs in the UK from the Pool to NETA and from NETA to BETTA are that transaction costs can be significant. However, a significant part of that cost may be avoidable, if sufficient lead time is given for the introduction of the new regime.

Primary measures

By primary measures we understand measures which are directly related to the change of the market design. Usually they follow a sequential path:

- changing the legal framework;
- deciding on the new market design (e.g. market splitting);
- definition of new bidding areas and transmission capacities between bidding areas;
- allocation of new transmission capacities between bidding areas (day-ahead, month-ahead, year-ahead);
- establishing a central clearing house; as well as
- IT costs for market participants (e.g. power-exchange, traders, etc.).

The level of transaction costs for primary measures depends on the degree of the change in market design.

Secondary measures

By secondary measures we define measures which are the consequence of the institutional change:

- new definition of balancing zones;

- new valuation of contracts/positions; and
- costs for renegotiation of power contracts if the reference price changes or is not accepted by contract parties any more.

The costs for renegotiation of power contracts can constitute a significant burden on smaller market participants. Moreover, these costs are not only restricted to market participants in the affected bidding areas, if market participants outside the bidding area used the market price as their respective reference price.

Besides the monetary transactions costs, there are qualitative transaction costs, as well. We summarize them as reputational effect, e.g.:

- Market participants might lose confidence in the market, if they do not understand why a functioning market design is changed.
- Market participants in countries with less developed markets will lose confidence in the reference price of the market that changes its design. This might hamper the slowly growing wholesale markets in these countries, with a negative effect on European electricity markets as a whole.

3.6.10 Distributional effects

Splitting up bidding zones along structural congestion will create winners and losers. This is true even if the overall welfare gain through the new regime is relatively small. Resistance from an important stakeholder group can increase the costs or even prevent an institutional change. Economic theory provides a solution how to overcome the problem of public resistance due to the distributional effect. If welfare gains are high enough the winners can compensate the losers, which in theory results in a situation where both parties are better off than before or at least no one is left worse off and some are better off.

Bidding areas tend to benefit two groups of stakeholders:

- generators in the high-price bidding zone (high load – low generation capacity zone); and
- customers in the low-price bidding zone (low load – high generation capacity zone).

If bidding areas are moving then winners and losers can change over time. For example a generator near the border between two bidding zones might change its role, if the border shifts over time.

The complexity of the distributional effect can be amplified by other policy measures. For example, taxes to promote wind generation levied in all split

bidding zones can result in unexpected wealth distribution if one bidding zone disproportionately profits from the price dampening effect of wind generation.

4 Application to Germany-Austria

In this section we apply the framework developed on the previous section to a hypothetical market splitting of the current bidding area Germany-Austria. We want to note that based on our analysis of the network situation in Germany, there is currently no need for market splitting due to the lack of structural congestion.

4.1 Step 1 – Congestion analysis

As derived in section 3.4, it is only worth exploring market splitting, if the current and prospective network situation is characterised by locations of congestion that are both

- structural (and not only intermittent); and
- sustained (and not only temporary).

Structural vs. intermittent

It would have been beyond the scope of this study to perform a comprehensive analysis of options for network extension and to run technical and economic simulations in order to evaluate their cost and benefit (in terms of a reduction of short term generation cost). Nevertheless, the historical data that we have analysed in Section 2.2.1 clearly show that at least from historical experience only a single German transmission line may indicate a case of structural congestion, namely Remptendorf-Redwitz (cf. **Figure 3**). Yielding congestion frequencies below 2% all other congested lines clearly constitute cases of intermittent congestion. There may be other fundamental changes to the market under way, e.g. the possible early retirement of older nuclear power plants in Germany. As long as these events and their potential effect on grid congestion are uncertain it is hard to predict whether or what other divisions of split zones may be appropriate in the future.

Sustained vs. temporary

As we have already set out in Section 2.2.4 the network situation in Germany could be affected in the next years as a consequence of the expected continued growth of installed wind power in the Northern parts of the country.

In this context it strongly depends on the implementation of network extension projects whether Remptendorf-Redwitz will be a case of sustained congestion and whether new cases of structural congestion will emerge in the period from now until 2016.

Generally, the necessity of extending the German transmission grid has been confirmed by numerous studies, and the TSOs have been concretely planning

extensive reinforcement of their grids for several years. However, the implementation of most projects is behind schedule.

The urgency of the situation with respect to Remptendorf-Redwitz has meanwhile been recognised by all stakeholders. The authorisation procedure for construction of the new almost parallel line aimed at relieving congestion is already in an advanced state, and although it is behind schedule, we consider it very probable that Remptendorf-Redwitz will be relieved within the next five years.

In addition, a specific network extension act ("Energieleitungsausbaugesetz", EnLAG) officially declares the energy economic necessity of more than 20 extension projects and simplifies the respective authorisation and permitting procedures. Commissioning of many of these projects is foreseen within the next five years. As regards the credibility of these schedules one can on the one hand observe a certain delay of the original plans. On the other hand the importance of network extension is increasingly acknowledged by relevant stakeholders comprising, *inter alia*, the German federal government as well as the European Commission. As a consequence, in July 2011 the "Netzausbaubeschleunigungsgesetz" (NABEG, acceleration of network extension act) has come into force. It contains measures towards further streamlining the German authorisation procedures, e.g. by assigning to BNetzA the responsibility for crucial parts of these procedures that previously had been organised in a more decentralised manner. The general expectation is that the NABEG has the potential to improve the efficiency and transparency of transmission network expansion.

Consequently, even under consideration of recent delays in network expansion, we do not expect a significant aggravation of the congestion situation in Germany in the next five years. Such aggravation would only materialise if several network extension projects explicitly supported by law were not implemented on time. Thus, considering such aggravation to be a valid argument for potential restructuring of bidding areas would be equivalent to distrusting the effectiveness of existing legal provisions and of concrete enforcement plans. Moreover, there is a high risk that by announcing any rearrangement of bidding areas due to the expectation of delays in network extension, the incentives for all relevant parties to realise these extension projects may be undermined.

Conclusion on the nature of congestion in Germany-Austria

We conclude from the above considerations that we see presently and at least based on historic experience and in knowledge of the grid reinforcement projects that are in the pipeline no bottleneck in Germany that qualifies as structural and sustained. Thus, the necessary precondition for considering a split of the existing bidding area is currently not fulfilled. We note that this assessment could potentially change in case of drastic changes to the market, e.g. forced early

nuclear retirement. To date, though, not enough information is available to allow for an informed judgement, whether this requires a re-evaluation of whether structural and sustained congestions are imminent.

Nevertheless, we continue the evaluation in order to perform an "as if" application to the Germany-Austria case.

Consequences of the retirement of nuclear plants in Germany

As a consequence of the nuclear accident in Japan in March 2011, eight nuclear plants have been forced to retire from the German power system. Two of these had been out of operation for several years before due to technical problems. The effect of the generation of the remaining six ones, however, is included in the statistical data on network utilisation used for the analysis above. Hence, we will discuss in the following if and in which way the results of our analysis might be influenced by the recent developments in nuclear generation in Germany.

With an operational experience of only four months so far, no final conclusions are possible. Nevertheless, two main developments can be observed:

- Only one of the six plants which had been in normal operation before the enforced retirement is located in the North of Germany, the remaining five plants are connected to grid nodes in the southern parts of the country. Consequently, there is an increased transport within the German transmission system from North to South. The German TSOs have reported in the meantime that due to that increase in transported power the system operation has become more difficult and the number of necessary redispatch measures has risen significantly. Especially on already highly loaded lines, like the Remptendorf-Redwitz line mentioned above, congestion has become more relevant. The most critical aspects that have been reported with respect to secure system operation, however, are not related to line loading, but to voltage stability problems due to a physical lack of plants and thus a lack of reactive power in some grid regions. With respect to the question of structural and sustained congestion relevant for our considerations on bidding areas, we would therefore conclude that the recent changes in generation patterns might have led to a situation with more structural congestion than before. Nevertheless, none of these cases can be classified as sustained in our eyes. This is because significant network extension measures are expected in Germany for the next years. These projects have reached an advanced state of the authorisation and/or construction process. The planning underlying these projects was already based on the assumption of the nuclear phase out scenario for Germany in force from 2000 to 2010, hence very similar to the situation achieved now. It was furthermore intended to guarantee a transmission system free of structural congestion for these scenario conditions. Hence, we consider the increased loading of the German transmission system observed currently as a temporary phenomenon due to the sudden retirement of plants with a nominal power of about 5,000 MW. Given that adequate network extension measures to resolve these issues are planned to be realised within short time and that the government has put in place measures to accelerate the realisation of new line projects e. g. by the new NABEG, no sustained

congestion is expected. Hence, the recent developments do not generally change the assessment of our congestion analysis.

- Furthermore, as a consequence of the retirement of these base load plants the import and export balance of Germany has changed significantly. Being a net exporter for most of the time until March, Germany now has become a net importing country. Especially imports from France, Poland, Czech Republic and the Nordel system have increased, the export to other countries like the Netherlands has decreased. With respect to the load flows in the European transmission system this development leads to a reduction of loop flows in the transmission system, e. g. of Poland, the Netherlands and Belgium.

4.2 Step 2 – Technical effect of splitting of bidding areas

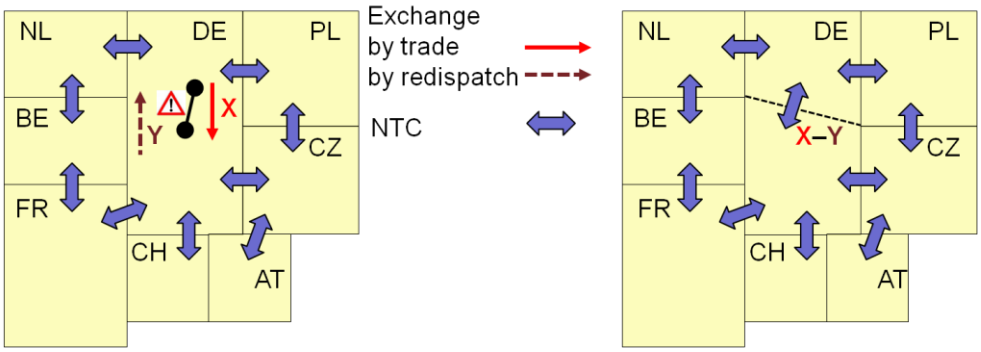
For the analysis of the technical effect of market splitting we discuss two questions:

- effect on amount of transmission capacities; and
- influence of renewable generation on the utilisation of transmission capacities.

4.2.1 Effect on transmission capacities

For the following considerations we assume a structural and enduring case of congestion inside a bidding area, e. g. in Germany. We further assume that congestion occurs due to excessive exchange of X from the North to the South of the bidding area (**Figure 25** left, arrow "X"). In order to keep the flow on the congested line within admissible limits, the TSOs apply redispatch of Y in the opposite direction (**Figure 25** left, arrow "Y"). Hence the net exchange between the Northern and Southern parts of the bidding area amounts to X–Y, which constitutes the technical limit for this exchange direction. (At times when the line is not congested the net exchange may be lower; but the more frequently the line is congested, the more certainly one can assume that the net exchange amounts to X–Y.)

Figure 25. Splitting a bidding area with internal congestion: effect on the amount of transmission capacities (schematic illustration)



Source: Consentec

If the flow on the congested line had to be limited by means of market splitting instead of redispatching, the bidding area would have to be split. The technical exchange limitation would then be transformed into a commercial limitation, i.e. an NTC. Assuming that prior to the split the cross-border transmission capacities were not misused in order to limit the loading of the congested line, the new NTC would be equal to the technical limit X–Y, while all previously existing NTCs would remain unchanged (**Figure 25** right).

There are, however, practical uncertainties that can have an additional effect on the development of transmission capacities:

- It is a well-known fact that NTCs are not unambiguous, i.e. there may be more than just one unique and feasible combination of NTC values on all relevant borders. Rather, they can be "shifted" between borders to some extent, i.e. several sets of regional NTCs can yield the same level of network security. The split of the bidding area, leading to the emergence of a new "commercial border", could be taken as an opportunity to re-negotiate the geographical distribution of NTCs.[67]

  For example, as we have shown in Section 2.2.3, the NTC from NL to BE could be increased by 1,000 MW at the expense of a reduction of the

[67] As the discussion around nodal pricing shows, it is thinkable to develop an algorithm that helps identify the cost minimising and secure set of NTC values. However, the result will be strongly driven by assumptions regarding the algorithm and the input data, so that in practice a negotiation of NTC values is likely.

maximum allowed exchange from Northern to Southern Germany by 4,000 MW, under some simplifying assumptions.[68]

- When determining the NTC for a given border, the TSOs have to make assumptions regarding the amount of power exchange across all other borders in the region. This is usually done on the basis of operational experience. The more fundamental a change of the bidding area structure would be, the less the TSOs could rely on their operational experience when determining the NTC figures. Moreover, the smaller and more numerous the bidding areas the less applicable is the NTC approach as such.

  In contrast, the flow based approach (FBA) provides inherent flexibility and is much less dependent on assumptions and heuristics. Consequently, a splitting of bidding areas would put pressure on the implementation of FBA if that was not even a prerequisite for an effective split (depending on how fundamental the change would be). The migration to FBA would very likely change the regional pattern of effective transmission capacities.

While the above mentioned uncertainties potentially affect the geographical distribution of capacity amounts when the constellation of bidding areas is changed, it is important to note that they do not directly originate from the assumed split of the bidding area. For example, the implementation of FBA is at any rate foreseen for the next years. By principle, FBA allows improving the economically efficient utilisation of the network infrastructure, irrespectively of a potential rearrangement of bidding areas.

We conclude that when splitting a bidding area in response to internal congestion (accompanied by frequent redispatching or countertrading), while there is some uncertainty as to the practical development of capacity amounts, there is no clear tendency that the amount of available transmission capacity on any particular border will rise.

4.2.2 Influence of renewable generation on the utilisation of transmission capacities

Relevance of renewable generation

While, as discussed in the previous subsection, splitting a bidding area may have only a limited effect, if any, on the amount of available transmission capacity, it is well possible that the commercial utilisation of transmission capacities may change. This is particularly relevant if generation and/or load are unevenly distributed among the newly emerging bidding areas.

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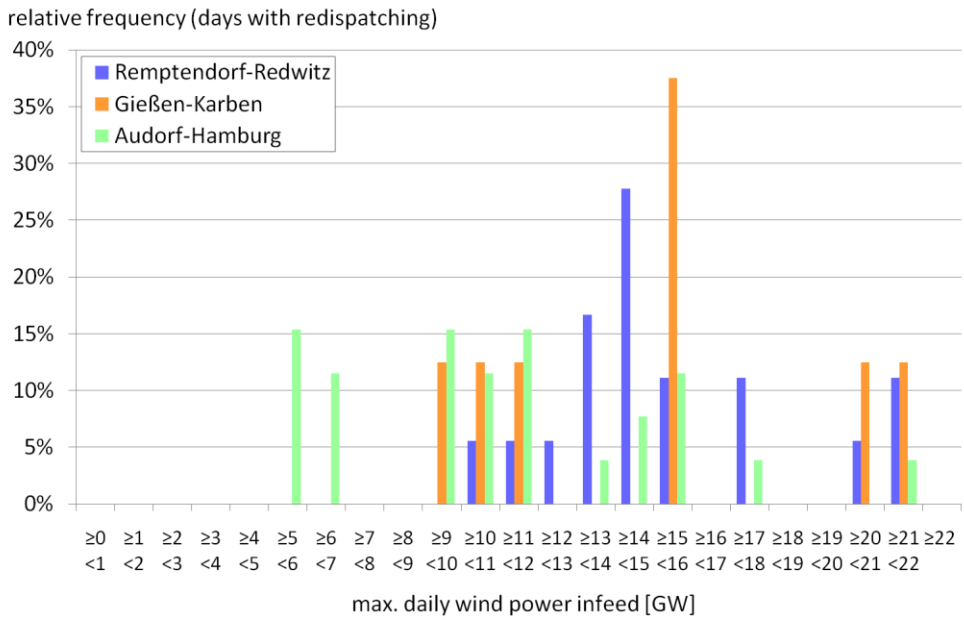
68 One of these assumptions is that no other network element besides the Dutch-Belgian tie lines becomes congested as a consequence of the NTC shift. If this assumption is not fulfilled, the increase of the NTC between NL and BE will be smaller.

In the German-Austrian bidding area, this is clearly the case, because there is a concentration of wind power in Northern and Eastern Germany. At times of strong wind this leads to a surplus of generation with marginal cost of zero. In fact, the occurrence of congestion on internal German transmission lines is strongly correlated with the amount of total German wind power infeed: As **Figure 26** shows, two of the three most frequently congested[69] internal lines (Remptendorf-Redwitz and Gießen-Karben) are never congested on days when total German wind infeed (daily maximum) is less than 9 GW, and two thirds of the congestion cases for Remptendorf-Redwitz are on days with maximum wind infeed of at least 14 GW. In contrast the line Audorf-Hamburg, which is located close to the Danish border, seems to be more strongly affected for other, more local reasons, as it is congested also at times of lower total German wind infeed. Given the facts that the situation in Germany does not qualify as a reason for considering a split of the bidding area for the time being (cf. Section 4.1) and that the predominant development of the generation system is its transformation to higher shares of renewables, it becomes obvious that any future situation that would constitute a reason for splitting the bidding area would even more be associated with excessive renewable generation.

69 According to the "congestion evaluation" data collected by BNetzA, covering the period from April 2008 to September 2010

Figure 26. Frequency of congestion (daily resolution) of three German transmission lines in relation to maximum daily wind power infeed in Germany



Source: Consentec

In such a case, i.e. when generation from renewable sources is a major driver of congestion, the commercial effect of splitting the bidding area depends on the way this infeed is managed – prior to and after the split. In the following we discuss two options.

Case 1: Transmission priority to renewables

Support schemes for renewable generation are a common practice in Europe given the discrepancy between targets for the share of renewable generation on the one hand and their relatively high average total cost on the other hand. In Germany, the TSOs are obliged to buy power from renewable generators at a fixed infeed tariff, distribute it among themselves and sell it at the power exchange (EEX spot market).[70] The distribution step is a physical exchange of actual current infeed such that ultimately the TSOs share the infeed in equal ratios according to their regional load, irrespective of its actual geographical distribution. This way the physical burden of the prioritisation of renewables' infeed is distributed across the country. This is mirrored by the fact that the infeed tariff is financed by a country-wide equal levy on the end consumers' energy price.

70 This applies to the vast majority of renewables infeed. Specific rules and options allow deviating from this scheme, but they have only little relevance so far.

Given that Germany (plus Austria) is a single bidding area, the commercial effect of the above procedure is that the total infeed from renewables is sold at the spot market with practically no minimum price limit.[71] Generally speaking, the spot price is lower the higher the generation from renewables is, as renewable infeed replace conventional plants (or allow them to export, depending on the price level in adjacent bidding areas).

If the German-Austrian bidding area was split inside Germany, maintaining the concept of national renewables support and of sharing physical infeed on an equal basis would require granting priority to transmission of power from renewables across the newly emerging borders. As a result, the power market would start from a situation where from a commercial perspective the shares of renewable power are equal in all bidding areas of Germany and the transmission capacity across the internal borders would already be partly used up by the prioritised transmission of renewable power. This would very much resemble the current situation. In particular, there would not be an uneven physical distribution of low-priced generation from renewable sources among the new bidding areas. Consequently, there would be a lack of drivers of a substantial change in the commercial utilisation of the cross-border transmission capacities in the region.

Case 2: No transmission priority

One may argue that, whereas the concept of transmission priority across newly emerging borders allows for continuation of existing support schemes for renewables, such prioritisation constitutes some form of discrimination (vis-à-vis conventional power generation) and thus may not admissible under competition considerations.

In this case, all power from renewable sources would have to be offered in the bidding area where it is generated, and the market coupling algorithm of the spot market (rather than a precedence rule) would decide which bidding area it would be delivered to. As a consequence, at times with high renewables infeed the surplus bidding area may, depending on market prices in the neighbouring bidding areas and potential shifts in the interconnector capacities, export more to foreign bidding areas and less to the other national areas compared to a situation where from a commercial perspective a national distribution of renewables infeed is required and made possible by respective transmission precedence.

On the other hand a national support scheme for renewables as it is currently applied in Germany could no longer be executed under these conditions. For example, end consumers in the South would no longer benefit from wind power generation in the North (in terms of lower power market prices during strong

71 At times of extremely high infeed from renewables (negative) price limits may be introduced.

wind periods). Consequently, it would become illogical for them to pay the renewables levy and thereby indirectly subsidise the power price in foreign countries where the renewable energy would then be sold.

Conclusion on the network effect of market splitting Germany-Austria

In section 4.2.1 we showed that splitting the German-Austrian bidding area as such would not materially change the amount of available transmission capacity.

In situations where congestion is highly correlated with prioritised generation from renewable sources – as it is the case for the congested internal German lines – the commercial effect of splitting the bidding area would strongly depend on the way in which this prioritisation of renewable infeed is treated after the split.

In order to transform the existing concept of a national renewables support scheme to a constellation of split bidding areas, the *de facto* transmission priority within the joint bidding area would have to be transformed into an explicit priority access to transmission capacity across the newly introduced borders within Germany. As a consequence, the split would neither have a significant effect on the technical capacity nor on the commercial utilisation thereof. The market situation would very much resemble the *status quo*.

If priority access to transmission capacity across the new borders could not be granted, the commercial utilisation of transmission capacity may change, and so may the market result. Exports of renewable generation from surplus bidding areas to foreign areas may increase while the share of (imported plus locally generated) renewables in the other bidding areas (e.g. Southern Germany) may decrease. However, the present national renewables support scheme would have to be adapted to become compatible to such a situation, as it implicitly relies on a single German bidding area. Such adaptation would need to be in place before market splitting could take effect. This shows that a decision on splitting of bidding areas cannot be taken independently, but interferes with other processes and targets of energy policy.

4.3 Step 3 – Economic assessment

In the following we apply some aspects of the cost-benefit framework developed in Section 3.6 on the bidding zone Germany-Austria.

We note that the following discussion is an "as-if" cost-benefit analysis, we treat the bidding area Germany-Austria "as-if-there were a structural and sustained congestion".

The organisation of the analysis is as follows:

- In a first step, we define the **Status Quo** and **Market Splitting** for Germany-Austria.
- We assess the impact of Market Splitting on market concentration and highlight the main challenges and risks arising from market concentration.
- Based on the identified challenges and risks we discuss the impact of Market Splitting on static and dynamic efficiency.
- We also discuss potential transaction costs.

Within the analysis we mention other options – instead of market splitting – within the Status Quo, which can be used to tackle structural congestion taking into account new instruments introduced by the European 3rd Energy Package, e.g. Ten Year Network Development Plan.[72] We regard it as important and necessary in order to get a wider perspective in the current – perhaps too narrow – discussion on market splitting.

4.3.1 Definition – Status Quo and Market Splitting

Status Quo – Germany-Austria

Germany-Austria is currently organised as one bidding area. The main characteristics of the bidding area of relevance for the following discussion are:

- **Congestion management by cost-oriented redispatching** – Redispatched power plants are compensated according to their costs, where the appropriateness of costs is reviewed periodically.
- **No locational signals** – There are no locational signals from electricity prices due to the uniform price in the single bidding zone for generators and demand. Furthermore, other instruments for locational signals, e.g. local transmission tariffs or auctioning of generation sites, are also absent in Germany.[73]
- **Wholesale market** – There is one wholesale market for Germany-Austria with the power exchange EEX setting reference price for OTC electricity contracts and providing liquidity to the spot and forward market. There is no divergence between the price a participant pays or receives in the spot market and the price at which its financial contracts are settled at the EEX.

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72 In Section 2.2.3 we already mentioned an option how to improve the calculation of NTCs by introducing more dynamics.

73 This holds true for Austria, as well.

Hence, there is no financial risk (see Section 3.6.8) in the bidding area Germany-Austria with regard to the location of generation and physical delivery. As a consequence no hedging products for financial risk in relation to location of production or delivery are available.[74] The effective place of delivery for all forward contracts is the whole bidding area Germany-Austria.[75]

Market Splitting – Germany-Austria

According to ERGEG (2010) market splitting should take place along structural congestion. In Section 2.2.1 we identified one transmission line, *Remptendorf-Redwitz*, historically affected by congestion. Hence, for the sake of the analysis we define *Remptendorf-Redwitz* as the "as-if-structural congestion" and split the bidding zone into two bidding zones along *Remptendorf-Redwitz* (**Figure 27**). We obtain:[76]

- *North bidding zone* – consisting of the control area of 50HzT and the northern half of TenneT Germany. Due to the distribution of generation and load in Germany we would expect this to be the low-price area.
- *South bidding zone* – consisting of the control area of Amprion, EnBW and the southern half of TenneT Germany. Due to the distribution of generation and load in Germany we would expect this to be the high-price area.

In the following discussion we approximate the border of the North and South bidding area with the borders of the federal states in Germany, which comes close to the borders of the control areas. When calculating concentration ratios we assign the generation capacities according to the borders of the federal states in Germany. We note, that this simplification does not affect the conclusions from the following discussion (as there are only minor differences when allocating plants by federal states rather than the precise borders of the control areas).

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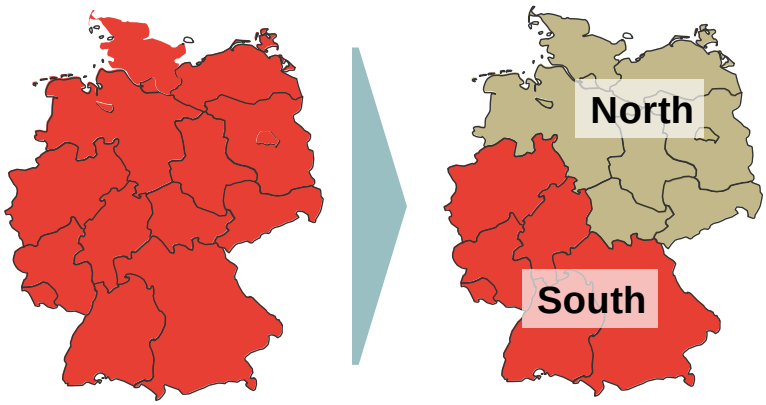
74 From October 2003 to the end of 2005 eSpreads, CfD-like contracts on the difference between day-ahead (system) prices for base- or peakload at the Energy Exchange Austria (EXAA) and European Energy Exchange (EEX), were listed at the EXAA, but discontinued due to insufficient trading activity.

75 Legally speaking it is the balancing zone of Amprion.

76 We exclude Austria in the following discussion. The exclusion has no effect on the conclusions.

Figure 27. Market Splitting of Germany (excl. Austria)[77]



Source: Frontier Economics/Consentec

We also make the following assumptions for the case of market splitting:

- **Congestion management by cost-oriented redispatching** – Both within the North and South bidding areas congestion management will be necessary in the future, in addition to market splitting. The method used will be cost-oriented redispatching, as currently applied.

- **Locational signals by electricity prices** – According to the "as-if" structural congestion we assume that congestion constraints between the two bidding areas will be binding frequently resulting in differences in electricity prices. This would send locational signals to market participants.

- **Wholesale market** – We assume that the wholesale market will be organised according to **Option 1** from Section 3.6.8. This means that the wholesale market will cover both the North and the South bidding area and the market operator will also quote a system price.

4.3.2 Market Splitting – The impact on Market concentration

Overview

Market splitting reduces the size of the bidding area. As a first step, we assess the impact on market concentration by calculating concentration ratios. Concentration ratios are a useful (though not sufficient) first indicator to assess the potential of market power and are commonly used by competition authorities. In order to evaluate whether a single player has a dominant market

77 Whereas, we approximate the border of the bidding zones with the borders of the federal states in Germany.

position competition authorities calculate the market share of the biggest undertaking (CR1). In order to explore the potential for joint dominance the market shares of the two (CR2) to five (CR5) biggest undertakings are calculated.

According to § 19 Abs. 3 German competition law a market dominant position of an undertaking is assumed if its market share (CR1) exceeds 30% in the relevant product and geographic market. Joint dominance is assumed for 2-3 undertakings (CR2 and CR3) if joint market shares exceed 50% and for 4-5 (CR4 and CR5) if joint market shares exceed 66%. The EU "Merger Guidelines" also suggest thresholds for dominant market positions. In merger cases a market share exceeding 50% is *per se* an indicator for market dominance. However, the EU Commission states, that market dominance can occur below a market share of 50%, as well.

In the following we calculate indicative concentration ratios for the North and South bidding zone[78] using installed capacities in the North and South bidding zone based on Platts data for July 2010, which include the current moratorium for nuclear power plant (closure of 8 nuclear stations). We assume no exchange between the bidding zones and only focus on the geographical market Germany[79]. For defining the relevant market we use two cases:

- *Frontier Economics Case* – generation market includes renewables; and
- *Bundeskartellamt Case* – generation market excludes renewables.

Resulting concentration ratios are then compared against those observed in:

- Status Quo; and
- those suggested in the competition act (GWB).

Concentration ratios higher than the Status Quo indicate an adverse effect of market splitting on competition.

Calculation of Market concentration ratios – Frontier Economics case

Based on the wider product market definition, including renewable, the concentration ratios in the Status Quo – Germany tend to be near or below critical thresholds defined in GWB. RWE has the highest market share based on installed capacities with (30%) followed by E.ON (14%) and Vattenfall (14%). CR3 and CR5 are above GWB thresholds (**Table 3**, **Figure 28**).

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78 We approximate the border of the bidding zones with the borders of the federal states in Germany.

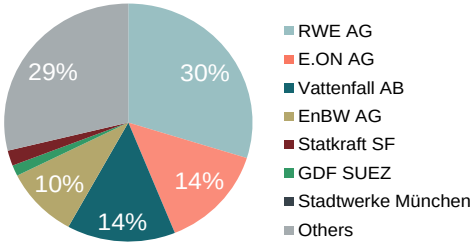
79 This will lead us to overestimate the concentration ratios because we neglect competition pressure from outside the bidding area that can arise up to the level of available transfer capacity from neighbouring bidding zones.

Table 3. Market concentration ratios 2010 – Frontier Economics case (with nuclear moratorium)

	GWB Thresholds	Status Quo	North Bidding Zone	South Bidding Zone
CR1	**30%**	30%	37%	42%
CR3	**50%**	58%	57%	72%
CR5	**66%**	69%	64%	75%

Source: Frontier Economics

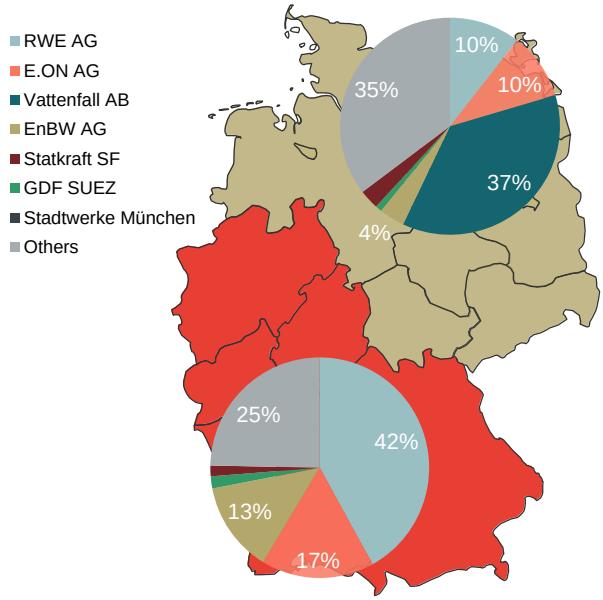
Figure 28. Market structure Status Quo Germany (Frontier Economics Case)



Source: Frontier Economics, Platts

Splitting Germany into two bidding areas raises concentration ratios especially in the South bidding area above critical GWB values (CR1: 42%; CR3: 72%; CR5: 75%). Moreover, it creates two regionally strong companies, with RWE (42%) in the South and Vattenfall (37%) in the North.

Figure 29. Market Structure North-/South Bidding area (Frontier Economics Case)



Source: Frontier Economics

The above indicative calculations show that concentration ratios in the North and South bidding areas increase compared to the Status Quo. Furthermore, even in the case of a wider market definition, including renewables, the concentration ratios rise above critical GWB thresholds.[80]

Calculation of Market concentration ratios – Bundeskartellamt case

In the *Bundeskartellamt Case* excluding renewables from the market definition the results are even more striking. Based on the product market definition excluding renewables the concentration ratios for the status quo are above critical GWB thresholds (**Table 4**, **Figure 31**).

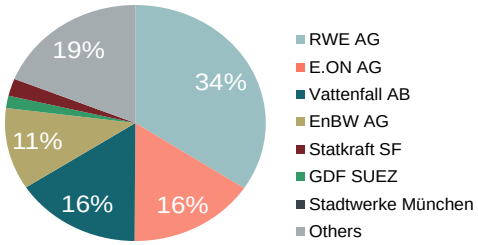
80 Including the possibility of import/exports tends to decrease concentration ratios, but the tendency still remains the same.

Table 4. Market concentration ratios 2010 – Bundeskartellamt case (with nuclear moratorium)

	GWB Thresholds	Status Quo	North Bidding Zone	South Bidding Zone
CR1	**30%**	34%	45%	46%
CR3	**50%**	66%	69%	79%
CR5	**66%**	79%	77%	82%

Source: Frontier Economics

Figure 30. Market structure Germany (Bundeskartellamt Case)

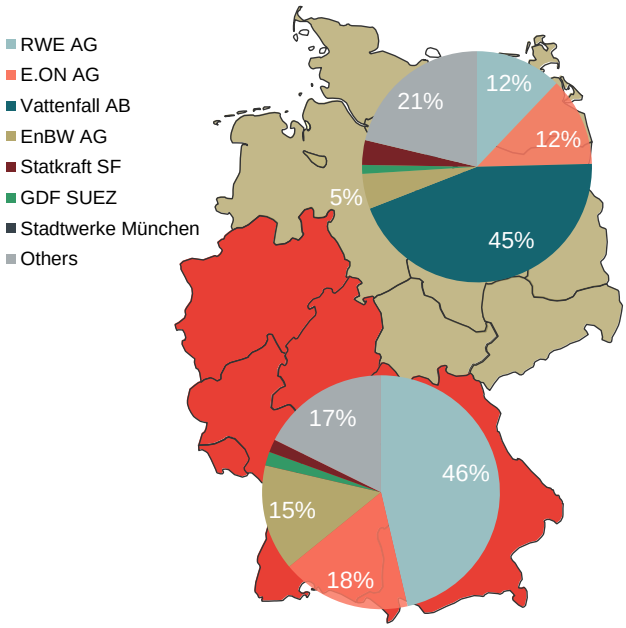


Source: Frontier Economics

Splitting Germany into two bidding areas further lifts concentration ratios. In both bidding zones CR1 increases substantially compared to the status quo to 45% respectively 46% nearly approaching the 50% threshold in the EU "Merger Guidelines". There are two regionally strong companies, with RWE (46%) in the South and Vattenfall (45%) in the North. [81]

81 Including the possibility of import/exports tends to decrease concentration ratios, but the tendency still remains the same.

Figure 31. Market Structure North-/South Bidding area (Bundeskartellamt Case)



Source: Frontier Economics

Market Splitting and Market concentration – Conclusions

Based on our indicative calculations, we find that Market Splitting will increase concentration ratios compared to the status quo especially if the transfer constraints on the newly created border were binding. Furthermore, two very strong market players would emerge in the North and South bidding areas, based on the *Bundeskartellamt* market definition with market share higher than 40%. In Section 2.4 we showed that the German Bundeskartellamt still has concerns about the competitiveness of the generation market for whole Germany. Hence, we would expect these concerns to increase in case of market splitting. Furthermore, market splitting contradicts the measures taken by the EU Commission and the German Bundeskartellamt in the past to reduce market concentration in the German electricity market.

Conclusion – Market concentration

Market Splitting increases market concentration within the newly created and smaller bidding areas as compared to the Status Quo. This implies an **adverse effect on market competition**.

4.3.3 Market Splitting and Status Quo – Disclosure of Market Power?

At first sight, market splitting would not change the physics in the network and thus would have no impact on existing "physical" market power. It would only make transparent "hidden" market power in the redispatch market by transferring it to the day-ahead market. However, this argument may not be valid for the German-Austria case. Due to the cost-oriented congestion management (redispatch) in the status quo there is effectively a control of market power in the existing redispatch "market", because the market is regulated. Furthermore, based on the results from Section 4.3.2 we expect that Market Splitting may translate a market power problem that is currently under regulatory control in the small redispatch "market" into the wider "transparent" day-ahead market.

Conclusion – Disclosure of Market Power

Market Splitting will not unveil market power in the redispatch "market", because redispatch is currently practically regulated (in the Status Quo). To the contrary**, Market Splitting may create a market power problem in the wider day-ahead market**.

4.3.4 Market Splitting – Static Efficiency

One drawback of the current cost-oriented congestion management regime is that it does not take into account short term input price variations of generators (as redispatch decisions are made based on standard assumptions on the operating costs of plant). Hence, least cost dispatch is not always guaranteed.

Market splitting along the structural congestion can include short term input price variations in the dispatch decision, if generators respond to them in their daily bids. Thus, total system costs may be lower in the North and South bidding areas compared to the status quo.

However, two caveats remain:

- From a technical point of view, the cost minimising congestion management requires a nodal approach, where the TSOs will redispatch the generation plants prioritised by their effect on the congested line. Market splitting does not take into account the location of the power plants within the bidding zone in determining the merit order. As a result more redispatched generation capacities may be necessary to relieve the congested line affecting the merit order in the North and South bidding areas compared to the status quo. This can impair least-cost dispatch.

- Competition determines if and to what extent generators will respond to short term fluctuation of input prices in their daily bids. As shown in Section 4.3.2 concentration ratios will increase in the North and South bidding zone compared to the Status Quo. Hence, the pressure from competition to

include short term fluctuations in the day-ahead bids will decrease. Higher market concentration increases the possibility to profitably exercise market power in the day-ahead wholesale market in the North and South bidding zone (if transfer capacity limits were binding). As a result, total system costs may increase, reducing the benefit from Market splitting compared to the status quo.

Conclusion – Static efficiency

Market Splitting allows generators and TSOs to take into account short term input price variations for those bids that correct for some congestion. This could lead to cost and price savings to the benefit of energy purchasers However, the timely price adjustment only works for plants "redispatched" through market splitting but not through traditional redispatch (which would remain cost based). There may be **two countervailing effects to the cost savings** due to a more timely price adjustment with market splitting:

- Higher costs if the **"redispatch" by market splitting is not optimal** (which it likely will not be);
- Higher costs due to increased **market concentration in the spot market**.

4.3.5 Market Splitting – Locational Signals for Power Plants

Given the current discussion on the future electricity production mix in Germany two trends are important:

- *Gas-fired power plants*[82] – their importance, as the most environmental friendly conventional thermal technology, will increase in the future.
- *Renewables* – their share, especially wind generation, will increase.

These trends raise two questions:

- Is there a need for locational signals for optimal locational decisions for generation technologies?
- To what extent can locational signals relieve congestion that would substitute for investments in transmission lines?

In the following we focus on conventional power plants. The discussion on renewables takes place in Section 4.3.6.

82 According to Section 3.6.3 we classify them as "Technologies with free location choice".

Locational signals – Is there a need?

In Frontier Economics/Consentec (2008)[83], we considered whether it would be beneficial to introduce locational grid fees to incentivise generation plants to locate closer to the load. This could be beneficial if it was cheaper to transport fuel to power stations than to transport electricity. We compared the electricity transportation costs from generation plants to distant load centres with the primary fuel transportation costs for generation plants located near the load, in order to assess the necessity for locational signals for the German electricity market. The main results can be summarised as follows:

- *Gas-fired power plants* – the transportation costs of electricity to load centres are higher than the gas transportation costs to plants located near load centres.
- *Coal-fired power plants along the Rhine* – the transportation costs of electricity to load centres are higher than the coal transportation costs to plants located near load centres.
- *Coal-fired power plants not along the Rhine* – the transportation costs of electricity to load centres are lower than the coal transportation costs to plants located near load centres.

The main results indicated the need and usefulness of locational signals for gas-fired power plants and coal-fired power plants along the Rhine.

Locational signals by electricity prices – Strength of price signals

Market Splitting would send locational signals to generators/investors, where to invest. The impact on generators' investments will depend on the (expected) prevailing level of price differences between the North and South bidding zone. Given the Italian experience of bidding areas and investment in gas-fired power plants, the impact of the price differences in the six bidding areas on locational decisions is not unambiguous (see Section 3.6.3, page 49).

Hence, market splitting will only send effective locational signals to investors, if the price differences between the North and South bidding areas are high during substantial hours in the year. Given the congestion in the German transmission network with so far only one line facing frequent congestion, it is unclear, if this condition is satisfied or will be satisfied in the near future.

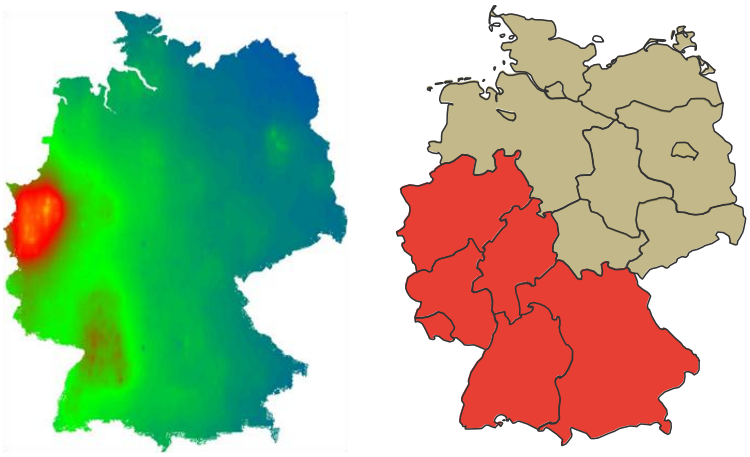
83 Frontier Economics/Consentec, *Notwendigkeit und Ausgestaltung geeigneter Anreize für eine verbrauchsnahe und bedarfsgerechte Errichtung neuer Kraftwerke*, Report for the Federal Ministry of Economics and Technology, 2008.

Locational Signals by electricity prices – precision of the signal

Market splitting sends *inter bidding area* locational signals by differing electricity prices. However, there are no *intra bidding area* locational signals from electricity prices. In order to optimise congestion relieving power plant the locational signals between bidding zones are not sufficient and more precise locational signals would be desirable.

Whether this is the case in Germany can be illustrated by comparing the load density in Germany with the North and South bidding areas (**Figure 32**). In the case of zonal locational electricity prices and the South bidding zone being the high-price zone, investors will be indifferent where to invest in the South bidding area. However, from a congestion point of view investments in the south-west of the South bidding zone, where load centres are situated, tend to have a bigger impact on congestion than in the south-east of this zone.

Figure 32. Approximated load density in Germany (red/yellow: high load density, blue: low load density)[84]



Source: Frontier Economics/Consentec

Hence, there is a strong case for supplementing the locational signals coming from zonal electricity prices with additional instruments.

One option would be to decrease the bidding area to the nodal level, i.e. using nodal electricity prices as locational signals. However, this approach has some main drawbacks, which we discuss in Section 3.6.3 (page 50) and Section 5.1.

Another option to supplement locational signals of Market Splitting is by transmission pricing, e.g. by Entry/Exit pricing. This is one approach suggested

84 We approximate the border of the bidding zones with the borders of the federal states in Germany.

in Frontier Economics/Consentec (2008) as one option of locational signal for Germany. Locational signals by transmission pricing have several advantages:

- long-run reliability of tariffs;
- low volatility of tariffs; and
- nodal signals become possible when desired.

However, locational signals based on transmission pricing can not only supplement plant locational signals from Market Splitting but can substitute it.

Hence, locational signals based on transmission pricing can be implemented in the Status Quo, reducing one disadvantage of the Status Quo – no locational signals – without changing the market design. Furthermore, there would be no effects on market liquidity, market concentration, existing IT systems, etc., in cases locational transmission tariffs were introduced. Locational transmission pricing, however, does not deal with short-term congestion (while Market Splitting does).[85]

Locational signals – Price volatility and flexible technologies

In Section 3.6.3 (p.47) we discussed the role of price volatility as an investment signal for flexible generation technologies, which are important to integrate volatile generation especially from wind power into the electricity system.

Market Splitting will create two bidding areas, where volatile generation currently has a substantial share in the generation mix in the North bidding area and will increase in the future (see Section 4.3.6). As a consequence, we would expect an increase in the price volatility due to the future generation mix in the North bidding area compared to the Status Quo. This will raise the attractiveness of the North bidding area for investors in flexible generation technologies and/or storage, who can profit from price spikes and volatility. This will ease the impact of renewables generation on the electricity system.

However, some important caveats remain with regard to this positive effect from Market Splitting.

- The price signal only works, if high price spikes in the spot market, which send the right signals for the profitability of flexible technologies, are allowed and accepted by regulators or competition authorities. However, there is a relationship between the acceptance of price spikes and market concentration in the spot market. The higher the market concentration the higher will be the probability that competition authorities suspect price

85 This may not be a problem, if the main issue is to provide locational signals in the medium and long term and not to address static dispatch decisions.

spikes are the result of abuse of market power. As shown in Section 4.3.2 the market concentration in the North bidding area will increase compared to the status quo. Thus, the probability that competition authorities will react on price spikes in the North bidding area will increase, irrespective of whether they result from market power or not.

- One possibility could be to introduce price caps for spot market prices in the North bidding area. Depending on the level of the price cap this may reduce or remove the profitability of plant investments. Investors will include the probability of regulatory actions in investment calculations, which may reduce the investment incentive from higher price volatility.

Another option to offer investors profit opportunities may be to change the redispatch regime in the Status Quo from a cost-oriented to a market-oriented system. In this case, the price volatility is transferred into the (nodal) redispatch market and investors can profit from price spikes, leading to revenues far exceeding current costs. Switching from a cost- to a market-based redispatch system may introduce a market power problem in the redispatch market. Compared to the market power problem in the spot market in the North bidding area this may be a smaller problem with less effect on overall price levels. However, it is unclear how the possibility of regional or nodal abuse of market power in the redispatch market feeds back into the bidding strategies of companies in the spot market.

Although price volatility in theory *can* send the right locational signals to investors, the question still remains if the exploitation of price volatility offers enough expected revenues to cover the higher cost of capital due to higher risks for investors. Or in other words, the question still remains if other more reliable long-term incentive systems implemented into the status quo, e.g. some kind of capacity payments for flexible generation, will give similar signals at lower risks and lower cost of capital.

Conclusion – Locational Signals for Power Plants

Market Splitting would introduce **regionally differentiated signals into the Germany-Austria** bidding area. The comparison of electricity and primary fuel transportation costs indicates the **need and usefulness of locational signals** for gas-fired power plants and coal-fired power plants along the Rhine. Furthermore, higher price volatility in the smaller North and South bidding area may send locational signals for flexible generation.

However, some **caveats** remain:

- It is unclear, if the **price signal** from Market Splitting is **locationally precise enough** to induce the appropriate choice of location.
- It is unclear, if the **price differences from Market Splitting based on**

the current congestion are high enough to induce effective locations choices.

- It is **unclear**, if generators can profit from price volatility **without regulatory interference**.

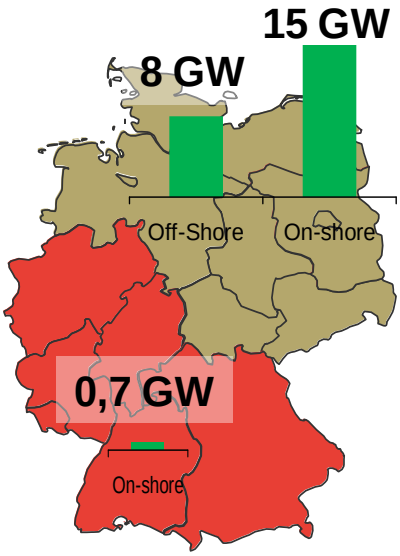
Furthermore, it is likely, that locational signals can also be introduced by other means, e.g. by locational transmission pricing, within the Status Quo which are at least as precise and reliable as the signals derived from Market Splitting.

4.3.6 Market Splitting – Locational Signals and Renewables

As discussed in Section 3.6.4 the impact of locational signals depends on the responsiveness of investors with different generation technologies on market prices. The responsiveness of investments into renewables tends to be – at best – restricted. To a large extent the reward for renewables comes from feed-in tariffs or other subsidy schemes, and is independent of market electricity prices.

In support of EC renewables targets Germany has set itself ambitious climate change and renewable targets by increasing the share from renewable energy on the total energy mix. The majority of wind generation expansion in Germany is expected to be off-shore and in coastal areas in the north of Germany (**Figure 33**). Assuming that the North bidding area tends to be the low-price zone, this implies that large investments decisions in generation in the future will not respond to locational signals from electricity prices due to Market Splitting. Market Splitting does not solve the problem of transporting the generated wind electricity to the load centres in the south.

Figure 33. Forecast Wind Capacity in Germany



Source: DENA

As discussed in the previous section, Market Splitting may ease the impact of wind generation by giving the right locational investment signals to flexible conventional generation.

However, in order to integrate the new volatile renewable production, especially wind, an expansion of the transmission grid is inevitable to transport electricity produced from wind to

- load centres inside the county; and
- storages, e.g. pump-storage-plants in the Alps, to overcome the time divergence between production and demand.

Conclusion – Locational Signals and Renewables

In order to integrate wind generation (with priority access) into the electricity system the **expansion of the transmission grid is inevitable**. Market Splitting or other incentive systems within the Status Quo can at the best ease the impact from more volatile generation on the use of the transmission network.

4.3.7 Market Splitting – Incentives for investments into transmission grid

In Germany there is a widespread consensus between politics, the public, academics and electricity companies that new transmission lines are necessary to especially integrate wind energy into the electricity system. For example, the

DENA I[86] study estimated that until 2015 Germany needed 850 km additional lines, and the DENA II[87] study estimated additional 3.600 km for the period 2015 to 2025.[88] Furthermore, previous studies for Germany have concluded that on a number of key routes, grid expansion and investment should be prioritised and is more economic than transporting primary fuels to power plants in loaded areas. On the European level the ten year development plan of ENTSO-E[89] includes investment needs until 2020 of 42,000 km, where 35,000 km are new lines and 7,000 km are upgrades for the whole of Europe. Furthermore, ENTSO-E expects that until 2020 more than 25 GW of new interconnectors are needed, with an increase for Germany of 6 GW.

Despite the widespread consensus on the necessity of new transmission lines the out turn investments are lagging behind. Only 80 km of the planned 460 km until 2010 from Dena-I have been installed. The reasons are manifold:

- frequent changes in the regulatory framework; and
- strong regional resistance that slows down planning procedures and investments.

In 2011 the German Ministry of Economic Affairs issued a proposal for a new law, which aims to expedite the approval process for new transmission lines.[90]

Status Quo – Regulated companies[91]

In the Status Quo, congestion constitutes costs for the transmission operators. The current regulatory system for transmission operators addresses grid investment cost incentives through at least two parallel mechanisms that may provide separate revenue streams to the investors:

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86 DENA, *Energiewirtschaftliche Planung für die Netzintegration von Windenergie in Deutschland an Land und Offshore bis zum Jahr 2020*, Deutsche Energie Agentur, 2005.

87 DENA, *dena-Netzstudie II – Integration erneuerbarer Energien in die deutsche Stromversorgung im Zeitraum 2015 – 2020 mit Ausblick 2025*, Deutsche Energie Agentur, 2010.

88 The concrete figures vary depending on the assumptions and modelling approaches of different studies – e.g. Dena-II and Consentec/r2b (2010), however not questioning the common conclusion that there is a significant demand for additional transmission lines as a prerequisite for accommodating the intended transformation of the generation mix towards high shares of renewables.

89 ENTSO-E, *ENTSO-E's Pilot Ten Year Network Development Plan*, Brussels, 2010.

90 See BMWI, *Eckpunktepapier für ein Netzausbaubeschleunigungsgesetz („NABEG") – Verfahrensvereinfachung, Akzeptanz, Investitionen*, 2011.

91 In the following we only focus on regulated companies and neglect merchant investors. We don't see much scope for market driven transmission investments inside the bidding zone Germany-Austria due to the current institutional setting and the meshed network.

- **Sharing mechanism for ancillary services** – The regulator sets targets for the costs for ancillary services, including congestion costs. If the company beats the target it can keep a fraction of the difference as an additional profit. If the target is not met, the company has to carry a fraction of the extra costs. Hence, companies have incentives to reduce congestion costs, where investments in the grid are one option to achieve this.

- **Investment budget** – The regulator provides investment budget for certain investments of transmission operators, including investments into extending the grid. Capital expenditures as part of the investment budget, are exempted from incentive regulation at least for some time and can be passed through into grid tariffs.

Market Splitting – Regulated companies

In case of Market Splitting congestion costs turn into congestion revenues. As already discussed, transmission operators worry less about high congestion revenues, even if they must pass them on to customers, than about high congestion costs, especially if the pass-through to customers is restricted by incentive mechanism. Hence the incentives from the current sharing mechanism for ancillary services, which is based on optimising congestion *costs* e.g. by grid investments, would be changed. Depending on the specific new regulatory design investment incentives would most likely be reduced, because the cost pressure from congestion are removed from the transmission operators.

Furthermore, Market Splitting may have additional dampening effects on investments:

- *Local resistance* – Market splitting makes transparent the potential winners and looser from a congestion relieving investment. This will increase the resistance of the losers in grid investments, amplifying existing public resistance.

- *Impact on authorities* – Market splitting may reduce the pressure on authorities to fasten up the permission procedure, because authorities may argue that market forces are still at work through some form of market based congestion management.

Conclusion – Incentives for investments into transmission grid

Market Splitting potentially has a **negative effect on the regulated TSO's incentives and the public acceptance for new transmission lines**, which would be required to fulfil environmental policy targets at least cost.

4.3.8 Market Splitting – Market Liquidity and impact on competition

We assume that in the case of market splitting the wholesale power exchange market will continue to cover the new North and South bidding areas. Hence, the size of the market overall will not change. However, some organisational changes are necessary, where the impact on overall market liquidity and products is not straightforward.

In the following we discuss some implications and possible risks for the:

- spot market;
- forward market; and
- hedging market.

Spot market

Higher market concentration on the spot market in the North and South bidding area (see Section 4.3.2) may have an impact on the ability to (profitably) manipulate the spot prices in the bidding area when congestion constraints are binding. This distorts on the one hand the spot prices in the respective bidding area. On the other hand strategic bidding in order to profit from local market power in the bidding area will feed into the virtual system spot price. Hence, the confidence in the system spot price as well as the regional price will decrease.

One effect of distorted prices may be that the costs of market participants to fine tune their positions in the spot market will increase, because they expect price increases due to market power. Another effect of distorted spot prices in general may be that market participants will search for other ways to sell and/or buy electricity by-passing the organised whole market at the power exchange.

Forward market

A spot system price which is used as the settlement price for forward contracts helps pooling market participants in the forward market. For example, a virtual PHELIX calculated by the EEX, based on the actual aggregated bid and offer curves under the assumption of no congestion between the bidding areas, can be used as the virtual spot system price for the North and South bidding area. One advantage would be that the impact on existing forward contracts on the EEX – with only financial delivery – is only limited, because the settlement price doesn't change. However, a problem is likely to arise in the case of forward OTC contracts with physical delivery.

However, the exercise of market power on the spot market will affect the forward market, as well. Again, this will distort the information conveyed by the forward price and reduces the confidence in the forward market.

Another drawback of the new *virtual* PHELIX may be that the confidence in this new reference price in general decreases, because market participants prefer a *real* price over a *virtual* one. Hence, this will spill-over to all market participants currently using the PHELIX as a reference, e.g. in price formulas, inside and outside the current EEX bidding area.

Hedging market

The main impact of Market Splitting will come from the introduction of a new trading risk (financial risk). The risk consists of the divergence between the price that a participant pays or receives in the North and South bidding area spot market and the price at which its financial contracts are settled – the *virtual* PHELIX.

This divergence between the price a participant pays or receives in the spot market and the price at which its financial contracts are settled occurs when:

- participants have entered into financial contracts with participants located in another bidding zone; and
- transmission constraints, that restrict flows on interconnectors between those bidding areas bind, cause the relevant spot price in the bidding zone to diverge from the system price.

Currently, this financial risk does not exist in the status quo. Although, there are international examples for dealing with this risk, Contracts for Differences and Financial Transmission Rights (see Section 3.6.8), the experiences are not persuasive.

We see hedging of the financial risk as the main challenge for the wholesale market if market splitting is introduced, where the outcome on market liquidity is uncertain. There are possible results, which can occur cumulatively:

- *New hedging products may emerge* – the demand from market participants in the North and South bidding area for hedging products indicates a profit opportunity, which may be grabbed by entrepreneurs offering new products;
- *New hedging products including high risk premium* – although the demand would exist there is a lack of counter parties, which could lead to low liquidity and high risk premiums for the hedging product;
- *Market participants bear the financial risk* – market participants bear the financial risk and price it into their calculations, if the difference between the *system* spot price and the bidding area spot price is stable or moves around a stable average; and
- *Market participants restrict their activities* – market participants may remove the financial risk, by restricting their activity only to one bidding area.

Due to the importance of the EEX forward market for market participants to hedge future positions, the impact of new financial risk on the hedging behaviour of market participants has to be carefully considered. Although, the additional risk is difficult to quantify, we would assume that the risk premium in the market in general will increase, which has an upside effect on electricity prices.

Conclusion – Market Liquidity

The **impact** of Market Splitting **on the overall market liquidity is ambiguous**. Market splitting will almost certainly not enhance liquidity, **at best be neutral to liquidity, but will more likely lower liquidity**.

Market splitting may also lead to distorted information efficiency of spot and forward prices in case of exercise of market power. Furthermore, market splitting introduces **new trading risk**, where the outcome on market participants is uncertain. The risk results from newly introduced energy price spreads between regions (e.g. where a supplier generator generates/buys in one zone and sells in another). **Such risks may be hedged in theory, but it is unclear whether liquidity will develop for respective hedging products.**

4.3.9 Transaction costs

Lead time

Due to the depth of the forward market the lead time to introduce market splitting should be at least three years. A shorter lead may be possible, however, this will have a negative effect on the market liquidity. Additionally, a lead time of at least three years means, that one has to take into account the planned transmission investments during this period and whether these investments will relieve the structural congestion (potentially making the introduction of market splitting obsolete).

However, it is worth mentioning that an adaption of the current market design will need a shorter lead time, if the impact on the wholesale market is minor. Thus, locational signals by transmission pricing or similar incentive systems could be introduced without a disruption to wider electricity trading within a shorter period.

Primary and secondary measures

International examples for changing the market design provide an indication of possible costs of introducing market-splitting in Germany. Cost estimates are

mainly available for the following projects[92] (one-off costs without annual additional costs):

- Implementation of NETA (UK): one-off cost up to 500 Mio. GBP for, e.g.
  - trading desk at energy traders;
  - system change (IT, software, etc.); and
  - settlement and renegotiation of contracts (Trading, supply).
- Implementation of BETTA (UK): one-off cost up to 45 Mio. GBP for, e.g.
  - system change (IT, software, etc.); and
  - definition of new market rules.
- Implementation All Ireland Electricity Market (Ireland): one-off cost up to 260 Mio. € for, e.g.
  - establishing market operator;
  - system change (IT, software, etc.); and
  - definition of new market rules.

Hence, we would assume that Market Splitting in Germany may result in costs at the high double-digit or lower three-digit million € level. The cost would be caused in particular by consultation on and coordination of new market rules, the renegotiation of existing electricity contracts, the reorganization of the control areas and the conversion of interfaces between market actors.

Furthermore, there may be additional costs which are difficult to quantify resulting from the uncertainty when changing an existing functioning market design, e.g. the impact on the EEX due to the new financial risk by Market Splitting. When considering the change in the market design of the bidding area Germany-Austria, one should not neglect the importance of this area for the European integration process (see Section 2.3).

Conclusion – Transaction costs

A regime shift to Market Splitting in Germany could result in **costs in the order of high double-digit or lower three-digit million € level**. Furthermore, there may be **additional costs which are difficult to quantify** resulting from the uncertainty when changing an existing functioning market design, e.g. the impact

92 Frontier Economics/Consentec, *Methodische Fragen bei der Bewirtschaftung innerdeutscher Engpässe im Übertragungsnetz (Energie)*, Untersuchung im Auftrag der Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen, 2008.

on the EEX when due to the new financial risk by Market Splitting.

4.3.10 Distributional effects

Market Splitting will create winners and losers. The winners will be:

- producers in the assumed high-price South bidding area; and
- consumers in the assumed low-price North bidding area.

Consequently, losers will be:

- producers in the assumed low-price North bidding area; and
- consumers in the assumed high-price South bidding area.

Hence, the introduction of Market Splitting will face particular resistance from politics and affected stakeholders, who are likely to loose from the new market design. From an economic point of view this is just a distributional effect with no impact on economic efficiency. However, public resistance may increase the "political" transaction costs substantially. It is likely that the losers will ask for other "political" compensations.

Market Splitting and lower prices in the North bidding area are driven by subsidised renewable. This may put to question the Germany wide renewables subsidy regime. A potential "political" compensation may be the reduction of the burden from the current German renewables subsidy regime for the customers in the South bidding area that would face higher electricity prices. This will reduce some benefits for the customers in the North bidding area. Another international distributional issue may be the export of cheap subsidised electricity to neighbouring countries, which may trigger a national political discussion on the German renewable subsidy regime.

Hence, Market Splitting may have a far reaching effect on different political issues.

Conclusion – Distributional effects

Market Splitting will have **substantial distributional effects**. It is likely that there will be a strong resistance from adversely affected stakeholders (conventional generators in low price areas, suppliers or consumers in high price areas) who will ask for "political" compensation. Market Splitting may make some **changes** to the **current nationwide subsidy scheme for renewables** inevitable.

4.3.11 European perspective

The analysis so far has been focussed on the effect of Market Splitting only on Germany and Austria, which is the main focus of the practical application of the

reference framework in this report. However, due to the importance of the German/Austrian electricity market for the integrated European electricity market we would also expect an impact on other European countries from splitting the bidding zone Germany/Austria. In the following we are summarising arguments already used in the discussion above and provide an indicative assessment from a European perspective.

Table 5. Market Splitting Germany/Austria – European perspective

Step	Topic	Effect – European perspective
2. Technical effect of splitting of bidding areas	Effect on transmission capacities	Market Splitting as such would not allow for an increase of transmission capacity. However, it may be used as an opportunity for neighbouring countries to re-negotiate the geographical distribution of NTCs. There is no clear tendency that the amount of available transmission capacity on any particular border will rise.
3. Economic assessment	Market Liquidity and impact on competition	Higher market concentration reduces the informational efficiency of prices. We expect an adverse effect on the EEX spot/forward price from higher concentration ratios, having an adverse effect on the EEX as the relevant reference price for either neighbouring European countries or European countries with a less developed electricity market. Market splitting will almost certainly not enhance liquidity, at best be neutral to liquidity, but will more likely lower liquidity. This will also have an impact on market participants which are currently using the EEX market instead of their local power exchanges to hedge their positions in their local markets, e.g. French and Dutch traders.
3. Economic assessment	Incentives for investments into transmission grid	Market Splitting tends to have a delaying effect on the extension of the transmission network in Germany, because the problem of congestion may be seen as already being solved by a market mechanism. Due to the size of the German market and its geographical location in the centre of Europe on the hand, and the meshed transmission system in Europe on the other hand, a delay of transmission projects in Germany will have an adverse effect on transmission projects in neighbouring countries.
3. Economic assessment	Integration of Renewables in Europe	The integration of renewables in Europe is based on a strong European transmission grid. Any measures reducing the incentives for grid expansion, e.g. a Market Splitting of Germany/Austria (see above), endanger the integration of intermittent and/or remote power generation (e.g. coastal wind parks) into the European power system, which are necessary for a cost-efficient transformation of the power system to more renewable generation.
3. Economic assessment	European market integration	Historically, every political and economic measure was targeted on enlarging the European electricity market, also to reduce market concentration. Market Splitting tends to reverse

	this process by decreasing the market, and should only be used if no other measures, e.g. grid expansion, are available to solve congestion in a short-term and medium-term perspective.

Source: Frontier/Consentec

5 Congestion management – Up- and Downsizing

In this section we briefly discuss two options for the above mentioned market design which can be seen as a variant of the regimes discussed so far:

- **Nodal pricing** – Extreme form of market splitting.
- **Enlargement of bidding areas** – Integrating currently market coupled bidding areas into one bidding area.

5.1 Nodal pricing

Nodal pricing can be interpreted as the most extreme form of market splitting, where each node in the network represents one bidding area. Hence, many of the arguments from the previous sections are also relevant for the discussion of nodal pricing (we will refer to the respective sections in the following discussion), although some new arguments also come into play.

5.1.1 Static efficiency of nodal pricing

Nodal pricing fundamentally involves localised dispatch and spot market settlement of all generation participants. That is, whether or not a particular generator is dispatched (selected to run or not run as the case may be) and the price it receives for electricity is determined according to local (nodal) market and network conditions.

The motivation for such localised dispatch and settlement is to simultaneously achieve two economic objectives:

- *Dispatch Efficiency*: Minimise the cost of generating electricity to meet demand or "load" by dispatching the least-cost set of available generators possible given various power system constraints – referred to as least-cost security-constrained dispatch; and
- *Cost-reflective nodal prices*: Produce the instantaneous price of electricity at every "node" in the system that reflects the instantaneous short-run marginal cost (SRMC) of serving one incremental unit of load at that location. This price is referred to as the nodal price for that location.

As noted above, generators in bid-based, transmission-constrained nodal markets are typically dispatched if and when their offers lie below their local nodal price. Where generators are pure price-takers (i.e. they cannot exercise even transient market power) dispatch on this basis is consistent with the minimisation of resource costs in meeting demand, because generators are offering to supply

electricity at a price below or equal to the value of electricity at that location (as indicated by the local nodal price). In this sense nodal pricing is superior to market splitting as it ensures better locally targeted corrective actions when congestion arises.[93]

However, the assumption of price taking behaviour at the nodal level is very strong, and may not hold at many nodes in the network, especially when congestion does arise. The problem of market power under nodal pricing may be magnified compared to market splitting (see Section 3.6.7, 4.3.2 and 4.3.4). This may countervail the static efficiency of nodal pricing.[94]

Hence, under nodal pricing detailed market power mitigation measures are necessary at each node to monitor potential abuse of a dominant market position. For example, the PJM (Pennsylvania-New Jersey-Maryland) market introduced:

- price cap for maximum bids of $1,000/MWh; and
- "three pivotal supplier" test[95] to identify local market power in the day-ahead energy market since 2006.

The significant role of market power mitigation measures in the North-east United States markets should be borne in mind when drawing inferences about the competitive performance of these markets and the potential application to European market, where competition policy is much more "light-handed".

5.1.2 Dynamic efficiency of nodal pricing[96]

Investments in power plants

Market splitting provides locational signals by differences in electricity prices between the bidding areas. A more granular pricing structure, such as nodal

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93 However, the results from comparing welfare for nodal pricing and zonal/uniform pricing is not straightforward and depends on the underlying assumptions. For example, in Weigt, et al (2010) there is only a minor difference in welfare between nodal, zonal and uniform pricing in Germany based on transmission expansion scenarios for 2015.

94 This point is often excluded when comparing the welfare effect of nodal pricing with zonal or uniform pricing, which may tend to overestimate the advantage of nodal pricing (see Climate Policy Initiative, *Renewable Electric Energy Integration: Quantifying the Value of Design of Markets for International Transmission Capacity*, Smart Power Market Project, 2011).

95 The three pivotal supplier test measures the degree to which the supply from three generation suppliers is required in order to meet the demand to relieve a constraint. Two key variables in the analysis are the demand and the supply. For a detailed description of the "Three pivotal supplier" test we refer to: Monitoring Analytics, *State of the Market Report for PJM 2009, Volume 2: Detailed Analysis,* Appendix L (583ff), Independent Market Monitor for PJM, 2010.

96 Dynamic efficiency is often excluded when illustrating the advantages of nodal pricing (see again Climate Policy Initiative, *Renewable Electric Energy Integration: Quantifying the Value of Design of Markets for International Transmission Capacity*, Smart Power Market Project, 2011).

pricing, would provide even more refined locational signals to investors in new generation. Other things being equal (and assuming perfect foresight), one would expect electricity investors to make more locationally efficient decisions when faced with these more refined signals.

However, there are some caveats to this argument, which we already discussed in Section 3.6.3 and 4.3.5. The caveats are related to the lack of long-run reliability (and lack of certainty of prices even if the regime were otherwise stable) of the price signal, which may prevent investors from appropriately responding to the price signal. In particular, the problem of price volatility and the lack of long-term reliability at nodal level induced PJM to supplement the short-term Day-ahead energy market with a more long-run stable capacity market (see Section 3.6.3).

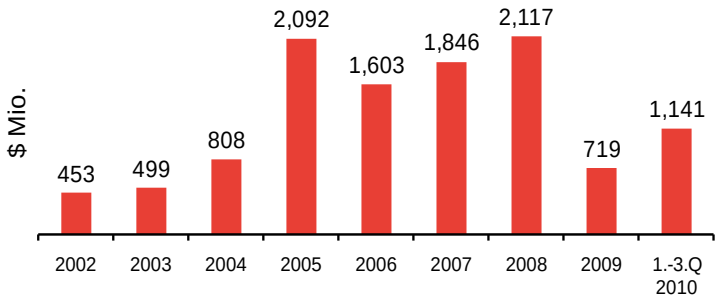
There is another point worth noting as to the relationship between the day-ahead market and the capacity market at PJM, which relates to market power. In the day-ahead energy market at PJM energy prices are capped by a maximum price. The relatively low energy market price caps reduce the potential payoff – and hence incentives – for generators with transient market power to exercise that power in the day-ahead market. Hence, there are only small indications for abuse of market power in the day-ahead energy market. However, there are concerns that the market power problem has been shifted to the uncapped capacity market.

Investments in transmission lines

Even in the case of a significant increase in congestion costs over time there are no guarantees for investments in the transmission grid. This can be illustrated by the PJM market which uses nodal pricing. Congestion management costs amounted to between 3% and 9% of total PJM revenues in the period 2002-2010. In this period absolute congestion costs more than doubled. However, there were no substantial investments from TSOs or merchant transmission investments in the PJM area.[97]

97 „In 2004, Paul Joskow noted that PJM had been reluctant to commission new transmission investment beyond what was required to meet generator connection or 'reliability' requirements. He also noted that the expectation that 'economic' investments would be made on a merchant basis had not come to fruition at that time." (Frontier Economics, 2009: 38)

Figure 34. Congestion costs PJM (2002-2010)



Source: Monitoring analytics

Subsequently, PJM has increased its focus on investments beyond generator connection and reliability requirements, as evidenced by the first regional transmission plan. As part of the plan, PJM authorised the development of $1.3 billion in upgrades to maintain grid reliability until 2011, which is expected to reduce congestion costs by $200-300 million per annum. PJM has also directed additional studies and evaluation of ten significant grid investment proposals worth $10 billion for the period up to 2021, many of which seek to serve the relatively congested eastern half of PJM.

5.1.3 Market concentration and Market liquidity under nodal pricing

As already discussed, nodal pricing in practice is accompanied by new measures to cope with market power in order to prevent the abuse of a dominant market position at the nodes. This may countervail the static efficiency properties of nodal pricing.

As for the impact of nodal pricing on market liquidity we refer to the discussion in Section 3.6.8. In electricity markets with nodal pricing, trading hubs where nodes are combined are established in order to gather enough market participants in the wholesale market. The issue of financial trading risk increases compared to market splitting, due to the larger local fragmentation of energy prices. CfDs or FTRs are necessary for each node for hedging purposes.[98]

5.1.4 Transaction costs under nodal pricing

Compared to market splitting, nodal pricing implies a much more far reaching change in the market design, which also makes necessary changes in the

[98] The potentially adverse welfare effect of new financial trading risk from nodal pricing compared to one bidding area is quite difficult to calculate and quantify. This difficulty is comparable with the modelling of the effect of market power in case of nodal pricing. However, one has to keep these effects – at least in qualitative terms – in mind when evaluating nodal pricing.

governance of the market by establishing an independent system operator. Hence, we expect high transaction costs for the implementation of nodal pricing. Especially, the transaction costs for market participants due to the new market design, e.g. rephrasing of the delivery terms in the contract, are uncertain and unclear.[99]

5.2 Enlargement of bidding areas

Instead of splitting one bidding area, one may also consider enlarging bidding areas, e.g. by combining different countries into one bidding area. This may be much more in line with the principles of an integrated European electricity market. In the following we discuss some issues of transforming several bidding areas into one bidding area.

As a preliminary step, we may use the criterion of "structural congestion" between two bidding areas in order to assess the possibility of merging the bidding areas. Lack of price convergence between the bidding areas may also be an indicator for the existence and severity of "structural congestion".

5.2.1 Static efficiency of enlarging bidding areas

The static efficiency of the enlarged bidding area depends on the amount of redispatch in the existing smaller bidding areas and the newly created bigger bidding area. In case congestion management is conducted through cost-based redispatch when widening bidding areas, more generators may be ultimately dispatched not according to their market based bids but to interventions by the TSOs. This would tend to increase the problem that cost-oriented congestion

99 Climate Policy Initiative (2011: 23-24), who are in favour of nodal pricing, lists further concerns: "**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 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."

management would not reflect short term input price variations and – on average – lead to higher cost of redispatch.

However, enlarging the bidding area allows for the optimisation of nodal redispatch of power plants over a larger area, which may increase the technical effectiveness of congestion management. For example, it may be possible to draw on cheaper power plants when redispatch occurs over a wider area to relieve a congested line.

By extending the bidding area coupled with cost-oriented congestion management the market concentration on the spot market will decrease. Lower market concentration reduces the potential for abuse of market power, which may lead to higher static efficiency because withholding of capacity is not a profitable strategy.

5.2.2 Dynamic efficiency of enlarging bidding areas

Investments in power plants

Extending the bidding area reduces the locational signals from electricity prices for investments in generation. If there are economic benefits from locational signals, e.g. the transportation costs of electricity are higher than the primary fuel transportation costs, enlarging bidding areas should be supplemented by additional locational signals, e.g. locational transmission pricings or auctioning of plant sites.

Investments in transmission lines

In cases where reinforcement of the transmission grid is economically efficient, market splitting may have the tendency to create a dampening effect on network investments, as we have discussed in Section 3.6.6. Consequently, an enlargement of bidding areas could strengthen network investment incentives. Of course, such enlargement is reaching its limits when operational security is compromised as TSOs start to face problems of too extensive curative congestion management (which would anyway coincide with an increased significance of the above mentioned drawback of cost-oriented congestion management in terms of static efficiency). But between keeping with the present bidding area structure for historical reasons and implementing a pan-European "copper plate" approach (i.e. a single bidding area) there could be room for case-by-case enlargement of bidding areas, thereby keeping the grid manageable while strengthening network investment incentives.

5.2.3 Market concentration and market liquidity in enlarged bidding areas

Extending bidding areas will have a positive effect on:

- *market concentration* – concentration ratios are likely to decrease; and

- *market liquidity* – increasing the size of the bidding area may attract further market participants.

5.2.4 Transaction costs of enlarging bidding areas

We would expect the transaction costs of enlarging bidding areas to be significantly lower compared to the case of market splitting, in particular if the enlargement takes place by completely merging two or more areas. For example,

- legacy contracts would not have to be adapted as their reference point of delivery (one of the bidding areas that get merged) continues to exist;
- market participants active in one bidding area would not have to set up a cross-border business, but rather get access to a larger potential customer base still within their single bidding area;
- no decision on a market design for newly emerging borders would be necessary; and
- existing renewables support scheme would continue to fit into the market design.

Further changes would be optional, i.e. could be implemented without time pressure, as opposed to market splitting where such changes would have to be synchronised with the change of the bidding area structure. This includes the merger of balancing areas or the adjustment of IT systems.

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