Economic efficiency analysis of introducing smaller bidding zones

Study for

European Energy Exchange AG

Augustusplatz 9

D-04109 Leipzig, Germany

EPEX SPOT SE

5 Boulevard Montmartre

75002 Paris, France

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Consentec GmbH

Grüner Weg 1
D-52070 Aachen

Tel. +49. 241. 93836-0
Fax +49. 241. 93836-15
E-Mail info@consentec.de

www.consentec.de

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Abbreviations

CACM	Capacity Allocation and Congestion Management
CfD	Contract for Difference
NTC	Net Transfer Capacity
RES	Renewable Energy Sources
TSO	Transmission System Operator

Executive Summary

International wholesale power trading in Europe is based on a so-called zonal approach, where power is a homogeneous product inside each bidding zone, while power exchange between bidding zones is limited in terms of its amount and administered by congestion management processes. In most countries, the bidding zones' borders coincide with national borders. Notable exceptions are Germany and Austria on the one hand, which form a joint bidding zone, and Norway, Sweden, Denmark and Italy on the other hand, which are split into two or more bidding zones, respectively.

In recent years, a vivid debate has emerged on whether modifications of the existing bidding zone structure would contribute to reaching the goals of the Internal Electricity Market such as competitive prices, efficient use of infrastructure and provision of economic signals for the efficient development of power supply. The European Commission's Regulation on Capacity Allocation and Congestion Management (CACM, going through scrutiny from the European Parliament and Council) stipulates a regular review and, potentially, modification, of the bidding zone configuration.

Several studies and position papers on this issue have been published. Some of these argue that modified, usually smaller, bidding zones would yield an increase of static and/or dynamic efficiency of power supply. This is often done by considering ideal market conditions and assessing optimal generation dispatch (so-called market simulation). Aspects that are hard to quantify, such as market power or liquidity, are often neglected or estimated to have some negative economic impact, yet being overcompensated by the static/dynamic efficiency gains.

On this backdrop, the objective of this study is to demonstrate how a refined quantitative simulation can contribute to a comprehensive, balanced assessment of introducing smaller bidding zones. The focus of the analysis is on the question to which extent a transition to smaller bidding zones has a positive effect on static and dynamic efficiency when realistic conditions such as uncertainties are taken into consideration. These new aspects of quantitative welfare assessment are embedded in a more general discussion on the efficiency of smaller bidding zones, which partly draws upon our previous work on the matter (in particular, studies for the German federal regulatory authority and the Central Western European Market Parties Platform).

The study shows that some of the idealistic assumptions under which smaller bidding zones are sometimes believed to yield welfare benefits are wrong. A refined application of numerical

simulations of scheduled generation and re-dispatch has been undertaken, with an emphasis on uncertainties. In particular, uncertainties regarding the amount of commercial transmission capacity on newly introduced bidding zone borders and uncertainties regarding the temporal course of network expansion have been investigated (fig. 1).

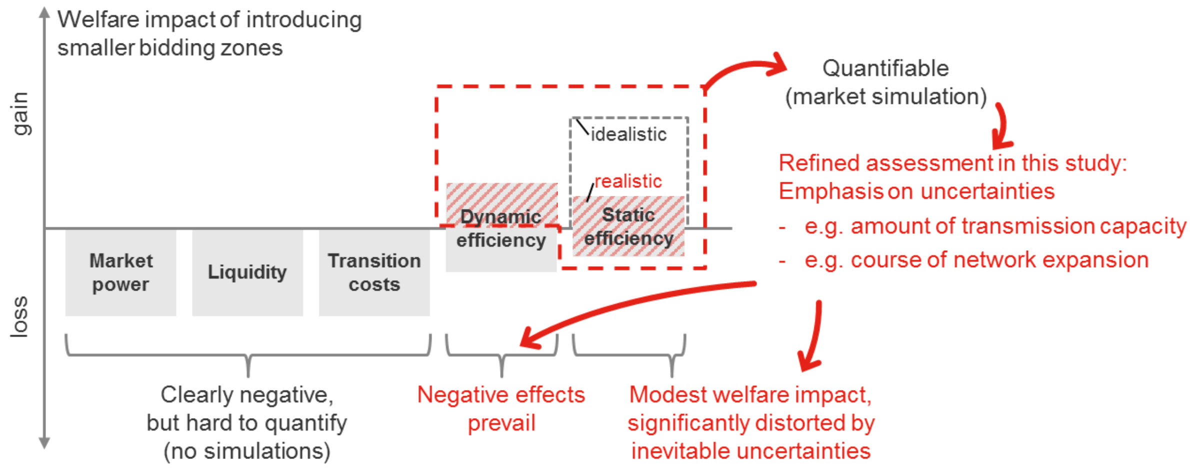

Fig. 1: Consequences of introducing smaller bidding zones on various welfare aspects, and (in red) focus and outcome of numerical assessment in this study

- The results indicate that the impact of downsizing bidding zones on **static efficiency** is relatively modest, with unclear sign. This is due to the two main effects: Firstly, changes of scheduled dispatch costs (efficiency of zonal market) and of re-dispatch costs largely level out each other. Secondly, introducing smaller bidding zones does not entirely remove the need for re-dispatch, and it can even give rise to new congestion inside the smaller zones, which locally increase re-dispatch costs.
- Regarding **dynamic efficiency**:
  - **Network expansion** affects the suitability of bidding zone configurations. The numerical assessment shows that the uncertain timing of network expansion reduces the efficiency of re-configuring the bidding zones, because there is a strong risk that network development and bidding zone configurations will be out of sync. This finding from the numerical assessment adds to a set of qualitative arguments why the dynamic efficiency of introducing smaller bidding zones tends to be negative.

 - **Investment incentives with respect to network expansion** are reduced by introducing smaller bidding zones. Smaller zones can be understood as a means to administer congestion, thereby avoiding the need to expand the network, although this may be more efficient. In larger bidding zones, there is a clear incentive to expand the network in order to reduce the operational and cost burden of re-dispatch.
 - Zonal price differences provide only weak **incentives for efficiently locating generation and load**. Moreover, alternative measures exist to achieve this, if desired.
 - Re-configuring bidding zones would yield significant **transition costs**[1], since numerous market and operational processes would be affected. Introducing smaller bidding zones would yield higher transition costs than merging of existing bidding zones.

- Smaller bidding zones tend to reduce liquidity and increase market power issues, which would result in a welfare loss. Efficient management of the transmission capacity between the bidding zones, i.e. capacity allocation and provision of financial hedging instruments, cannot avoid these effects: The purpose of re-configuring bidding zones is to impose restrictions of power transfer between these zones on the market participants, and this is the fundamental reason why liquidity and market power are affected in a negative way.

The above findings can be summarized by the conclusion that under realistic conditions (in particular accounting for uncertainties), the introduction of smaller bidding zones is unlikely to yield a positive total welfare impact.

We would like to note that the above conclusions are drawn under the condition that, in order to accommodate the politically desired transformation of the power system towards carbon-neutrality, sufficient network investment will be realised in terms of time and quantity. As we have shown in the analysis of dynamic efficiency, large and stable bidding zones help to stipulate network investment. But if endeavours for (efficient) network investment are not successful within the next years, introducing smaller – but stable – bidding zones might become necessary as last resort. This is because if the demand for curative congestion management (e.g. re-dispatch) became excessive, network security would be put at risk. Moreover, market based processes would then only account for an ever dwindling share of the final outturn dispatch.

1 Sometimes these are summarised under transaction costs. The term transition costs is used here in order to clarify that one-off costs of migrating to a new bidding zone structure are meant.

However, such formation of smaller bidding zones as last resort would not yield higher welfare, but make the transformation of the power system towards carbon-neutrality much more expensive: The development of renewable power sources would have to be adapted in a cost-increasing manner – more even geographic spread, less off-shore, more decentralized (PV) capacity, more total installed capacity for same energy production (due to more frequent curtailment of infeed) –, and the power market would operate with lower efficiency.

1 Background and scope of the study

International wholesale power trading in Europe is based on a so-called zonal approach, where power is a homogeneous product inside each bidding zone, while power exchange between bidding zones is limited in terms of its amount and administered by congestion management processes. In most countries, the bidding zones' borders coincide with national borders. Notable exceptions are Germany and Austria on the one hand, which form a joint bidding zone, and Norway, Sweden, Denmark and Italy on the other hand, which are split into two or more bidding zones, respectively.

In recent years, a vivid debate has emerged on whether modifications of the existing bidding zone structure would contribute to reaching the goals of the Internal Electricity Market such as competitive prices, efficient use of infrastructure and provision of economic signals for the efficient development of power supply. The European Commission's Regulation on Capacity Allocation and Congestion Management (CACM, going through scrutiny from the European Parliament and Council) stipulates a regular review and, potentially, modification, of the bidding zone configuration [1].

Several studies and position papers on this issue have been published. Some of these argue that modified, usually smaller, bidding zones would yield an increase of static and/or dynamic efficiency of power supply. This is often done by considering ideal market conditions and assessing optimal generation dispatch (so-called market simulation). Aspects that are hard to quantify, such as market power or liquidity, are often neglected or estimated to have some negative economic impact, yet being overcompensated by the static/dynamic efficiency gains.

On this backdrop, the objective of this study is to demonstrate how a refined quantitative simulation can contribute to a comprehensive, balanced assessment of introducing smaller bidding zones. The focus of the analysis is on the question to which extent a transition to smaller bidding zones has a positive effect on static and dynamic efficiency when realistic conditions such as uncertainties are taken into consideration. These new aspects of quantitative welfare assessment are embedded in a more general discussion on the efficiency of smaller bidding zones, which partly draws upon our previous work on the matter (in particular, studies for the German Federal Network Agency and the Central Western European Market Parties Platform [2, 4]).

The remainder of this report is structured as follows: In chapter 2 we describe the methodical approach, distinguishing between qualitative and quantitative parts. Chapter 3 provides an assessment of static and dynamic efficiency of introducing smaller bidding zones. It is this chapter to which the refined quantitative assessment contributes. Chapter 4 gives a concise overview of the impact of smaller bidding zones on liquidity and market power. Chapter 5 summarizes our findings.

2 Methodical approach

2.1 Overview

The configuration of bidding zones is one degree of freedom in the wider context of congestion management. The objective of congestion management is to increase pan-European social welfare.[1] Efficiency is often used as a synonym to welfare in this context.[2] Changing the configuration of bidding zones would affect several aspects of efficiency, such as

- Liquidity
- Market power
- Static efficiency
- Dynamic efficiency

In principle, these aspects are of equal importance when assessing the overall welfare effect of introducing smaller bidding zones. Therefore, we will touch upon all of them in this study, albeit with different levels of intensity.

2.2 Qualitative assessment of liquidity and market power

There are no numerical models for quantifying the impact of a bidding zone re-configuration on the level of liquidity and the extent of market power, let alone their subsequent impact on social welfare. Therefore, we will discuss these aspects on a qualitative basis. We will do this in a concise way and mostly draw upon previous work on the matter, given the fact that this does not appear to be the main field of disagreement among stakeholders in the public debate.

1 Cf. [1], Article 4(2)

2 Cf. e.g. [1], Recital (23): “Bidding zones will be defined to ensure efficient congestion management and overall market efficiency.”

2.3 Primary focus on quantitative assessment of static and dynamic efficiency

The focus of the study is on the quantitative assessment of static efficiency and of parts of dynamic efficiency. Further aspects of dynamic efficiency will be covered by qualitative considerations.

The quantitative assessment approach is as follows:

- Standard-type core models – A common analysis technique for large scale (international) power systems is the so-called market simulation. It serves to determine a plausible market outcome by determining the least cost dispatch for supplying (inelastic) demand. This is based on certain idealising assumptions, such as an atomistic market structure, rational behaviour, cost-based pricing, etc. Since the configuration of bidding zones relates to the interface between market and network, the analysis method is complemented by a re-dispatching simulation. The interaction between these models and their relationship to real market phases are explained in the course of the static efficiency assessment (section 3.1).
- Refined application of the core models by means of scenarios – While making assumptions is, by principle, indispensable when designing simulation models, it is important to bear in mind the limitations of one's models. An important property of market simulation models is that they are based on perfect foresight. This means that they make optimal use of the given set of framework conditions, including the existing generation park, network infrastructure, configuration of bidding zones, etc. By interpreting the results of such models as is, one would implicitly assume that all these conditions were perfectly known in advance. Even more importantly, one would implicitly assume that these conditions would coincide exactly in the way they are modelled. This would effectively ignore all uncertainties of system development.

  In order to avoid such over-interpretation of idealistic model results, we compare scenarios where certain aspects of the framework conditions are varied. This allows to consider deviations from some ideal development path (e.g. a delay of network expansion projects, uncertainty of transmission capacity in the day-ahead time horizon) and, given that such deviations are generally likely to happen, draw conclusions from a more realistic viewpoint.
- Generic assessment – On the one hand, numerical models require modelling concrete situations. On the other hand, the purpose of this study is not to answer the question if some

particular re-configuration of bidding zones would be efficient. Therefore, we interpret the simulation results in a prudent way, trying to obtain generalized, methodical findings. This also implies that the above mentioned scenarios are set up as exemplary, possible developments, but not meant to cover any concrete (share of a) bandwidth of uncertainties.

The focus of the numerical assessment is on overall efficiency (within the system boundaries of the models). Nevertheless, the models also allow to analyses distributional effects. Although this, should, according to the Regulation on CACM[3], not be part of the decision making on bidding zone structures, we perform some analysis of distributional effects in order to relate them to the total (static) efficiency effects.

[3] Cf. [1], Article 32

3 Static and dynamic efficiency

This chapter deals with the impact of downsizing bidding zones on static and dynamic efficiency. The assessment comprises qualitative considerations and quantitative analysis. We would like to recall that static and dynamic efficiency only account for a part of overall welfare, which forms the basis to comprehensively assess the efficiency of bidding zone configurations (cf. section 2.1). Further welfare aspects include liquidity and market power, which are discussed in chapter 4.

3.1 Static efficiency

3.1.1 Welfare measure and assessment method

Static efficiency is the efficiency of supplying power demand under constant framework conditions, i.e. for a pre-defined set-up of generation and transmission system, bidding zones, transmission capacities, etc. Under the assumption of inelastic demand (which is reasonably well fulfilled for the time being) the relevant measure of welfare for this purpose is the variable cost of power supply.

Power supply is organized by means of several market stages with successively shorter planning horizons. Nevertheless, the variable costs of power supply only depend on the final outturn dispatch. Our approach for determining the final outturn dispatch and its respective costs consists of two simulation stages:[4]

- Scheduled dispatch simulation – Assuming rational behaviour of all market participants (e.g. cost based pricing) a plausible market outcome can be simulated by determining the least cost dispatch for supplying (inelastic) demand. We apply a self-developed market simulation tool for this purpose. This model calculates the cost-minimal dispatch of the conventional thermal and hydro power plants for given demand and RES generation scenario. Hence, this approach is based on the assumption that the real market outcome is at least close to the cost-optimal generation dispatch. The optimisation model calculates the unit commitment in an hourly time pattern for a full year in closed form and considers all relevant technical (in particular also inter-temporal) and economic constraints and parameters.

[4] More information on the simulation models can be found in the annex.

Such are costs for fuel, CO_2 emissions and – for the dispatch of hydro power plants – the interconnections between the reservoirs of the power plants and the distribution of the limited available amount of water as well as the natural inflow to the reservoirs. Furthermore, cross-border transmission restrictions between the assumed bidding zones defined by NTC values are considered in the market simulation.

- Re-dispatch simulation – In order to determine whether the scheduled dispatch leads to a need for re-dispatch, the hourly results of the market simulation, each representing the load and generation situation for the specific hour, are inserted in a load flow model of the European transmission grid. We make use of a load flow model of the continental European transmission system that we derived from public information sources and that hence is free from third parties' intellectual property rights. Despite natural limitations due to the origin of the model, it has been proven suitably accurate for such types of investigation. Based on these hourly network models load flow and (n-1) contingency calculations are performed. This yields an hourly pattern of the load flow distribution over the different elements of the transmission grid. If one or more network elements are overloaded as a consequence of scheduled dispatch, re-dispatching measures are determined for the respective hour(s) in order to make sure that the final outturn dispatch does not lead to overloading of the network.

  Re-dispatch is an intervention action taken by one or several TSOs that changes the generation dispatch without modification of the system balance. This means that the amount of power infeed that is reduced e.g. in generation units operating according to the results of the scheduled dispatch simulation must be identical to the amount of additional power infeed of generation units operating in partial load or quick-start capable units. The objective of re-dispatching is to change dispatch at minimum additional costs while reducing all excessive power flows to admissible levels.[5] The re-dispatch costs are defined as costs incurred by the TSOs stemming from the accumulated payments coming from or going to power plant operators. The basic concept is that the financial situation for power plant operators affected by re-dispatch measures is equated to the situation without re-dispatch.

[5] Furthermore, network elements that have not been overloaded by scheduled dispatch must remain within their flow limits.

Thus, the TSO only compensates additional costs due to activated power infeed and absorbs avoided costs due to reduced power infeed, respectively (so-called “cost-based redispatch”)[6].

Roughly speaking, the delimitation between scheduled dispatch and re-dispatch simulation is marked by the gate closure of the day-ahead market. As we will describe below (subsection 3.1.2), this is sufficient for carving out the relevant effects of different bidding zone configurations. Taking into account the underlying assumptions of the simulation models, these two stages implicitly comprise the entire chain from long term markets to re-dispatch (fig. 3.1, upper and middle rows):

- Long term markets are used to hedge against uncertainties of short term markets. Since the scheduled dispatch simulation assumes perfect foresight, it is irrelevant whether this perfect knowledge on the system conditions is assumed to be available only on the day ahead or already at some earlier stage.
- The intraday market has two functions. Firstly, it is used by market participants to cope with incidents occurring after day-ahead gate closure, such as power plant failures or forecast deviations of infeed from renewables. Since the scheduled dispatch simulation assumes perfect foresight, this aspect of intraday activity is implicitly contained in the scheduled dispatch result. Secondly, the intraday market can be used by transmission system operators (TSOs) for counter-trading. This is a curative congestion management measure and thus contained in the re-dispatch simulation.[7]

6 This approach is sensible when only considering welfare aspects. Distributional effects, i.e. how redispatch costs affect consumers’ and producers’ surplus, depend on the specific regimes applied for passing on these costs. Assuming that these costs are passed on to consumers by means of grid tariffs (as applied e.g. in Germany), redispatch will not influence the producers’ surplus but reduce consumers’ surplus.

7 In this respect the simulated re-dispatch costs are overestimated, because they contain a share that in reality would be covered by the intraday market.

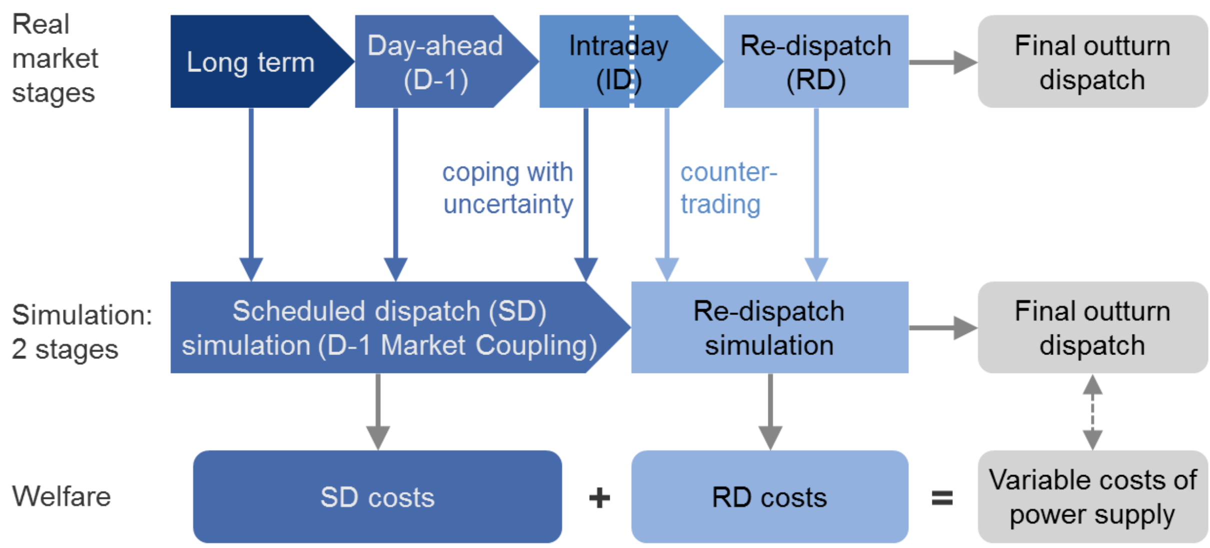

Fig. 3.1: Relation between real market stages, simulation approach and welfare measure

The variable costs of power supply, being the applicable welfare measure, are obtained by summing up the scheduled dispatch costs (derived from the scheduled dispatch simulation) and the re-dispatch costs (derived from the re-dispatch simulation), cf. fig. 3.1, bottom row.

Consequently, when comparing two scenarios (e.g. with different bidding zone configurations), the difference in static efficiency is equal to the difference in the variable costs of power supply, i.e. of the costs of the final outturn dispatch.

In particular, the minimization of only one cost contribution, e.g. minimization of re-dispatch costs, is not equivalent to maximizing static efficiency.[8]

3.1.2 General pros and cons of scheduled dispatch and re-dispatch

The key properties in which scheduled dispatch and re-dispatch differ are the following:

- Available power plants – During scheduled dispatch, reflecting the market stages up to day-ahead, all conventional generation units are freely dispatchable. In particular, there is

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8 This can be illustrated by means of a schematic example. We assume a comparison between scenario A and scenario B. In scenario B the costs of scheduled dispatch are € 150 Mio lower than in scenario A. By contrast, re-dispatch costs in scenario B are € 100 Mio higher than in scenario A. Although re-dispatch costs are higher in scenario B, scenario B yields higher static efficiency (by € 50 Mio), because the increase in re-dispatch costs is overcompensated by the decrease in scheduled dispatch costs.

enough lead time to freely decide which units will be running and which will be switched off.

By contrast, in the re-dispatching time frame the on/off decisions for “slow” thermal power plants cannot be reverted. This means that re-dispatching is restricted to altering the generation level of scheduled units (within their operational limits), with the exception of quickly startable units (such as gas turbines).[9]

- Precision of load flow control – During scheduled dispatch, transmission restrictions are respected in terms of upper limits for power exchanges between the bidding zones, while the geographic distribution of power generation inside each bidding zone is unrestricted. Therefore, while the transmission capacities between the bidding zones can broadly influence the load flow pattern, their precision is limited due to the uncertainty of generation (and load) distribution inside the zones.[10]

  In contrast to this zonal resolution, re-dispatching is performed on a nodal basis and thus yields a higher precision in terms of controlling the power flows.

- Market based vs. regulated – Scheduled dispatch is determined through market based processes. By contrast, re-dispatching should preferably be organised as a regulated, cost based process. This is recommendable in order to avoid issues of local market power, and it is acceptable as long as the market based processes are the major drivers of the final outturn dispatch. While this distinction cannot be considered in the numerical simulations, we will return to it when discussing market power in chapter 4.

[9] Further flexibility of idle generation units that are not quick-start capable are not considered in the re-dispatch simulations. Getting access to this flexibility would require a preventive activation of such power plants. The resulting replacement of generation units with less generation costs would be contradictory to the aim of a market-based generation dispatch at minimum costs.

[10] Note that this general property of the zonal market structure is irrespective of whether the transmission capacities are expressed as ATCs (as is currently the case and also implemented in the simulation model) or by flow-based parameters.

3.1.3 Impact of bidding zone structure not trivial when uncertainties are taken into consideration

In an ideal simulation scenario, small bidding zones appear to have advantages over large ones:

- In large zones the result of the scheduled dispatch may turn out inefficient when considering its grid impact, i.e. it may need to be corrected by re-dispatch to avoid excessive grid utilization. But re-dispatch cannot correct on/off decisions of slow thermal power plants. Consequently, some inefficient on/off decisions may persist in the final outturn dispatch.
- Smaller zones improve the precision of load flow control during the scheduled dispatch stage, such that the efficiency of on/off decisions is increased, and the need for re-dispatch is reduced.

Therefore, in an ideal simulation scenario smaller zones appear to clearly increase efficiency. However, the clearness of this finding relies on the fulfilment of the assumption that all conditions can be perfectly foreseen, such that scheduled dispatch is performed in an optimal way, regardless of the size and shape of the bidding zones. In reality, however, scheduled dispatch is subject to several uncertainties:

- The time frames up to day-ahead, when the on/off decisions must be taken, are subject to significant uncertainties. One of these is the day-ahead forecast error of RES infeed. Another example is the fact that it is impossible to determine a perfect level of transmission capacities for each hour, given the numerous uncertainties the TSOs have to cope with when doing their calculations. Consequently, the preconditions for perfectly efficient scheduled dispatch – i.e. enough lead time for free on/off decisions and perfect knowledge on all system parameters – are mutually exclusive.
- Due to the impossibility of determining perfect hourly transmission capacities there is generally a risk that parts of the transmission network are temporarily under-utilized.[11] But under-utilization cannot be resolved by re-dispatch (because only over-utilization of the grid

[11] This could only be avoided by systematically allocating over-estimated, high transmission capacities. However, this would result in excessive re-dispatch, thereby annihilating the effect for which bidding zones and transmission restrictions between them were introduced in the first place.

constitutes a trigger for activating re-dispatch measures). This aspect becomes more relevant the smaller the bidding zones are, because smaller zones means more zones, which leads to more commercial borders for which transmission capacities need to be determined.

As a consequence of the aforementioned uncertainties, the efficiency of scheduled dispatch is, by principle, limited. Therefore, the efficiency gain of introducing smaller bidding zones, which in theory is based on the optimization of scheduled dispatch, becomes less clear when taking into account uncertainties.

In the next step we perform an exemplary quantification of this effect. The example looks into the impact of different levels of transmission capacity as a source of uncertainty.[12]

3.1.4 Exemplary numerical assessment

Set-up

The exemplary numerical assessment considers the power system of Germany and its neighbouring countries plus Italy. The model is calibrated to the status quo of the year 2013. This is appropriate for the purpose of this study, which is to provide a generic methodical assessment rather than a particular zone recommendation for a particular future time period. The latter would require modelling future developments, which would naturally require assumptions. Such arbitrariness is avoided by sticking to the status quo of the recent past.

When considering an introduction of smaller bidding zones, one uncertainty is the level of transmission capacity on the newly introduced commercial border. In order to analyse the relevance that this has on the static efficiency assessment, we compare three scenarios (fig. 3.2). One represents the status quo in terms of bidding zones and transmission capacities. We then consider an alternative bidding zone configuration where Germany is split into a Northern/Eastern and a Southern/Western zone (the latter being joined with Austria). For this alternative bidding zone configuration we distinguish two scenarios, the difference between them being the amount of transmission capacity at the newly introduced commercial border in Germany. We then compare the variable costs of power supply between all three scenarios.

[12] Note that other sources of uncertainty are neglected in the example, such that the simulation overestimates the efficiency of smaller bidding zones.

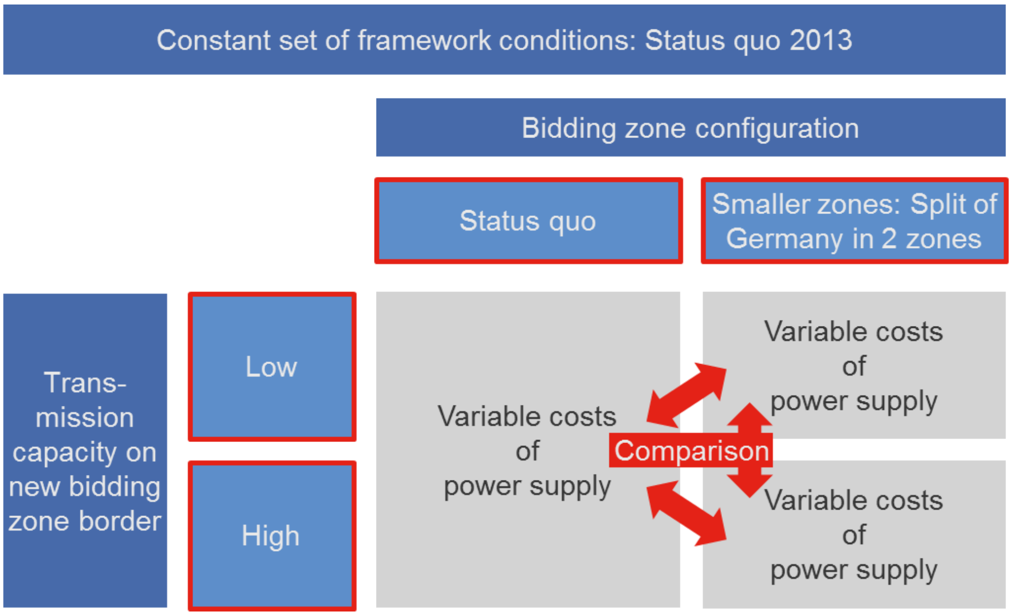

Fig. 3.2: Exemplary quantitative analysis of static efficiency: Comparison between three scenarios

When determining a reasonable course of the new bidding zone border through Germany we firstly follow the general goal to obtain two zones of similar size, which mitigates adverse effects, be it on market power and liquidity or on the ability to safely operate the system. Secondly, we analyse the geographical occurrence of physical congestion (i.e. overloaded network elements) resulting from the scheduled dispatch simulation of the status quo. The new bidding zone border is then chosen such that it is close to the relevant congested North-to-South lines in the middle of the country.

The transmission capacities on the new commercial border are derived from the exchange pattern in the status quo, by following two different strategies. The “high NTC” level represents an approach where the impact of the zone split is confined to relatively extreme situations. This is achieved by choosing the high NTC such that the commercial exchange between the two new bidding zones is restricted in ca. 1,000 hours of the year (ca. 11 % of the time). The “low NTC” level is chosen such that the commercial exchange is restricted during roughly half of the time, which represents a more progressive approach towards avoiding physical congestion and reducing re-dispatch effort.

Results

As regards the scheduled dispatch costs, the simulation results (fig. 3.3) reflect the aforementioned approaches for determining the two different NTC levels: While the “low NTC” scenario leads to a significant restriction of scheduled dispatch, the “high NTC” scenario yields only a very moderate increase of scheduled dispatch costs.

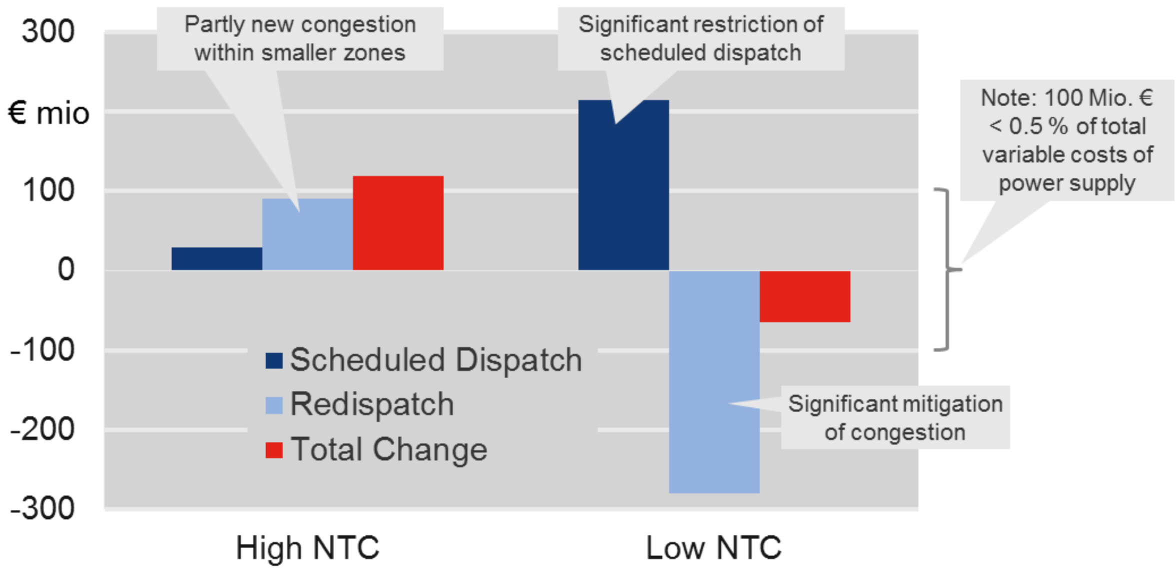

Fig. 3.3: Exemplary numerical assessment of static efficiency (simulated year: 2013): Simulated annual cost differences between “smaller zones” scenarios (for two levels of NTC) and status quo

In the “low NTC” scenario, the re-dispatch costs are significantly reduced compared to the status quo. This shows that the restriction of scheduled dispatch mitigates congestion. In total, increase of (scheduled dispatch) costs and decrease of (re-dispatch) costs practically level out each other in this exemplary analysis.

By contrast and maybe somewhat unexpectedly, re-dispatch costs increase when splitting the bidding zone and introducing the “high NTC” level on the new border. A detailed analysis reveals that this is caused by new cases of congestion that arise inside the “smaller”, albeit still quite large bidding zones. Hence the rough geographical control of power flows by limiting power exchange between the two new zones is, in terms of benefit for grid utilization, overcompensated by changes of scheduled dispatch inside the zones as a reaction to the new bidding zone structure.

The results show that the level of transmission capacity at the newly introduced bidding zone border has an important influence on how splitting the zones impacts the contributions to static efficiency. In a more general sense this means that a re-configuration of bidding zones cannot be judged without regarding the relevant sources of uncertainty (of which the transmission capacity level is only one). Depending on the specific situation, introducing smaller bidding zones may even exacerbate physical congestion.

The impact of the bidding zone re-configuration on the total variable costs of power supply (red columns in fig. 3.3) is relatively small, regardless of the level of transmission capacity on the new border. In the "high NTC" scenario both cost contributions change to only a minor extent, while in the "low NTC" scenario the individual contributions are larger, but mostly level out each. In both cases the total effect is well below 1 % of total variable generation cost in the modelled system and hence in the order of magnitude of the model accuracy.

All in all, the results of the numerical assessment indicate that the impact of downsizing bidding zones on static efficiency is relatively modest, with unclear sign

3.2 Dynamic efficiency

In the previous chapter we have analysed the impact of re-configuring the bidding zones under the assumption of constant framework conditions. In the following, we turn to aspects of dynamic efficacy, which means that transitional effects as well as repercussions between the configuration of bidding zones and the framework conditions are taken into consideration.

3.2.1 Network expansion

Interplay between network expansion and re-configuration of bidding zones

Any attempt to determine an "optimal" configuration of bidding zones is based on the location of congested elements or regions of the network. This is because the bidding zone borders shall primarily be laid out such that they impose restrictions on cross-zonal power transfers in order to reduce the power flows in those congested locations.

An alternative measure for mitigating congestion is to expand the network. It is evident that when a network expansion measure relieves congestion at a particular location, this location no longer requires relief by a limitation of cross-zonal power transfer. Therefore, the “optimal” configuration of bidding zones depends on the network configuration.

But the network configuration is undergoing continuous development, since numerous expansion projects are planned for the next years. Formalized procedures have been installed at EU and member states’ levels in order to coordinate and facilitate network expansion. ENTSO-E publishes the Ten-Year Network Development Plan (TYNDP) on a biannual basis. In Germany, for instance, the national network development plan is updated annually, and the approval of expansion projects constitutes a legislative act.

However, despite this strong political and institutional support for network expansion, the authorization procedures are often delayed. Local or regional opposition against expansion projects constitutes a significant source of uncertainty as regards the concrete schedule of implementation.

Thus, on the one hand it is clear that the network configuration will change in a dynamic way, but on the other hand the concrete schedule of network development is uncertain. This means that an important prerequisite for determining an “optimal” bidding zone configuration is inherently uncertain. Also, it is not possible to overcome this uncertainty by making the bidding zone structure dynamically following the network situation. This is because the shorter a new configuration of bidding zones remains in place, the less beneficial incentives it can yield and the more transition costs[13] are incurred. Therefore, the Guideline on CACM prescribes that a first review of a modified bidding zone structure shall be made three years after its implementation.

Consequently, even if a new bidding zone configuration could be properly shaped with respect to a particular expected future state of the network, it is very likely that the actual configuration of the network will be significantly different from this expectation once the new bidding zone configuration has been implemented.

Moreover, it is not only the development of the network, i.e. the “hardware”, which is uncertain. Additionally, the development of commercial transmission capacities, following the implementation of network expansion projects, constitutes an uncertain factor. On the one hand, TSOs may argue that, insofar as the expansion project aims at relieving congestion, its purpose would

[13] Sometimes these are summarised under transaction costs. By using the term transition costs we want to clarify that one-off costs of migrating to a new bidding zone structure are meant.

be rendered void if increased transmission capacities led to further increasing power flows. On the other hand, market participants may call for an increase of capacity in order to benefit from the reinforced network infrastructure.

Exemplary numerical assessment

An exemplary numerical simulation shall serve to demonstrate the effect of uncertainties related to the interplay between re-configuration of bidding zones, network expansion and transmission capacity adjustment. The basic set-up (modelled system of Germany, its neighbouring countries and Italy; simulation year 2013) is identical to the exemplary static efficiency analysis (section 3.1.4). Again we analyse a split of Germany into a Northern and a Southern zone, where the boundary between these zones is laid out according to the congested locations in the status quo (prior to re-dispatch). Although this is not a formally "optimal" bidding zone configuration, it is clearly adapted to the status quo situation, including the respective network configuration. We use the "low NTC" level of the static efficiency assessment as the starting point (fig. 3.4).

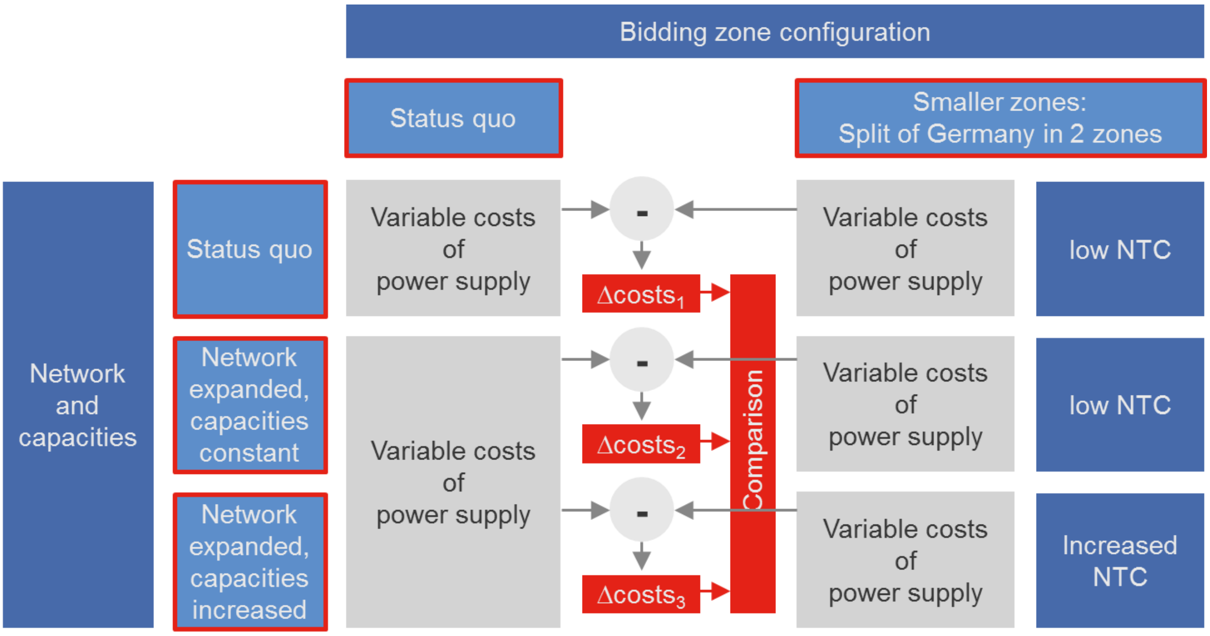

Fig. 3.4: *Exemplary quantitative analysis of dynamic efficiency: Welfare impact of modification of biding zones, compared between three scenarios of network/capacities*

The effect of uncertainties is then introduced in two steps:

- First, a group of network expansion projects is added to the model. The projects are located such that they relieve the network in the vicinity of the border between the assumed Northern and Southern German bidding zones. This scenario represents a situation where the actual network configuration differs from the one for which the re-configuration of the bidding zones was determined. The transmission capacity on the newly introduced bidding zone border remains unchanged in this scenario, i.e. the network expansion only serves to relieve the network and reduce the demand for re-dispatching.
- Second, in addition to the expansion of the network, the level of transmission capacity on the newly introduced bidding zone border is increased, such that scheduled dispatch is less restricted (reflecting that market participants would benefit from the network expansion).

Fig. 3.5 shows, for each of the three scenarios, the impact of re-configuring the bidding zones on the costs of scheduled dispatch, of re-dispatch and the impact on total variable costs of power supply.

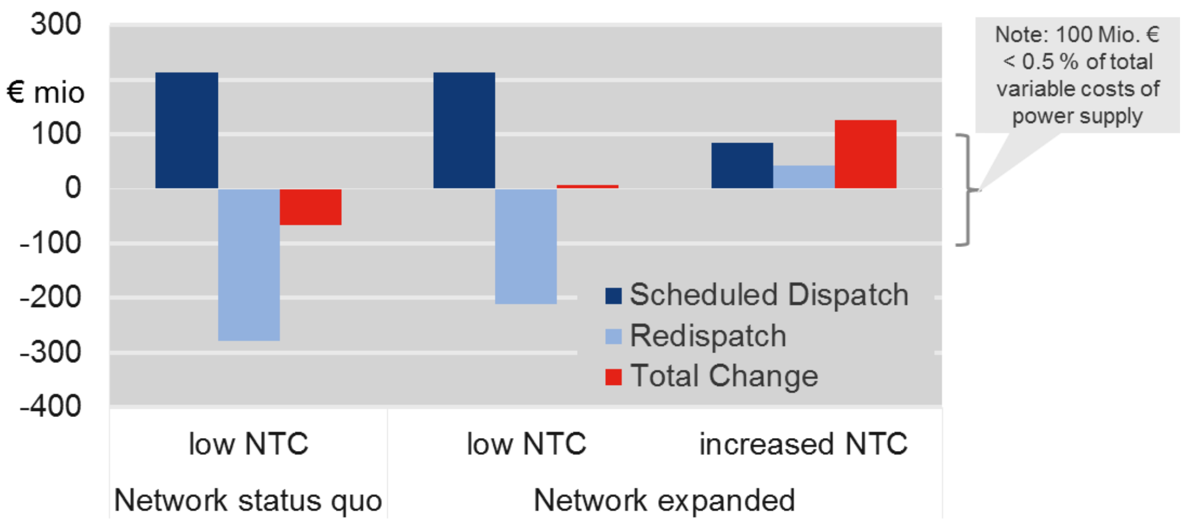

Fig. 3.5: Exemplary numerical assessment of dynamic efficiency (simulated year: 2013): Simulated annual cost differences between "smaller zones" scenario and status quo for three different scenarios of network/capacities

The results for the starting point (left group of columns in fig. 3.5) are those from the static efficiency assessment, where changes of scheduled dispatch costs and re-dispatch costs almost level out each other.

When the small bidding zones are introduced although the network has been expanded (middle group of columns in fig. 3.5), the split of bidding zones yields less reduction of re-dispatch costs. Consequently, the re-configuration of bidding zones is less efficient in this scenario. This reflects that the network expansion relieves the network and, hence, resolves parts of the reasons why the new bidding zone border has been introduced.

When the network is expanded and the bidding zone split is introduced with an increased NTC level (right group of columns in fig. 3.5), the re-configuration of the bidding zones imposes less restrictions on the scheduled dispatch, such that scheduled dispatch costs increase less than in the other two scenarios. At the same time, the zone split has less impact on the re-dispatch costs: Due to the combination of already relieved congestions in the status quo bidding zone structure (as a consequence of network expansion) and the increased NTC, the (small) reduction of re-dispatch demand through limitation of North-to-South power transfers in Germany is entirely compensated by a few newly occurring congested spots inside the smaller (yet still quite large) bidding zones.

To summarize, the exemplary numerical assessment shows that the uncertain course of network development makes the re-configuration of bidding zones less efficient compared to an idealistic assessment with perfectly known framework conditions. Moreover, the level of commercial transmission capacity at the newly introduced border(s) constitutes an additional distorting factor widening the bandwidth of potential outcomes of the bidding zone re-configuration.

3.2.2 Investment incentives

Expected benefits of bidding zone re-configuration from a theoretical perspective

The introduction of smaller bidding zones can be seen as an instrument to make congestion more transparent. The information about congestion is transformed into a market signal, because generation plants on both sides of a new bidding zone border no longer “see” one uniform market price, but two different price levels. This should, theoretically, provide economic incentives for the efficient location of new generation facilities. At the same time, it would reveal where network expansion would be most efficient.

However, such expectations are largely based on theoretical considerations and neglect dynamic effects and interdependencies. In the following, we discuss how such dynamic effects and practical considerations may affect the assessment of investment incentives provided by new bidding zone structures. Moreover, it is important to bear in mind that re-configuring bidding zones is only one out of several alternative ways to deal with congestion.

Feedback of investment on efficiency of bidding zone configuration

Under the assumption that changing the bidding zone structure generates effective investment incentives, the implementation of the investments will change the framework conditions under which the bidding zone structure has been determined. Due to this feedback loop (fig. 3.6) the new bidding zone configuration would, by intention(!), eliminate the reasons for its creation.

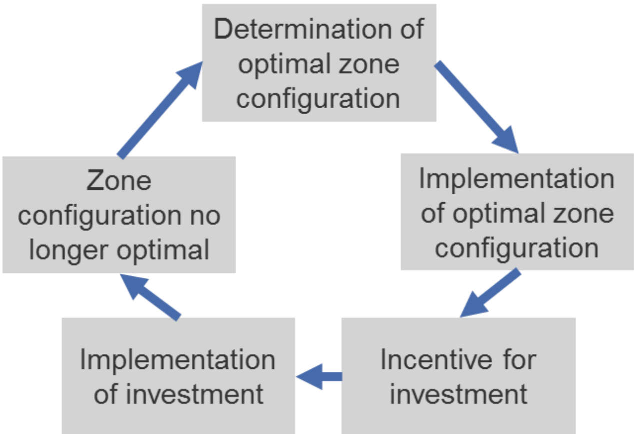

Fig. 3.6: Feedback loop of investment on bidding zone configuration

The exemplary numerical assessment of the interplay between network expansion and bidding zone configuration in the previous subsection confirms the relevance of this feedback effect: Since both the splitting of the bidding zone and the expansion of the network aim at removing congestion (in the same region), it is evident that as soon as the incentivized investment is implemented, the new bidding zone border is less needed. The same feedback effect applies to generation investment: If the location of new power plants was mainly selected because of power market price differences between newly shaped bidding zones, then the commissioning of new plants would reduce these price differences, such that the bidding zone structure may no longer be suitable.

Since the frequency of bidding zone re-configurations is and should be limited (cf. subsection 3.2.1), the effect of this feedback loop cannot be avoided, by principle.

One could argue that, generally, the mitigation of price differences is an economically desired effect of the investment incentives. However, in this particular case, there are repercussions between three processes – bidding zone (re-)configuration, network investment and generation investment –, that are at best loosely coordinated, all of which are subject to significant latencies, and two of which are highly regulated. This makes it unrealistic to expect that a re-configuration of bidding zones will contribute to an overall increase of efficiency – the more so as it yields significant transition costs (cf. section 3.2.3).

Questionable effectiveness of investment signals for generation location

When deciding on the location of new power plants, investors take numerous factors into account. This includes, inter alia, the availability of primary energy (or the price thereof, including transport costs), access to cooling water, local administrative support, the possibility to re-use existing plant locations, and the existence of local heat sinks (for combined heat and power plants).[14] Given the number and relevance of such factors it appears obvious that price differences between bidding zones are only one aspect among several when it comes to deciding on power plant locations.

This is even more so as the power price difference between bidding zones is far from being stable and forecastable, for the following reasons. Firstly, there is a repercussion of investments (in particular, non market-based network investments) on the power prices and thus the inter-zonal price differences. Secondly, the more credible it is that bidding zones will be re-structured with the aim to provide investment signals, the more probably any new configuration will be changed again (as a consequence of the above mentioned feedback loop), thereby modifying or removing previous price signals. And thirdly, and partly as a consequence of the previous two aspects, spot market prices and inter-zonal differences between them tend to be volatile, in particular in the light of the long-term nature of investments in power plants.

The weakness of investment signals from locational spot market price differences is confirmed by practical experience in markets where such locational prices exist. In order to demonstrate

[14] Similar considerations apply to investments in large industrial plants.

this, we provide in the following two case studies: The PJM market in the U.S. and the Italian market.[15]

Case study: PJM

PJM is a regional transmission organization (RTO) that coordinates power transmission and wholesale market in all or parts of 13 U.S. states and the District of Columbia (61 million inhabitants). The market consists of several segments, e.g. day-ahead, real-time (balancing), financial transmission rights, ancillary services and capacity market.

The PJM market model is generally based on nodal pricing. This can be interpreted as an extreme form of small bidding zones, where each node of the transmission system has individual prices.

Investigations in the middle of the last decade came to the conclusion that there was a general lack of investments in generation units, and that the locations of new investments were not related to the nodal prices. Fig. 3.7 shows that the majority of new generation was installed in medium low and low price areas. This is contradictory to the theoretical expectation that higher spot prices would attract new generation. Apparently, other factors besides the relative price levels have been more important for the selection of new power plant locations.

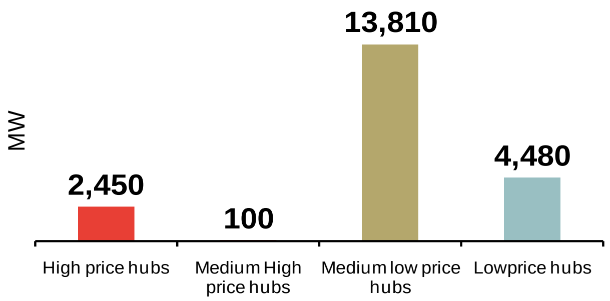

Fig. 3.7: Investments in new generation in PJM from 2000 to 2006 (Source: Frontier Economics/Consentec based on Synapse Energy Economics [2])

[15] The case studies are updates from our joints study with Frontier Economics for the German federal regulatory authority, Bundesnetzagentur, from 2011 [2].

As a consequence of the lack of generation investments, an additional capacity market called “Reliability Pricing Model” (RPM) was introduced in 2007. It is based on yearly capacity products with a validity period of up to three years in advance.

In 2011, a performance assessment of the RPM was prepared [3]. Among other aspects, this report discusses the finding that RPM prices in the main import constrained region are too low to attract sufficient new investment. Moreover, the general uncertainty and volatility of RPM prices is deemed too high to viably support investment decisions. Hence, neither short term nor 3-year-ahead locational or regional prices provide (sufficiently strong) investment signals in PJM.

Furthermore, the RPM performance assessment report discusses the interdependence between network expansion and generation investment, which hinder each other: The uncertainty of future transmission capacity levels leads to volatile prices of generation capacity. This uncertainty is an obstacle to generation investment. Since, in PJM, network expansion follows actual generation development, uncertain generation investment results in uncertain development of transmission capacity, thus closing the circle. Hence, the interdependence between network and generation investment weakens the credibility of price signals.

It is important to note that in the EU, network expansion planning is generally based on exogenous scenarios of renewable and conventional generation. Compared to the above mentioned PJM experience, this tends to stabilize the investment climate for network expansion projects, while making it even less attractive for investors to base their locational decision for generation units on a particular regional scarcity of transmission capacity. The risk that price signals from bidding zones will decline or vanish due to network expansion is, in this respect, higher in the EU than in the PJM system, although even there the price signals do not appear viable enough.

Case study: Italy

The Italian power market is divided into six bidding zones. This structure has been in place since the market was liberalized.

In order to analyse the relation between zonal price differences and investment decisions, we focus on investment in gas fired power plants. This is appropriate because the gas network allows for a relatively free choice of location of gas fired power plants. Moreover, gas fired plants account for the majority investment projects.

Fig. 3.8 shows new capacity that has been built since 2007 or is under construction or planned for the time period until 2020. When comparing these capacity figures to the average day-ahead prices of the bidding zones during the period from 2004 to 2013[16], and ignoring the special cases of the island zones (Sardinia and Sicily), one can see that the strongest investments have been made in those zones that yield the lowest prices, namely the North and the South zones. Hence, price differences between the bidding zones do not appear to be the predominant factor for choosing the location of new power plants, and other factors besides short term prices are at least equally important to investors.

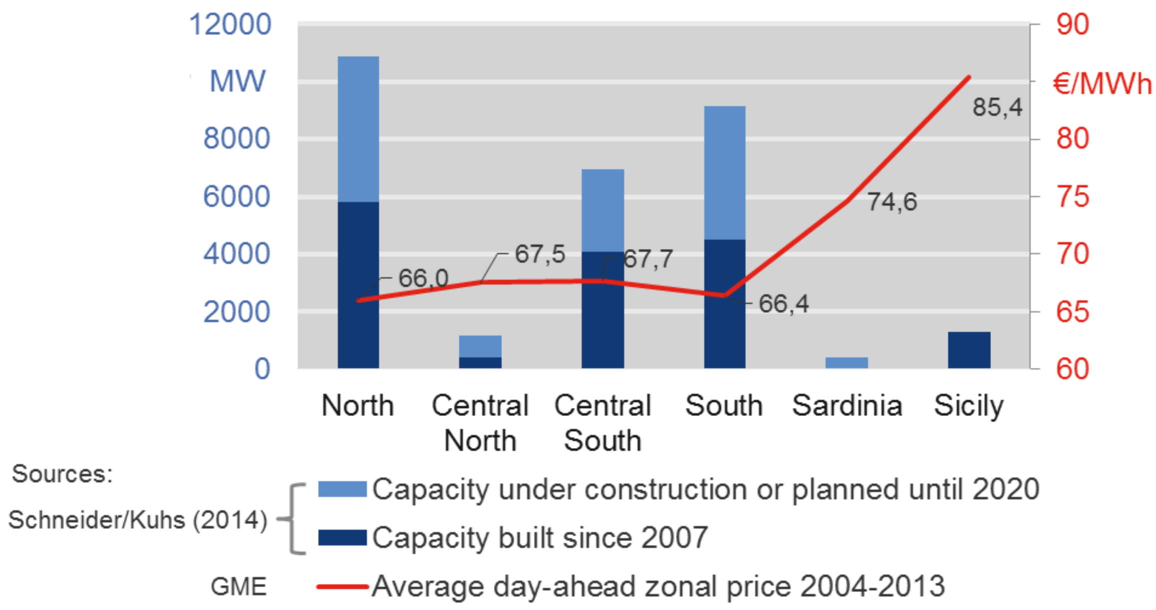

Fig. 3.8: Comparison of zonal prices and investment in gas fired power plants in Italy

Network investment may become more difficult with smaller bidding zones

The main barrier for network investment is the long lead time in combination with public resistance against new transmission lines. The introduction of smaller bidding zones may exacerbate this situation. This is because local opponents against network expansion might argue that by adapting the bidding zones to the congested spots in the network, market forces (i.e.

[16] Although historical prices are used here, the lag between the period of price evaluation and the (prospective) commissioning period approximates the fact that investment decisions are based on prospective prices.

restricted scheduled dispatch) deal with congestion in a sufficient manner. As a consequence, the administration of scarce network resources would be preferred to the removal of such scarcity by efficient development of the network.[17]

Alternative ways to provide investment signals exist

When considering how to provide proper investment signals, one should keep in mind that implementing a new configuration of bidding zones would be only one out of several means to achieve the goal. Further options include (without claiming to be exhaustive) capacity mechanisms, locational grid tariffs, auction procedures for new generation, and direct investment support for transmission infrastructure.

Hence, when assessing investment signals, a mere comparison between different bidding zone structures is too narrow. A re-configuration of bidding zones is not indispensable for achieving investment signals.

3.2.3 Transition costs

Several technical and commercial processes depend on the configuration of bidding zones, for example:

- Market processes including trading, supply, scheduling and settlement – All these processes are organized along the structure of bidding zones. All generators and consumers in a bidding zone are exposed to the same prices, while traders and suppliers need to take further actions to deal with price differences between different bidding zones. Since all members of a balancing group must be located in the same bidding zone, re-configuring the bidding zones modifies the composition of the customer portfolios, changes intermixing effects of load profiles, etc.
- Preventive congestion management – Congestion management comprises several interdependent processes, ranging from the creation of forecast network models to the calculation of transmission capacities and finally to capacity allocation processes such as market coupling. All these processes are adapted to the configuration of bidding zones.

[17] This argumentation could be seen as particularly attractive in the region that would expect lower power prices as a consequence of introducing smaller bidding zones.

- Network operation – Load/frequency control of the European transmission system is organized such that the physical export and import is controlled on the level of control areas. The concept of bidding zones is based on the idea that the amount of power transfer between them is limited (while it is not limited inside the zones). In order to technically implement this concept, bidding zone borders must coincide with the borders of control areas.[18]

As a consequence of these dependencies, altering the bidding zone structure yields substantial transition costs. At first, this relates to the re-configuration process as such:

- The determination of a new bidding zone structure involves substantial efforts for analyses and negotiations.
- Adjustments of the legal framework may be required in countries affected by the re-configuration, as several aspects of energy legislation, support for renewables, etc., may be based on the assumption of uniform power prices and unrestricted power transfers on domestic level.
- Congestion management and market processes need to be adapted in order to reflect the new bidding zone structure and ensure that it the re-configuration has the intended commercial and physical effects.

Next, the new bidding zone structure needs to be implemented by TSOs, power exchanges and market participants:

- Numerous IT systems need to be adjusted.
- Power contracts must be re-negotiated if their reference location of price changes or is no longer accepted by the contract parties (in particular, when the reference location is located in a former bidding zone that has been split).
- Balancing groups and, consequently, customer portfolios need to be adjusted to the new structure.

It is important to note that splitting bidding zones or re-configuring them irrespectively of existing borders yields higher transition costs than merging entire bidding zones. For example, the problems of ambiguous reference locations of contracts and the need for legal adjustment or modification of control areas are not or less relevant when merging entire zones.

[18] There may be several control areas inside a bidding zone, but not vice versa.

It is difficult to estimate the magnitude of transition costs as they consist of numerous aspects and elements. In any case, any efficiency gains achieved by a bidding zone re-configuration will need to be set off against the transition costs that are incurred to implement the new configuration.

Given that, according to the numerical analysis and further considerations as described in the previous sections,

- the static efficiency effect of smaller bidding zones tend to be modest if the mutual compensation of changes in scheduled costs and re-dispatch costs are taken into account;
- dynamic effects and uncertainties tend to decrease efficiency gains compared to static conditions,

it appears likely that the transition costs are in a similar order of magnitude as the static and dynamic efficiency effects, such that they must not be neglected when assessing the total welfare effect of introducing smaller bidding zones.

3.3 Distributional effects

As mentioned in section 2.1, the objective of congestion management is to increase pan-European social welfare. Purely distributional effects should, according to the Regulation on CACM[19], not constitute a criterion for assessing congestion management in general and bidding zone configurations in particular. Nevertheless, distributional affects are relevant in practice, where any development is, *inter alia*, judged from country or stakeholder centric perspectives. For example, loop flows are often criticised for serving the internal optimisation of one large bidding zone at the expense of limiting power transfer opportunities for neighbouring countries hosting the loop flows. By splitting the large bidding zone, even if the final outturn dispatch would remain unaffected, the former internal optimisation inside the large zone would become a cross-zonal exchange of power. This would have an impact on wholesale prices and, consequently, on the distribution of consumers' surplus, producers' surplus and congestion rent in each bidding zone.

[19] Cf. [1], Article 32

In order to demonstrate the quantitative relevance, we decompose the results of the static efficiency analysis (cf. section 3.1.4) by country; for Germany, where the exemplary split is modelled, Northern and Southern bidding zones are shown individually. Fig. 3.9 shows that the welfare effect for individual countries or bidding zones can be larger than the total change welfare due to the re-configuration of the bidding zones. This does not only apply to the bidding zone which is simulated to be split, but also to some of the neighbouring zones.

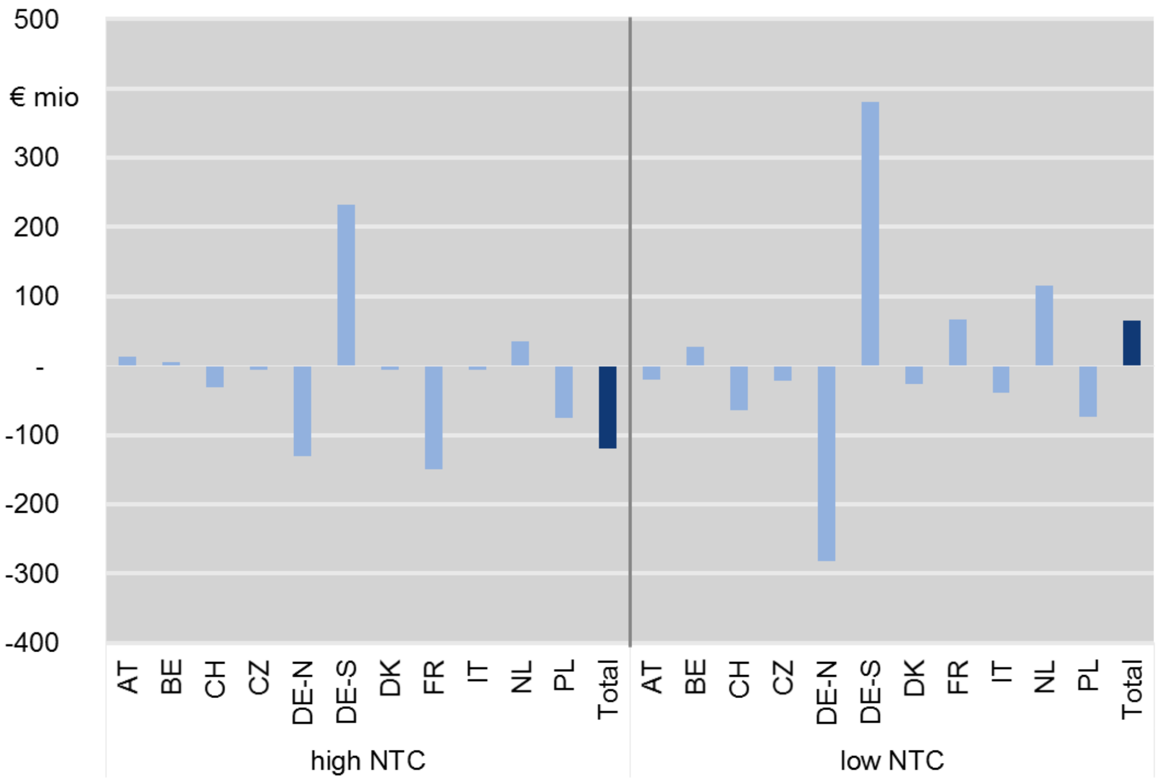

Fig. 3.9: Exemplary numerical assessment (simulated year: 2013): Change of annual welfare gain (compared to status quo) by introducing NTC between DE-N and DE-S

The effect is even amplified if welfare changes are further decomposed into their components, i.e. producers' rent, consumers' rent and congestion rent (the latter including rents accruing from market coupling plus – negative – rents from re-dispatching). As a consequence of changes in the market prices, consumers' and producers' rent yield significant changes in opposite directions.

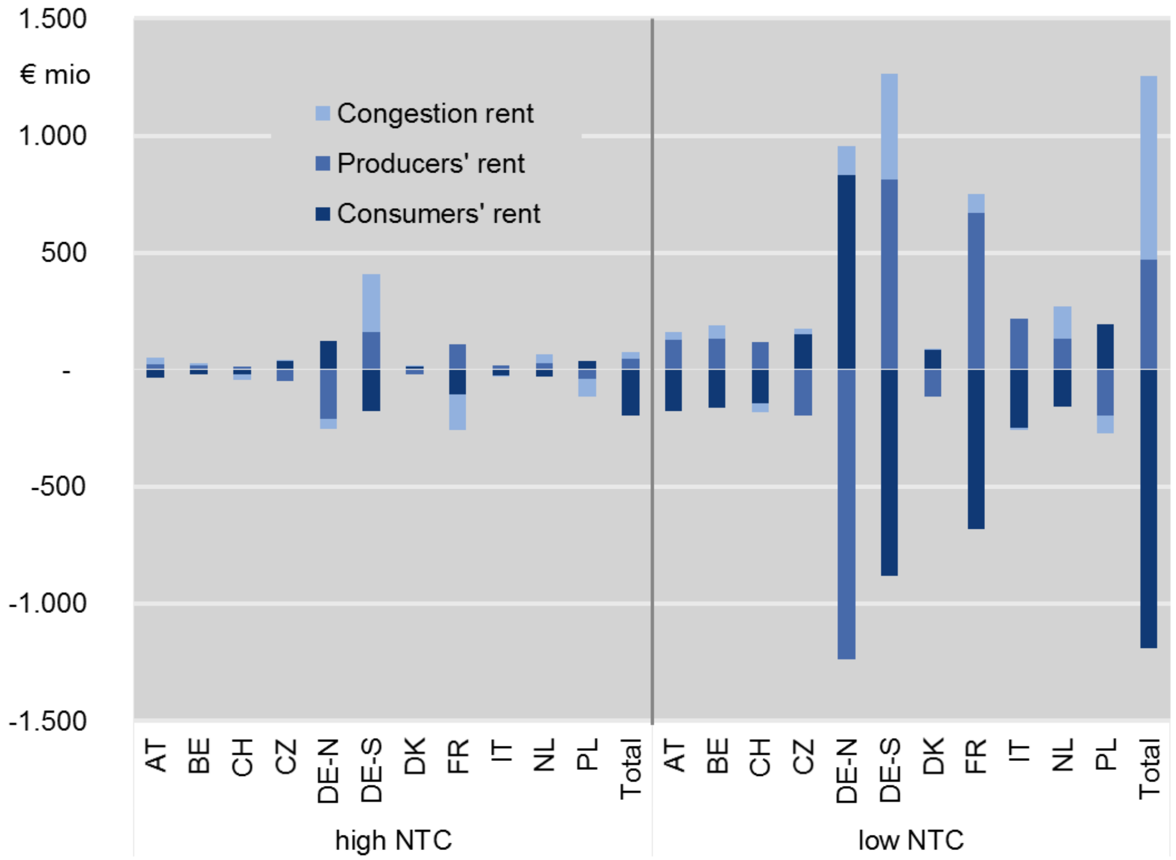

Fig. 3.10: Exemplary numerical assessment (simulated year: 2013): Change of welfare components (compared to status quo) by introducing NTC between DE-N and DE-S

It is important to bear in mind that the particular results shown in the above exemplary diagrams strongly depend on the assumed framework conditions, model assumptions etc. Nevertheless, they underpin the general finding that distributional effects are of significant size, although they should not be primary criteria for assessing bidding zone configurations. While re-configuring bidding zones – in particular, introducing smaller zones – may be effective to address distributional effects, it appears likely that this would come at the expense of reduced overall welfare. Moreover, the distributional effect of a – centralized – process of bidding zone re-configuration is difficult to plan because distributional effects are also strongly affected by – decentralized – national political and regulatory decisions. Therefore, explicit compensation schemes should be preferred to bidding zone restructuring in order to resolve issues with distributional effects.

4 Liquidity and market power

General considerations

A comprehensive discussion about the impact of introducing smaller bidding zones on market liquidity and market power can be found in [4]. This chapter provides a brief summary of those considerations, followed by a case study on liquidity with respect to the hedging of inter-zonal price differences in the Nordic market.

- Liquidity concerns the ability of market players to constantly have available trading partners with which they can enter into contractual positions and also reverse out of them through further trades with the same and other parties and to do so without their individual trades significantly upsetting the level of market prices. Liquidity is essential to the European model of electricity trading, which is based on a decentralised organisation. Any negative impact on market liquidity would yield welfare losses.
- Even if liquid trading only applies to delivery periods of one or a few years in advance, this liquidity is also helpful for investors in long-term assets such as power plants.
- Any policy measure resulting in a decrease of market liquidity – such as a downsizing of bidding zones – will be reinforced by behavioural adjustments of market participants (the extent of which is complex to forecast).
- Large markets with highly diverse participants tend to be more liquid and therefore incur measurably lower transaction cost. In [4] this is shown along an exemplary comparison of bid-ask spreads[20] between the power markets of Germany, Belgium and The Netherlands, indicating that the differences in liquidity would account for transaction costs in the order of 100 million € in the German market.
- Liquidity measures cannot be added across bidding zones – Some proponents of smaller bidding zones argue that although measures such as trading volumes would be smaller in each of the new bidding zones, the existence of transmission capacity between these zones

[20] The bid-ask spread is the difference between the highest price that a buyer is willing to pay for a product and the lowest price for which a seller is willing to sell it. It represents the transaction cost for participating in a market and is a key measure of liquidity, where more liquid markets are characterised by lower bid-ask spreads [4].

would avoid a decline of liquidity as volumes may actually be added up in order to describe the liquidity from a regional perspective. However, the new bidding zones borders are, by principle, introduced in order to restrict the power transfer between the smaller zones. But then, such constraints on cross-zonal power transfer are the reason why the markets in the bidding zones are gradually separated, such that market participants do not see them as one joint area. The above mentioned assessment of bid-ask spreads in three bidding zones of the Central Western European region – where the modalities of cross-border capacity allocation are among the best-developed in Europa – shows that liquidity is in fact lower in the smaller zones, despite the well-functioning management of cross-zonal power transfers.

- Risk hedging becomes more difficult the smaller the bidding zones are – Proponents of smaller bidding zones may argue that risks associated to the difference between zonal prices can be hedged, such that ultimately, the size of the larger joint area (comprising several bidding zones) matters in terms of liquidity. Such arguments appear to be based on the idea that "mainly" a system-wide power product is (liquidly) traded, such that "only" the differences between some system-wide (e.g. average) price and the respective zonal prices need to be hedged. This resembles the situation in the Nordic market where indeed the so-called system price (which is determined under the assumption of infinite transmission capacities) is used as the reference price for the wholesale market. However, there remains a risk of price differences between the system price and the bidding zones' prices. In the Nordic market, so-called Contracts for Differences (CfD) are, in principle, available to manage this risk. However, it is obvious that the smaller the bidding zones become, the higher the number of bidding zones gets, the more of such products are needed, and the lower the number of market participants that involve in the trading of each particular product. Hence, hedging against the zonal price risk becomes more difficult with smaller bidding zones, thereby reducing liquidity.

- Large bidding zones are most efficient to deal with market power – Proponents of smaller bidding zones allege a problem of market power associated with re-dispatching due to its nodal nature. Under the assumption that smaller bidding zones reduce the demand for re-dispatch, they conclude that this is the means to reduce market power. But this logic is flawed, for two reasons:
    - Re-dispatch is required anyway – Even if bidding zones become smaller, there is still a need for re-dispatch in order to deal with intra-zonal congestion. This can already be

demonstrated by simulations of static system conditions, but it becomes even more relevant given the fact that bidding zone configurations cannot follow the dynamics of system development. Consequently, on the one hand, smaller bidding zones do not systematically resolve the risk of market power in nodal re-dispatch – but on the other hand, they do raise the risk of market power in the zonal market segments as there is more and more concentration of market participants with relatively large size in the individual bidding zones.

- Market power in re-dispatch affects the individual power plant, market power in the zonal market the entire bidding zone – Downsizing bidding zones increases the potential for market power in the zonal forward and sport markets. This could lead to increased prices in the entire zone and, thereby, to a significant burden on consumers.

  By contrast, remuneration for re-dispatching is node or plant specific. Hence, the exercise of market power in re-dispatch would benefit (some of) the few plants that are used for re-dispatch, but would not raise the market price in the entire bidding zone. In other words, a market power issue with respect to re-dispatch would be confined to a small part of the market. Moreover, the exercise of market power in re-dispatch can be avoided, since a regulation of the re-dispatch process is feasible and acceptable if it helps ensuring efficiency of the much larger forward and spot markets.

Case study: Hedging of inter-zonal price differences in the Nordic market

We noted above that in the Nordic market, so-called Contracts for Differences (CfD) are, in principle, available to manage the risk associated to price differences between the system price and the prices in the individual locations of delivery, i.e. the bidding zones. The Nordic market is insofar interesting to study as the single Swedish bidding zone was divided into four zones in 2011.

Even prior[21] to this split, however, liquidity of CfD trading was apparently low. Fig. 4.1 shows that CfD trading volumes only amount to a modest fraction of the volumes of the future markets. The vast majority of trades is conducted without hedging against the risk of differences between the system price and the actual price in the bidding zone of delivery.

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[21] More recent data was not available for this evaluation.

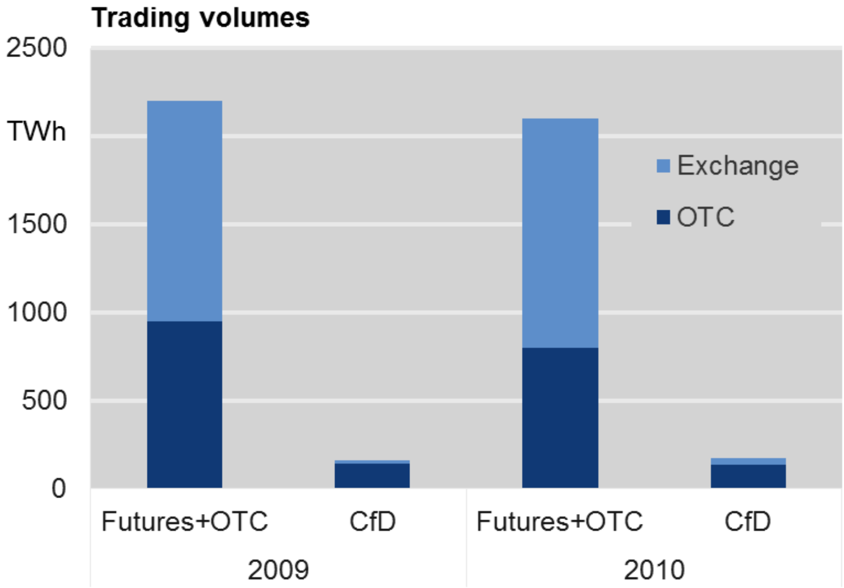

Fig. 4.1: Traded volumes in Futures+OTC versus CfD markets (source: own depiction based on data from NASDAQ OMX)

It appears reasonable to expect that after the Swedish bidding zone was split, liquidity of CfD trading has further declined because of the increased fragmentation of the market (more zones, more borders, more CfD products, but identical total market size). In this respect we analyse the bid-ask spreads of CfDs for two periods of three months length each, one before the split of the Swedish bidding zone (June to August 2010) and a recent period after the split (June to August 2014). CfDs are traded for different terms (year, quarter, month) and lead times. In order to analyse products that should, theoretically, be among the most liquid ones, the evaluation is focused on the respective front month products.

Fig. 4.2 shows that the bid-ask spreads have increased from 2010 to 2014, namely from 0.77 €/MWh to 0.96 €/MWh, i.e. by 25 %. Of course there could be many reasons, which jointly caused this development, but it appears reasonable to assume that the reduction of the average size of bidding zones at least contributed to the increase of the average bid-ask spread.

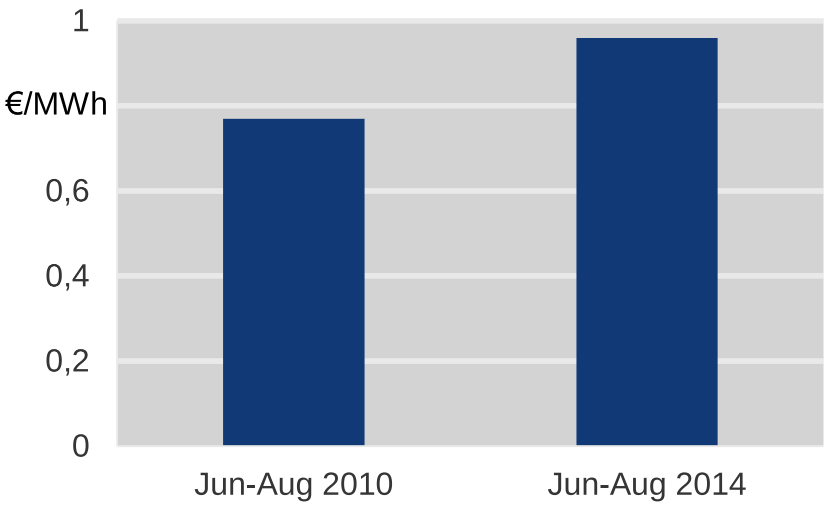

Fig. 4.2: Average bid-ask spread of CfDs in the Nordic market for the respective front month (source: own evaluation based on data from NASDAQ OMX)

Besides this relative increase, also the absolute level of the bid-asks spreads is insightful – in particular when it is seen in relation to the closing prices of the CfDs. In the analysed period from 2014, the average ratio between the bid-ask spread and the closing price of the respective front month products was 29 %. Thus the transaction costs incurred by the market participants amount to a significant share of the price of the product, i.e. of the benefit of trading CfDs in the first place.

The low liquidity of CfDs in the Nordic market has also been reported in a recent Elforsk study [5]. According to that study, "the supply and demand of CfD contracts may be unevenly balanced in some bidding areas due to the underlying characteristics of these areas. In SE4 [i.e. the Southern Swedish bidding zone], the problem is due to too few fundamental sellers and too many buyers. This creates a problem for market players who want a hedge against price differences in these areas. In particular, there is a lack of supply of CfD contracts in SE4 due to the production deficit in this area."

So liquidity of the hedging products is particularly low just when (and because!) a bidding zone has a structural imbalance, i.e. when export from or (in the above example) import to a bidding zone is very relevant. It is interesting to note that the study refers to the situation after the split of the Swedish bidding zone – the situation of structural import of the SE4 zone is a concrete result of this split. Hence, the Elforsk study, in conjunction with the above evaluation of the bid-ask spreads, underpins that a reduction of liquidity in smaller bidding zones is not avoided by the fact that, in principle, hedging products exist to cope with locational price differences.

5 Conclusions

The study shows that some of the idealistic assumptions under which smaller bidding zones are sometimes believed to yield welfare benefits are wrong. A refined application of numerical simulations of scheduled and re-dispatch has been undertaken, with an emphasis on uncertainties. In particular, uncertainties regarding the amount of commercial transmission capacity on newly introduced bidding zone borders and uncertainties regarding the temporal course of network expansion have been investigated (fig. 5.1).

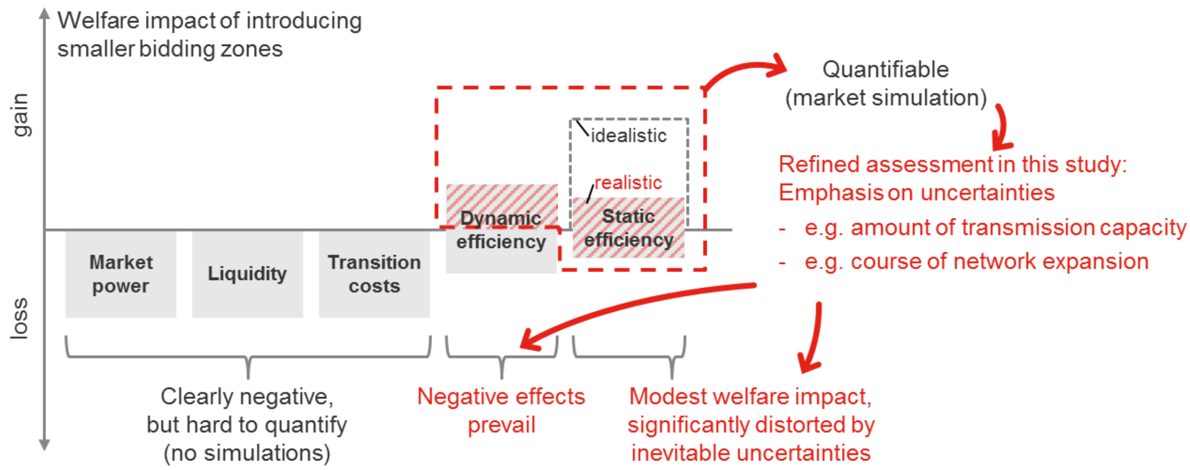

Fig. 5.1: Consequences of introducing smaller bidding zones on various welfare aspects, and (in red) focus and outcome of numerical assessment in this study

- The results indicate that the impact of downsizing bidding zones on **static efficiency** is relatively modest, with unclear sign. This is due to the two main effects: Firstly, changes of scheduled dispatch costs (efficiency of zonal market) and of re-dispatch costs largely level out each other. Secondly, introducing smaller bidding zones does not entirely remove the need for re-dispatch, and it can even give rise to new congestion inside the smaller zones, which locally increase re-dispatch costs.
- Regarding **dynamic efficiency**:
  - **Network expansion** affects the suitability of bidding zone configurations. The numerical assessment shows that the uncertain timing of network expansion reduces the efficiency of re-configuring the bidding zones, because there is a strong risk that network development and bidding zone configurations will be out of sync. This finding from the

numerical assessment adds to a set of qualitative arguments why the dynamic efficiency of introducing smaller bidding zones tends to be negative.

- **Investment incentives with respect to network expansion** are reduced by introducing smaller bidding zones. Smaller zones can be understood as a means to administer congestion, thereby avoiding the need to expand the network, although this may be more efficient. In larger bidding zones, there is a clear incentive to expand the network in order to reduce the operational and cost burden of re-dispatch.
- Zonal price differences provide only weak **incentives for efficiently locating generation and load**. Moreover, alternative measures exist to achieve this, if desired.
- Re-configuring bidding zones would yield significant **transition costs**, since numerous market and operational processes would be affected. Introducing smaller bidding zones would yield higher transition costs than merging of existing bidding zones.

- Smaller bidding zones tend to reduce liquidity and increase market power issues, which would result in a welfare loss. Efficient management of the transmission capacity between the bidding zones, i.e. capacity allocation and provision of financial hedging instruments, cannot avoid these effects: The purpose of re-configuring bidding zones is to impose restrictions of power transfer between these zones on the market participants, and this is the fundamental reason why liquidity and market power are affected in a negative way.

The above findings can be summarized by the conclusion that under realistic conditions (in particular accounting for uncertainties), the introduction of smaller bidding zones is unlikely to yield a positive total welfare impact.

We would like to note that the above conclusions are drawn under the condition that, in order to accommodate the politically desired transformation of the power system towards carbon-neutrality, sufficient network investment will be realised in terms of time and quantity. As we have shown in the analysis of dynamic efficiency above, large and stable bidding zones help to stipulate network investment. But if endeavours for (efficient) network investment are not successful within the next years, introducing smaller – but stable – bidding zones might become necessary as last resort. This is because if the demand for curative congestion management (e.g. re-dispatch) became excessive, network security would be put at risk. Moreover, market based processes would then only account for an ever dwindling share of the final outturn dispatch.

However, such formation of smaller bidding zones as last resort would not yield higher welfare, but make the transformation of the power system towards carbon-neutrality much more expensive: The development of renewable power sources would have to be adapted in a cost-increasing manner – more even geographic spread, less off-shore, more decentralized (PV) capacity, more total installed capacity for same energy production (due to more frequent curtailment of infeed) –, and the power market would operate with lower efficiency.

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Annex

A Numerical models used for efficiency assessment

A.1 Overview

In section 3.1.1 we have outlined that the variable costs of power supply depend on the final outturn dispatch, and that we apply two simulation stages in order to determine the final outturn dispatch and its respective costs. Fig. A.1 shows the evaluation process for a predefined bidding zones configuration.

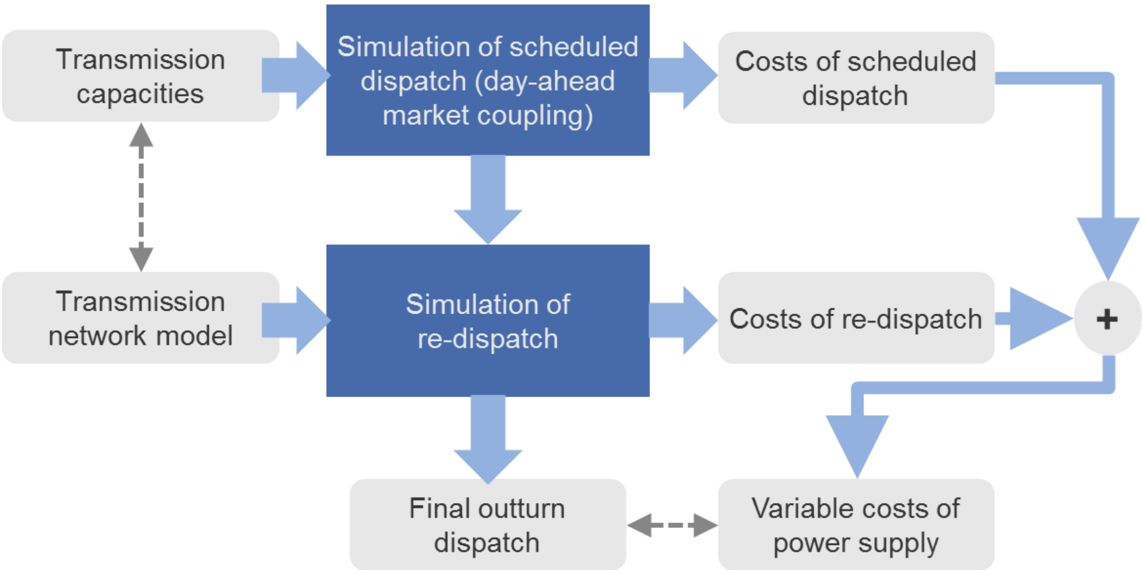

Fig. A.1: Evaluation process for a predefined bidding zones configuration

In the first step a market simulation (simulation of scheduled dispatch) is carried out. The market simulation considers commercial transmission capacities between the predefined bidding zones and thus neglects transmission limitations within the bidding zones. The transmission capacities are expressed in terms of NTC values. The market simulation determines the cost-optimal hourly dispatch of the power generation units and, therefore, the minimum total costs of scheduled dispatch.

In a second step the results of the market simulation are checked for compliance with the technical transmission network limitations. If one or more network elements are overloaded as a consequence of scheduled dispatch, re-dispatching measures are determined for the respective hour(s) in order to make sure that the final outturn dispatch does not lead to overloading of the network. This is done such that the costs of adjusting the scheduled dispatch (i.e. the re-dispatch costs) are minimized. The sum of the costs of scheduled dispatch and re-dispatch are the variable costs of power supply, which are the costs of the final outturn dispatch.

In the following sections the approaches used for the market and the re-dispatch simulations are discussed in more detail.

A.2 Market simulation

The following section gives an overview of the market simulation method and its parameterization for this study.

Overview of the method

Fig. A.2 shows an overview of the market simulation method. It calculates the cost-minimal unit commitment in an hourly time pattern for a full year in closed form. The objective function is to minimize the costs of dispatchable generation units. Strictly speaking, only dispatchable thermal power plants contribute to the objective function. They are characterized by fuel type, CO_2 emissions and efficiency.

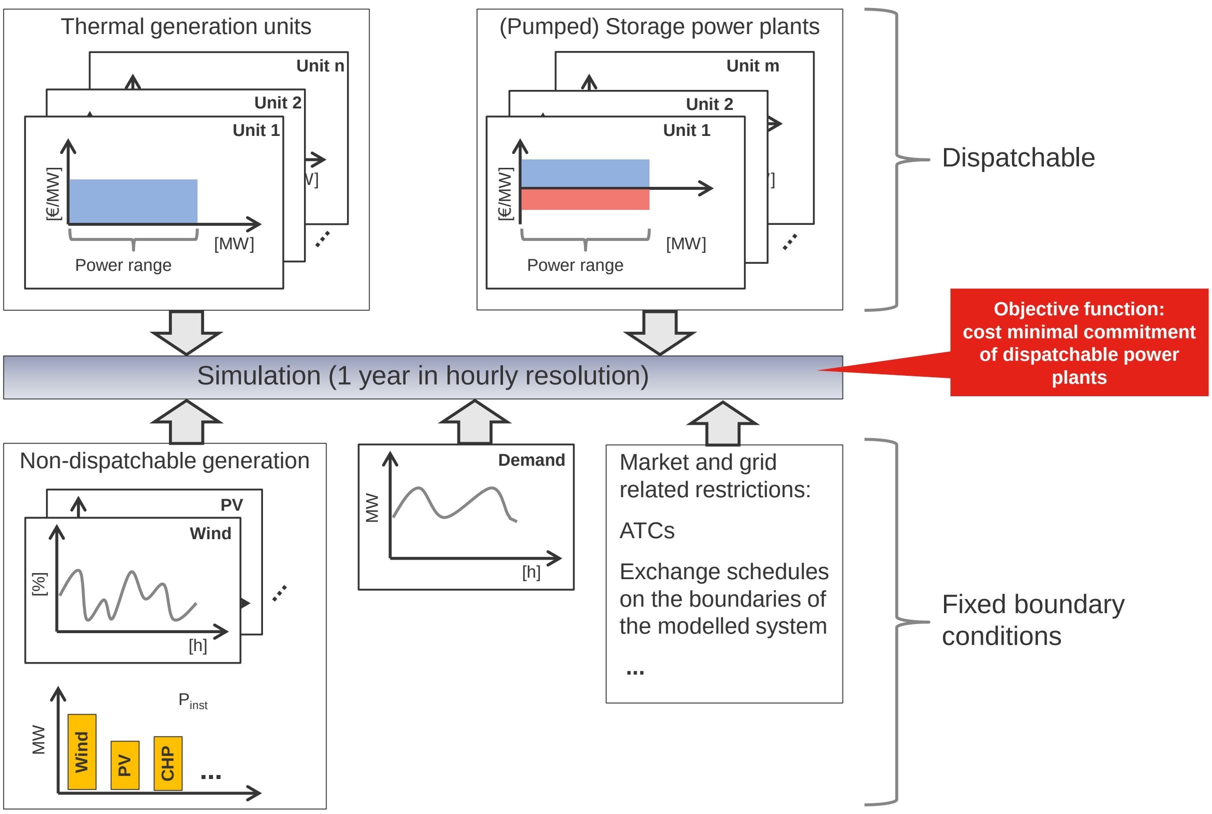

Fig. A.2: Schematic overview of the market simulation

In addition, (pumped) storage power plants are dispatchable, and their dispatch, like that of the dispatchable thermal plant, is an endogenous decision of the simulation. However, (pumped) storage power plants only indirectly contribute to the objective function. This contribution results from the optimal use of the respective reservoir. The added value arises from the replacement of (thermal) generation units that incur marginal costs. By operating in pump mode in times of low marginal costs and operating in turbine mode in times of high marginal costs, a partial substitution high cost thermal power plants is achieved, which leads to a decrease of total variable costs.

The minimization of the objective function is subject several constraints. For the hydro-thermal power plants the linear optimization approach is able to consider maximum technical generation levels. Further the operation of hydro-thermal power plants requires the consideration of intertemporal constraints. (Pumped) storage power plants are limited because of their water reservoirs (reservoir size and course of natural inflow). These intertemporal constraints can be considered within the linear optimization problem. In case of thermal power plants the intertemporal conditions – minimum power as well as minimum on and off times – lead to non-linear conditions. A semi-heuristic approach consisting of three steps ensures that the non-linear conditions are properly considered:

- First the linear optimization problem is solved.
- Secondly, violated intertemporal constraints of thermal power plants within the results of the linear optimization problem are “repaired” by a heuristic approach. It generates additional constraints for the thermal plants (e.g. forcing off for minimum off time or imposing minimum power instead of zero during minimum on time) in order to enforce fulfilment of the intertemporal constraints.
- Lastly, the linear optimization problem is solved once again under consideration of the additional constraints with respect to the thermal power plants.

In addition to the constraints on dispatchable power plants, fixed boundary conditions have to be considered. This comprises must-run generation, demand as well as market and grid related restrictions. Wind turbines, solar power units and combined heat-and-power units are the power sources modelled as must-run within the simulation. Must-run productions are given by exogenous predefined hourly distributions. In combination with the given time series of demand the simulation calculates the residual load, which forms the equality condition for the constraint of covering the (inelastic) demand.

The exchange schedules between the assumed bidding zones are an endogenous decision of the simulation, subject to their respective limitations (NTC values). Power exchange with bidding zones beyond the modelled system is considered by predetermined exchange schedules.

Parameterization of the simulation

The simulation is parameterized for the historic situation of 2013. Data on thermal generation is based on a commercially available database from Schneiders and Kuhs[1] which considers European power plants greater than 100 MW. It has been expanded using information from publicly available sources. Renewables Energy supply stems from publications by the TSOs. Further information, such as NTCs and demand time series, have been obtained from the public database of the European Network of Transmission System Operators for Electricity (ENTSO-E). Data for combined heat and power is based on information from Eurelectric.

A.3 Re-dispatch simulation

Fig. A.3 shows an overview of the re-dispatch simulation with the main input and output parameters. In the next sections the steps of load flow model creation, load flow and contingency analysis and congestion management are described.

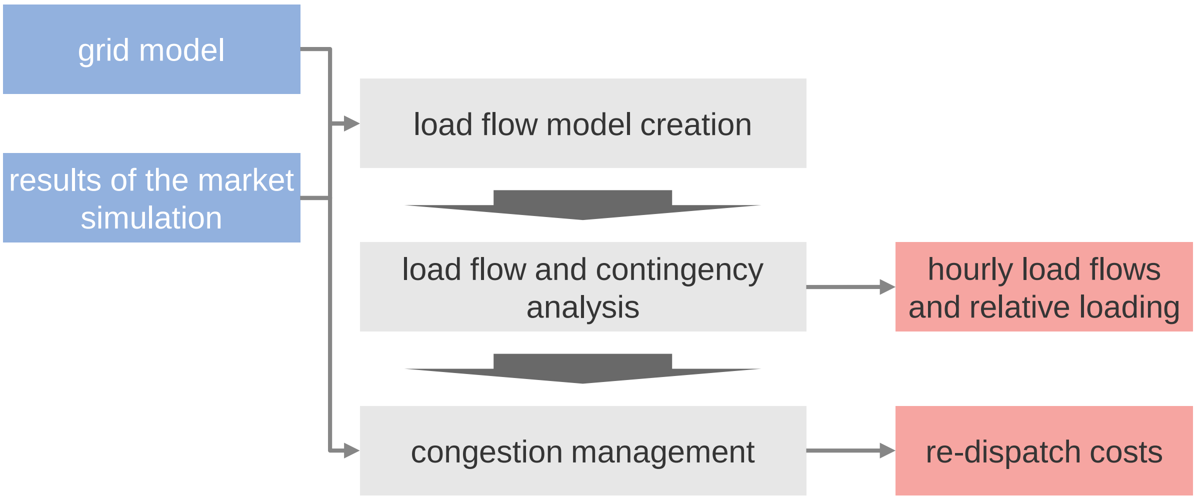

Fig. A.3: Overview of the re-dispatch simulation with the main input and output parameters

[1] http://www.kraftwerkskarten.de/Home

Load flow model creation

The re-dispatch simulation uses a grid model the European transmission grid, which is based on publicly available data and therefore is free from third parties' intellectual property rights. Experience from past project confirms that the model is suitably accurate for such types of investigation.

The load flow model is created by merging the market simulation results with the grid model. Each node receives information about supply and demand for each hour in the considered time period, in this case for 8760 h. The allocation of generation schedules to network nodes is based on block-wise information for Germany. In other countries, the aggregated generation power of generator groups is distributed among several network nodes, respectively.

Load flow and contingency analysis

The load flow models for each individual time slot represent the input parameters for the load flow and contingency analysis.

The most relevant figure in a contingency analysis is the active flow on the network elements. The active flow impact caused by an outage – so-called (n-1) situation – can be calculated in a simplified manner by means of linear line outage distribution factors (LODF) [6]. By combining "normal" (AC) load flow calculation for each hourly base case with LODF based contingency analysis, an appropriate compromise between calculation time and accuracy is achieved.

The main results of the contingency analysis for the current study are the hourly active load flows and relative loading of the considered lines. If the relative loading exceeds 100 %, the next step (congestion management, i.e. re-dispatch) is triggered for the respective simulation hour.

Congestion management

The basic idea of re-dispatch is to determine a modification of the geographical generation distribution in order to cause a change in the flow situation such that congested lines (i.e. lines that would be overloaded after an outage) are relieved. A redistribution of generation is achieved by decreasing generation in one set of nodes and an increase of generation in another set of nodes. The absolute amount of generation decrease and increase is equal (neglecting the change in losses). Although the amount of generated power is equal before and after re-dispatch this approach is not free of costs. Since the generation dispatch before re-dispatch is cost minimal (within the modelling framework of the market simulation), a redistribution of generation generally causes more costly generators to increase and less costly generators to decrease their output. The objective of the re-dispatch step is to obtain a congestion-free grid while minimizing the inevitable increase of generation costs.

The impact of a change in generation on the active flow over transmission lines is modelled by linear sensitivity factors. On this basis it is possible to perform a re-dispatch simulation by solving a linear optimization problem.

The contributions of generators to the objective function are, in principle, identical to the market simulation. The infeed of renewable generators can be curtailed, but only after the possibilities of conventional plants are exhausted.

The optimization is subject to several constraints. First of all the optimization variables (i.e. changes of generation output) must stick to the individual generation capacities. This means that the generators are allowed to increase or decrease their power generation only within their predefined power range. This range is dependent on the operation of the generator within the considered hour, which is obtained from the results of the market simulation. Since the re-dispatch is calculated on an hourly basis, intertemporal limitations of (pumped) storage plants are considered in a heuristic way.

Further a balance neutral re-dispatch is required, i.e. the total increase of generation has to be equal to the total decrease of generation. Also, the load flow constraints must be respected, i.e. the product of generation change and network sensitivities must lead to a congestion-free situation. Furthermore, the cross-zonal transmission capacities must be respected.

The results of the congestion management step are the amount of re-dispatch energy and the re-dispatch costs for each hour of the year and, consequently, the total annual re-dispatch costs.