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Flow-based market coupling: What drives welfare in Europe's electricity market design?

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Flow-based market coupling – What drives welfare in Europe's electricity market design?

HEMF Working Paper No. 08/2019

by

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Abstract

Due to the call for further integration of European markets and the targeted climate goals, both European electricity systems and markets have undergone continuous changes over the last few decades. As part of these developments, the so-called Flow-Based Market Coupling (FBMC) superseded the previous net-transfer-capacity-based approach in Central Western Europe in 2015, aiming at a better representation of physics of the electricity grid as well as increased transparency of market results and procedures. Yet, the market coupling procedures have recently been exposed to criticisms questioning their transparency in aspects such as the determination of FBMC parameters, such as generation shift keys (GSKs) or selected critical branches. At the worst, doubts are even cast on realized welfare increases through FBMC. The paper at hand investigates the FBMC approach by analyzing the market outcomes as well as the corresponding redispatch requirements under different premises and FBMC varieties. Inter alia, results show that different GSK approaches have a significant effect when price zones are well-defined, i.e., when intra-zonal congestion is excluded. In the contrary case, GSK choices have less – or even statistically nonsignificant – impact. Furthermore, we show that FBMC is rather insensitive to forecast deviations of renewables infeed. However, changes to the remaining available margins and the selection of critical branches – as being proposed by regulators and the European Commission, respectively – can severely affect results in terms of redispatch quantities and overall welfare.

Keywords : Flow-based market coupling; Zonal pricing; Nodal pricing; Generation shift keys; Remaining available margin; Electricity grid modeling; Electricity market modeling; Electricity market design; Congestion management; Welfare analysis.

JEL-Classification : Q40 (energy general), Q41 (Energy - demand supply prices), Q43 (energy macroeconomy), Q49 (Energy - other), C60 (Mathematical Methods, Programming Methods, Mathematical and simulation models - general)

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Abbreviations

CB	Critical Branch
CEE	Central Eastern Europe
CWE	Central Western Europe
EMCP	Electricity market clearing problem
Entso-E	European Network of Transmission System Operators
FAV	Final adjustment value

FBMC	Flow-Based Market Coupling
FRM	Flow Reliability Margin
GSK	Generation Shift Key
HVDC	High-Voltage Direct Current
LFC	Line Flow Constraint
NTC	Net Transfer Capacity
OPF	Optimal Power Flow
PTDF	Power Transfer Distribution Factor
PZC	Price Zone Configuration
RAM	Remaining available margin
RD	Redispatch
RES	Renewable Energy Sources
TSO	Transmission System Operator
vRES	Variable Renewable Energy Sources

Nomenclature

\mathcal{F}^{CB}	set of critical branches
$f \in \mathcal{F}$	index / set of transmission lines
$i \in I_{(z)}$	index / set of nodes (with subscript z : set of nodes within zone z)
$z \in Z$	index / set of price zones
$\Delta F_f^{\text{ref},(e)}$	expected difference in reference flows on line f
ΔF_f^{ref}	difference in reference flows on line f
Δq_i	nodal net export at node i
$\Delta g_i^{+/-}$	change of generation in the redispatching process
$\lambda_{z,i}^{(p)}$	predetermined weight for zonal PTDF calculation at node i in zone z (=GSK)
$\tilde{a}_{f,z}$	zonal power transfer distribution factor of line f in zone z
β^+, β^-	penalty factor for redispatch model
$a_{f,i}$	nodal power transfer distribution factor of line f at node i

$b_{z,i}$	node-to-zone allocation value, which is 1 if node i is part of zone z and 0 otherwise
C_f	transmission line capacity of line f
c_i	variable generation cost function at node i
d_i	vertical load at node i
F_f^{adj}	final adjustment value of f
$F_f^{\text{nsdf},75}$	adjustment term assuring that RAM of line f constitutes at least 75 % of its line capacity in standard flow direction.
$F_f^{\text{sdf},75}$	adjustment term assuring that RAM of line f constitutes at least 75 % of its line capacity in non-standard flow direction.
g_i	aggregate electricity generation at node i
g_i^{max}	aggregate generation capacity of generation units at node i
g_i^{*z}	aggregate generation at node i of the zonal EMCP
M_f	flow reliability margin of f
N	number of nodes in the system
N_z	number of nodes in zone z
\tilde{q}_z	zonal net exports of price zone z
q_i	nodal export at node i
$q_i^{(e)}$	expected nodal export at node i
R_f^{nsfd}	RAM in non-standard flow direction
R_f^{sfd}	RAM in standard flow direction

1. Introduction

In Europe, the ongoing discussion about the design of electricity markets has been sparked again by the call for further integration of national electricity markets and the need for an improved integration of the growing infeed of variable, non-dispatchable renewables. The situation is especially characterized by steeply increasing redispatch (RD) amounts and costs. In this respect, the market coupling mechanism constitutes one major focus of the debate. In theory so-called nodal pricing as implemented in large parts of the USA is frequently referred to as the optimal solution. In numerous studies, advantages of nodal pricing have been pointed out (cf. Schweppe et al. 1988; Hogan 1992; Bjørndal and Jørnsten 2001; Ehrenmann and Smeers 2005; Bjørndal and Jørnsten 2007). Yet Europe still employs zonal market coupling, where most national borders coincide with price zone borders. Until 2015, a Net-Transfer-Capacity (NTC)-based approach was applied to couple electricity markets. In order to achieve a better representation of physical constraints of the electricity grid, flow-based market coupling (FBMC) has been introduced for Central Western Europe (CWE). A comparison of both mechanisms is given in Plancke et al. (2016). In contrast to the NTC-based approach, FBMC approximates physical flows induced by commercial exchanges between market participants (details are explained sec. 2). In particular, net positions of market participants are translated into load flow approximations via zonal power transfer distribution factors (PTDF). This is similar to the well-known concept of DC-lossless load flow calculations, which are used for load flow assessments or market clearing in nodally-organized markets. Instead of using nodal net injections and withdrawals (as in the DC-lossless load flow), the FBMC approach relies on an expected distribution of generation shifts, which are given by so-called generation shift keys (GSKs). The resulting expected load flows are then limited by so-called remaining available margins (RAMs). These RAMs (and the corresponding load flow approximation) apply for a subset of lines, which are named critical branches (CBs). These parameters determine the feasible region of the electricity market clearing problem (EMCP), often denoted as the flow-based domain. This further introduction of physics into the market clearing process – although not comprehensive – was meant to increase the utilization of grid capacities, ultimately improving welfare and price convergence.

Various reports have acknowledged that FBMC contributes to achieving the goals stated above (cf. Amprion et al. 2015; Bergh et al. 2016; ACER 2017; Amprion 2017). Welfare gains are said to be realized, since the volume of the flow-based domain increased in comparison to the previously applied NTC-based approach. Given these improvements, even an extension of the FBMC methodology to Central Eastern Europe is planned for 2020 (cf. Amprion et al. 2018). Potential benefits of the extension are reported in Marjanovic et al. (2018). However, criticisms have also been expressed in the existing literature. In particular, we have identified four frequently-debated features which lead us to key research questions for this paper:

1. **Use of heuristics:** In the process of determining GSKs, numerous computation procedures are allowed. The European Network of Transmission System Operators (Entso-E) suggests up

to five different methods (Entso-E 2017). Which procedure is applied in each control area is at the discretion of the corresponding transmission system operator (TSO). These circumstances are criticized as being nontransparent (cf. CREG 2017) and the matter is picked up by Dierstein (2017), Finck et al. (2018), and Sebestyén et al. (2018) who investigate effects of GSKs. While results in Dierstein (2017) show rather small effects of different GSKs on welfare of the day-ahead market and Finck et al. (2018) identify relatively small generation changes on country level caused by different GSK approaches¹, Sebestyén et al. (2018) conclude that a harmonization of GSKs has significant influence on welfare.² Similarly, ACM et al. (2015) state the need for additional investigations of different GSK approaches. These and further references³ show that the concept of GSKs is taken up by various researchers. However, a comprehensive assessment of GSKs is missing. In terms of model-based assessments, results do not consider the effects on overall system costs, i.e., the aggregate costs of both day-ahead market clearing and redispatch. Yet, the need for the additional consideration of redispatch is identified in Dierstein (2017) and Finck et al. (2018). Thus, we raise the following research question: ***How dependent is the efficiency of FBMC on the chosen GSK method?***

2. **Process-induced uncertainty:** Since the very beginning of FBMC, process-induced uncertainties have been known to exist (cf. Amprion et al. 2014). Felten et al. (2019) illustrate why the FBMC process implicates uncertainties. In particular, the authors explain that forecasts of the power system are made two days before delivery and how the resulting deviations from these forecasts may entail either redispatch (RD) or welfare losses. Thus, there are inefficiencies in FBMC, which gives rise to the second research question: ***To what degree are FBMC results sensitive to forecast errors?***
3. **Imperfect price zones:** Ideally, price zones of zonally organized electricity markets should be free of internal bottlenecks (cf. EFET 2018). Consequently, congestion of intra-zonal transmission lines and RD due to scheduled intra-zonal line overloads should ideally be rare events. However, this ideal situation is not the case in CWE, and RD due to intra-zonal line overloads is rather common with the current price zone delimitations (BNetzA and BKartA 2018, cf.). Therefore, improved price zone configurations have been proposed (cf. Burstedde 2012; Breuer 2014; Kłos et al. 2014; Entso-E 2018b; Felling and Weber 2018). Our focus is related, though slightly different. Instead of investigating new price zone configurations, we focus on FBMC performance and pose the following research question: ***How do imperfect price zones, i.e., zones with intra-zonal bottlenecks, impact the performance of FBMC?***
4. **Adjustments to the capacity allocation process:** The fourth item is somewhat related to imperfect price zones and intra-zonal bottlenecks. If RD is expected due to predicted intra-zonal line overloads, one way of reducing or avoiding this RD may be allocating less line

¹Only for few technologies in single countries, generation changes seem relevant according to Finck et al. (2018).

²Note that the geographical scope of the studies in Sebestyén et al. (2018) and Finck et al. (2018) are limited (i.e., using a detailed grid model for Belgium only or exclusively modeling Germany, Poland and Czech Republic, respectively).

³For example, GSK improvements are suggested in Van den Bergh and Delarue (2016) or Schönheit and Sikora (2018).

capacity to the market coupling process. To this end, the responsible TSO may decide to reduce the RAM of intra-zonal or cross-zonal transmission lines in order to restrict cross-border trade. CREG (2017) and ACER (2017) criticize such actions. Along the same lines, EC (2017) demurs that only 25 % of cross-border line capacities are actually used and names the lacking cooperation of TSOs as one reason for this situation.

A move which would adjust allocated capacities into the opposite direction is made by ACER (2018). After a transition period of two years, RAMs must exceed a certain threshold. The threshold value is formulated relative to the thermal capacity of the line and is set to increase: At least 30 %, 36.67 % and 43.33 % of the line capacity must be allocated to the market coupling process by 2020, 2021 and 2022, respectively. By 2026, the threshold value will be increased to 75 %. However, both TSOs and market participants have raised their concerns about this proposal (cf. EFET 2018; Amprion 2019), as this rule would alter the mathematical soundness of the FBMC algorithm, thereby misaligning markets and physics. Thus, results would deviate from the targeted optimal market outcome. Further approaches to increase trade exist, a straightforward approach being the exclusion of intra-zonal line constraints from the FBMC market clearing problem (cf. ACER 2018).

As both directions of capacity adjustments are criticized, we ask the following questions: ***What are the impacts of adjustments to the capacity allocation process? Are capacity adjustments an expedient means to decrease redispatch or increase cross-border trade?***

Investigation of FBMC is not completely new. For instance, Van den Bergh and Delarue (2016), Dierstein (2017), Finck et al. (2018), Schönheit and Sikora (2018), and Sebestyén et al. (2018) assess the effect of GSKs, while Wyrwoll et al. (2018) and Felling et al. (2019) investigate different FBMC parametrizations of considered branches and security margins. The role of forecast errors is only examined in Felling et al. (2019). The literature listed above, however, does not assess FBMC in a comprehensive manner, and the need for further investigations of FBMC is seen by Dierstein (2017), Finck et al. (2018), Marjanovic et al. (2018), and Wyrwoll et al. (2018). In the following, we summarize in which way this paper exceeds the existing literature and what its novelties and contributions are, clustering these advances in three groups:

Firstly, this paper uses an integrated model that is capable of modeling nodal pricing, replicating FBMC procedures and its use in the market clearing process as well as determining the subsequent RD quantities and costs. Especially two of these elements, the benchmark to the nodal pricing solution and the consideration of redispatch, are frequently omitted in the analyses mentioned above. However, both of these aspects are important elements for interpreting or even determining overall welfare, respectively.

Secondly, the proposed framework enables us to investigate all the above-mentioned elements and adjustments of FBMC in a ceteris paribus approach and therefore to isolate the effects of single elements. In large-scale system models, this ceteris paribus characteristic is rarely given (cf. Felling et al. 2019). This feature of our paper is further strengthened by statistical tests for significance of

individual FBMC adjustments. This way of interpreting and substantiating FBMC analyses has not been found in existing literature. Thus, we offer well-founded conclusions on the true levers of the FBMC process, thereby shedding light on previously contradicting opinions and findings.

Thirdly, we develop a novel way of evaluating the overall performance of FBMC. By using the first-best solution (i.e., the nodal pricing solution) and the results of a market clearing without trade limitation, we derive a range of the performance of market coupling methodologies. By contrasting the FBMC results to these extreme options, we draw conclusions on FBMC's relative performance. Notably, this relative performance is not only assessed in an ideal scenario but also in a setting with imperfect price zones.

The remainder of this paper is structured as follows: Section 2 introduces the developed methodology. This includes the explanation of the two basic modeling approaches – the electricity market clearing problem using nodal pricing and FBMC-style zonal pricing. Moreover, we present the details of FBMC and our approaches to model the FBMC elements and to assess the debated FBMC features and adjustments. Subsequently, sec. 3 presents the numerical assessments which address the above research questions. Finally, we conclude with a discussion of the results and draw the main conclusions (cf. sec. 4).

2. Methodology

This section presents the methodology used for assessing FBMC. In first instance, we provide a qualitative overview of the principle differences between a nodal pricing regime and CWE-style zonal pricing⁴ and their mathematical formulation. Subsequently, we introduce the characteristics and elements of FBMC (cf. sec. 2.2). Finally, we explain how we model and assess the essential FBMC features that are subject to the research questions from sec. 1.

2.1. Basic modelling approach

We start the introduction of the basic modelling approach by identifying the basic differences between zonal and nodal pricing regime. The major differences are visualized in fig. 1 and 2.

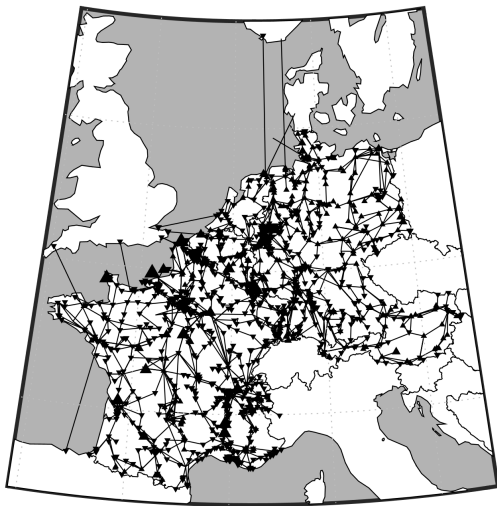


Figure 1: Illustration of information and line flow constraints used in a nodal pricing regime.

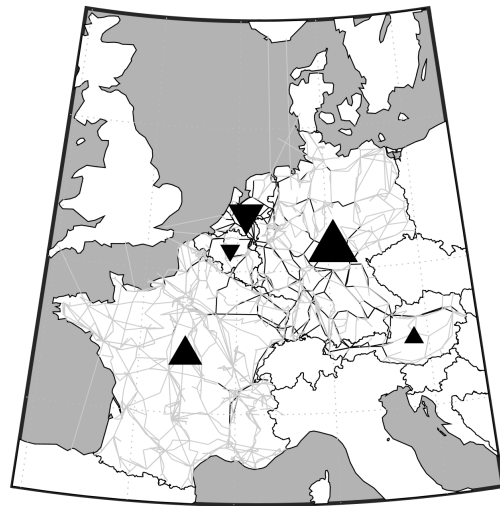


Figure 2: Illustration of information and line flow constraints used in a FBMC-style zonal pricing regime.

In fig. 1, triangles symbolize nodal net exports (upturned triangles) and nodal net imports (downturned triangles).⁵ The nodal net export at node i is denoted by q_i . In a nodal EMCP, the market clearing entity has full knowledge of bids and asks at nodal level and the clearing is performed at this granularity. Likewise, the line loadings of all lines of the transmission grid are considered. Given the nodal net exports, these line loadings can be determined using the laws of Kirchhoff. Fig. 2 illustrates the information used by the zonal EMCP. In contrast to nodal pricing, FBMC only

⁴Henceforth, when we mention zonal pricing, we always refer to the zonal pricing using the FBMC algorithm that is implemented in CWE.

⁵For brevity, we only refer to net exports henceforth, implying that negative net exports are understood as net imports.

considers net exports at zonal level. These zonal net exports \tilde{q}_z are simply the sum of the nodal exports within one price zone ($\tilde{q}_z = \sum_{i \in I_z} q_i$, where I_z denotes the set of nodes within zone z). In terms of line flow constraints (LFCs), FBMC only considers a set of selected transmission lines, the so-called critical branches (CBs). On the one hand, the set of CBs includes all cross-zonal lines. In addition, internal branches may be included in the set of CBs – based on certain criteria, which are discussed in sec. 2.2.2. The line loadings of the CBs are approximated using the information available, which mainly consists of the information on net exports aggregated at zonal level.

2.1.1. The electricity market clearing problems

Under the assumptions mentioned in appendix A, the electricity market clearing problems (EMCPs) can be equivalently formulated as system-wide cost minimization. Subsequently, we describe the optimization problems for the nodal and the zonal EMCP. Many of the terms of these problem formulations are identical. Thus, we start with explaining the common terms and continue with the description of constraints which only apply to the nodal EMCP or the zonal EMCP.

Common terms in the nodal and zonal EMCP: The objective function of all regarded EMCPs is given by eq. (1). Its objective is the minimization of the system costs (i.e., the sum of products of the variable generation costs c_i and the electricity output g_i at node i for all nodes $i \in I$). The variable costs c_i only depend on the states of generators at the corresponding node i . The aggregate output of these generators is g_i . Thus, there is a monotonously increasing functional relation $c_i = f(g_i)$, which we do not specify further.⁶ Δt denotes the duration of the considered time step.⁷

Eq. (2) simply expresses the convention that the surplus of electricity output (i.e., generation g_i minus vertical load d_i at node i) constitutes the nodal net export q_i . Eq. (3) assures that the overall generation meets demand. Eq. (4) expresses the upper and lower generation limits at all nodes. Thus, the limiting value g_i^{\max} is the aggregate generation capacity of generation units at node i .

$$\min_{g_i} \sum_{i \in I} c_i g_i \Delta t \quad (1)$$

$$\text{s.t.} \quad q_i = g_i - d_i \quad \forall i \in I \quad (2)$$

$$\sum_{i \in I} q_i = 0 \quad (3)$$

$$0 \leq g_i \leq g_i^{\max} \quad \forall i \in I \quad (4)$$

As stated above, eq. (1) to (4) apply no matter if market coupling (MC) is achieved on a nodal or zonal basis.

⁶However, in the latter application, we apply linear cost functions.

⁷Throughout this paper, we consider hourly time steps.

Line flow constraints of the nodal EMCP: In the nodal EMCP, physical line loading behavior and its limits are basically translated to trading restrictions. Thus, each nodal net export q_i has an effect on the loading of lines. Under the assumptions in sec. A, the line loads are a linear function of the nodal net exports. The linear coefficients of this function are the (nodal) PTDFs (in formulae: $a_{f,i}$). For instance, an additional exchange of 1 MW between node i and an arbitrarily-chosen reference node causes an additional line load of $a_{f,i}$ MW on line f . Thus, the inner term of eq. (5) – the superposition of all these increments – describes the loading of line f . C_f is the transmission line capacity, which must not be exceeded for all lines f in the set of all transmission lines \mathcal{F} .⁸

$$-C_f \leq \sum_{i \in I} a_{f,i} q_i \leq C_f \quad \forall f \in \mathcal{F} \quad (5)$$

On the one hand, eq. (5) describes the physical behavior/constraints of the grid and, therefore, it describes the feasible region of the transmission grid states. On the other hand, these physical constraints can be considered directly in the market clearing process, as it is done under a nodal market design. We refer to these constraints as nodal line flow constraints (LFCs). The full PTDF matrix has the rank $N - 1$ with N being the number of nodes in the system.

Line flow constraints of the zonal EMCP: The CWE electricity markets are based on a zonal market design. Therefore, the market coupling (i.e., the process of using the grid to exchange electricity between market areas) is also organized using zonally aggregated quantities. The zonal LFCs approximate power flows based on zonal net exports \tilde{q}_z . Each of these zonal net exports is simply the sum of net exports at nodes within zone z ($\tilde{q}_z = \sum_{i \in I_z} q_i$, as illustrated in fig. 2 above). Thus, zonal LFCs are described in the following way (also see Amprion et al. (2011)):

$$R_f^{\text{nsfd}} \leq \sum_{z \in Z} \tilde{a}_{f,z} \tilde{q}_z \leq R_f^{\text{sfd}} \quad \forall f \in \mathcal{F}^{\text{CB}} \quad (6)$$

In accordance with the use of zonal net exchanges \tilde{q}_z , zonal PTDFs $\tilde{a}_{f,z}$ need to be constructed. For now, we regard $\tilde{a}_{f,z}$ as given. In sec. 2.2.2, we explain how the coefficients $\tilde{a}_{f,z}$ are determined in practice. The limits in eq. (6) are called remaining available margins (RAM) and are given for the standard flow direction R_f^{sfd} and the non-standard flow direction R_f^{nsfd} . The calculation of these limit values is explained in sec. 2.2.2. As explained in sec. 2.1, the zonal LFCs are only applied to the set of CBs $\mathcal{F}^{\text{CB}} \subseteq \mathcal{F}$.

2.1.2. Redispatch

The aggregation in the zonal market design leads to inaccuracies concerning the physical state of the grid as represented by the zonal approximation. Because of these inaccuracies, feasible

⁸Positive and negative flow directions are chosen by convention. Henceforth, we refer to the positive flow direction as standard flow direction (sfd) and to the negative flow direction as non-standard flow direction (nsfd).

solutions of the zonal EMCP will – in many cases – be infeasible in the nodal EMCP. In these cases, *redispatching* of generators will be required. Redispatching entails increasing the energy production of a power plant on one side of a congested element and decreasing the energy production of a different power plant on the other side, thereby changing the power flow across the congested network element. The costs of the additional production by the power plant increasing its production will partly be offset by the cost savings of the other power plant decreasing its production. However, the power plant with the increase in production will usually be more expensive than the power plant with decreasing production – otherwise it would have produced from the beginning.

The starting point for formulating the objective function of the redispatch EMCP and its constraints is the nodal problem as described in equations (1) - (5). However, instead of optimizing the system from zero, the approach is to fix the generation as calculated in the zonal optimization and introducing the new variables Δg_i^+ and Δg_i^- to denote the change of generation in the redispatching process in both positive and negative direction. The division in separate variables for positive and negative changes is done to enable differing costs for positive and negative changes while preserving the linear nature of the objective function. Fixing the generation of the zonal optimization is accomplished by subtracting the zonal generation g_i^{*z} from the demand on each node d_i . Additionally, several potential spots for penalty factors are added. The factors β^+ and β^- can be used to modify costs relative to their amount, while γ is added to every cost term for positive changes in generation and subtracted from every cost term for negative changes in generation. It therefore increases the cost of positive changes and reduces the gains for negative changes equally for all generators and can be understood as a penalty for any redispatched quantities. When considering the actual values for system costs, γ is excluded to reflect only actual costs. The penalty factors β^+, β^- represent actual inefficiencies and are therefore not excluded in cost considerations⁹

The redispatch problem thus becomes:

$$\min_{\Delta g_i^+, \Delta g_i^-} \sum_{i \in I} ((\beta^+ c_i + \gamma) \Delta g_i^+ + (\beta^- c_i - \gamma) \Delta g_i^-) \Delta t \quad (7)$$

$$\text{s.t.} \quad q_i = (\Delta g_i^+ + \Delta g_i^-) - (d_i - g_i^{*z}) \quad \forall i \in I \quad (8)$$

$$\sum_{i \in I} q_i = 0 \quad (9)$$

$$g_i^{\min} - g_i^{*z} \leq (\Delta g_i^+ + \Delta g_i^-) \leq g_i^{\max} - g_i^{*z} \quad \forall i \in I \quad (10)$$

The line flow constraints in equation (5) stay unchanged.

⁹For the numerical assessment, we set the proportional factors to $\beta^+ = 1.3$ and $\beta^- = 0.8$. This means that increasing production of a power plant costs more than decreasing production of the same power plant returns. The blanket penalty term γ is set to 300 EUR / MW. With this parametrizations, without anticipating results, we achieve realistic redispatch quantities (cf. appendix B)

It should be noted that, without including penalty factors, the result of zonal optimization followed by redispatch always leads exactly to the nodal solution in costs¹⁰. This is because the nodal solution is the most cost-efficient way to satisfy all constraints.

2.2. FBMC characteristics and elements

This section connects the two previous sections 1 and 2.1. That is it gives an overview of the basic procedures of FBMC and presents the formal description of its elements. These FBMC elements have been briefly introduced in sec. 2.1 but the explanation of their calculation / determination seems expedient since the FBMC elements are subject to extensive debates (cf. sec. 1).

2.2.1. Overall FBMC process

Fig. 3 illustrates the sequential process of FBMC. For creating the FBMC parameters a detailed system representation, the so-called base case, is required. Therefore, two-days in advance ("D-2"), the participating TSOs exchange detailed grid models¹¹ that represent their best (estimated) forecast of the day of delivery. In particular, this comprises an estimation of the topology, generation, load and exchange programs. Based on this detailed information, the FBMC parameters, linearised around the determined base case, are generated. Subsequently, one day ahead of delivery ("D-1"), these parameters are used within the FBMC optimization to assess the final dispatch¹², prices and net exchanges (cf. Schavemaker P. and Bourmaud, J. 2008; JAO 2017).

On the day of delivery ("D"), the assessed dispatch is carried out. Eventually, in case of congestions, this dispatch has to be adjusted by redispatch actions in order to prevent congestions or to sustain n-1 security.

2.2.2. FBMC elements

Base case definition: In sec. 2.2.1, we have illustrated the stage-wise FBMC process. The FBMC parameters (RAMs and PTFDs) are determined at the D-2 stage with a so-called base case. The base case comprises the best estimate of the situation on the day of delivery, which includes forecasts for variable renewable energy sources (vRES) infeed, electricity exchanges, load and generation. Usually, this is done based on historical data, e.g., reference situations / days. All FBMC parameters that are introduced in the following subsections result from this base case estimation. Because in the real-world process, the base case definition is based on best estimates of TSOs, a reproduction of the exact procedures is hardly possible. Thus, we apply a methodology that first

¹⁰In terms of quantities, it is possible that different dispatches achieve the same minimal costs.

¹¹the so-called two days congestion forecast "D2CF"

¹²There might be deviations due to the intraday market. However, sec. 2.2.2 explains why the consideration of intraday market is negligible for the purpose of this study.

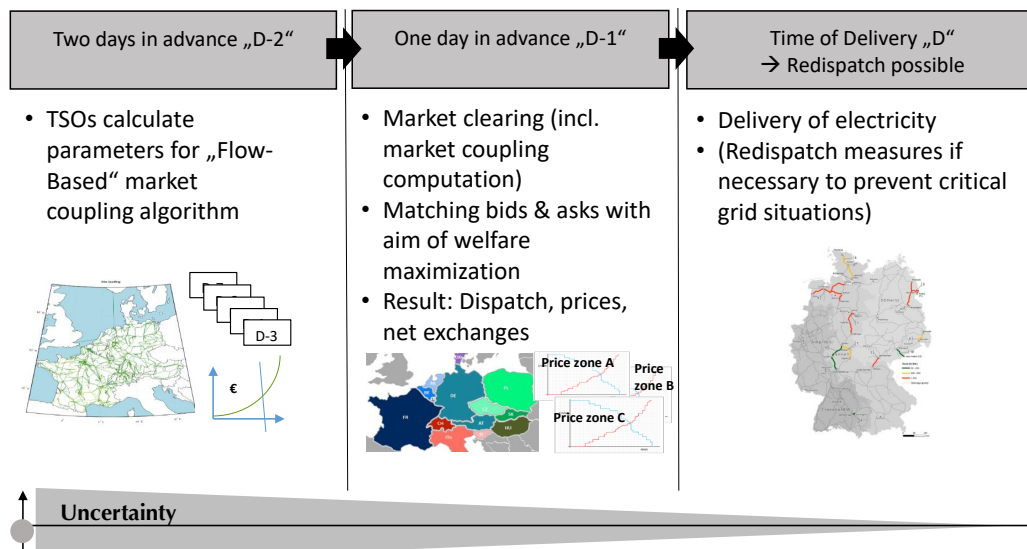


Figure 3: Stages of market clearing in CWE

derives an estimated state of the electricity system and, on the basis of that state, calculates the FBMC parameters. (cf. fig. 4). The system state estimation consists of three steps. It starts with executing an optimal power flow (OPF) calculation. Based on the OPF solution, RAMs and GSKs are calculated and a zonal clearing is simulated. The results of this zonal clearing are used as the *base case*. As the RAMs and, in some cases, the GSKs of the second step are different to those of the final zonal clearing, the base case will diverge from the final market clearing result to some extent. However, a similar divergence will be observed for the real-world estimation procedure.

The procedure is visualized in fig. 4.

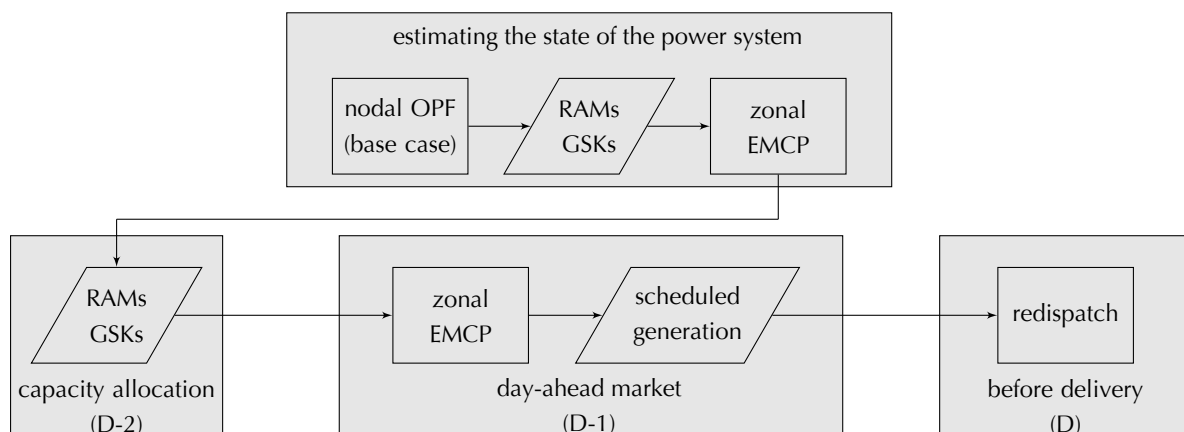


Figure 4: Flow chart for complete simulation run

While we do model imperfect foresight in the base case in some of the scenarios, we always assume perfect foresight from the point of day-ahead market clearing. This means that the day-ahead

market results¹³ contain no uncertainty apart from those potentially introduced by the capacity allocation process (i.e., contained in the RAMs). Consequently, the use of intraday markets to balance forecast errors is not relevant here and subsequently disregarded. It also follows that the results from the nodal optimization are directly comparable with the results from the zonal optimization including redispatch.

Zonal PTDFs: As described in sec. 2.1.1, the CWE-style FBMC requires zonal PTDFs. These zonally approximated line load sensitivities ($\tilde{a}_{f,z}$) are calculated by assigning a weight $\lambda_{z,i}^{(p)}$ to each node and multiplying it with the nodal PTDFs.

$$\tilde{a}_{f,z} = \sum_{i \in I_z} \lambda_{z,i}^{(p)} a_{f,i} \quad (11)$$

These applied weights are the aforementioned generation shift keys (GSKs) that are discussed in the following section.

Generation shift keys: As stated above, GSKs are used to generate zonal PTDFs. When relating the GSKs back to the nodal and zonal LFCs (in eqs. (5) and (6) respectively), they constitute a predetermined share of a nodal net export increase Δq_i in a zonal net export increase $\Delta \tilde{q}_z$ (cf. eq. (12)), where I_z denotes the set of nodes i inside of the zone z .

$$\lambda_{z,i}^{(p)} = \left. \frac{\Delta q_i}{\Delta \tilde{q}_z} \right|^{(p)} \quad \text{with } i \in I_z \quad (12)$$

The superscript (p) indicates that the GSKs are determined before the market clearing has taken place – latest at the D-2 stage. Setting a certain $\lambda_{z,i}^{(p)}$ is equivalent to fixing line load sensitivities for zonal net exports. Dierstein (2017) and Amprion et al. (2014) give an overview of different approaches. Moreover, the European Network of Transmission System Operators (Entso-E) suggests up to five different methods Entso-E (2017). In tab. 1, we collate the most relevant procedures and – similar to Dierstein (2017) – distinguish two groups of GSKs, static and dynamic ones. Static GSKs are calculated based on power system characteristics, which do not alter in a short-term perspective (e.g., installed dispatchable power plant capacities, number of dispatchable power plants). In turn, GSKs are dynamic if their calculation involves variable properties of the power system (e.g., the expected dispatch, expected net exports).

In table 1, u is the index used for power-generating units, $U_{i/z}$ denotes the set of power-generating units at node i / in zone z . $U_{i/z}^{\text{disp}} \subseteq U_{i/z}$ are the corresponding subsets of dispatchable power plants. Furthermore, g_u^{max} denotes the installed electric capacity of unit u , g_u^{min} its technical minimum generation and $g_u^{(e)}$ its expected electricity generation. N_z is the number of nodes within zone z .

¹³This holds for both the zonal EMCP as well as for the nodal EMCP, which we will use as a benchmark.

Table 1: Most relevant GSK determination procedures. In the equations, it is implied that $i \in I_z$.

weighting method	formal description	abbreviation
static calculation		
by installed capacity	$\lambda_{z,i}^{(p)} = \frac{\sum_{u \in U_i^{\text{disp}}} g_u^{\text{max}}}{\sum_{u \in U_z^{\text{disp}}} g_u^{\text{max}}}$	by capacity
by number of generators	$\lambda_{z,i}^{(p)} = \frac{1}{\text{card}(U_z^{\text{disp}})}$	—
by number of nodes	$\lambda_{z,i}^{(p)} = \frac{1}{N_z}$	by N
by flexible capacity	$\lambda_{z,i}^{(p)} = \frac{\sum_{u \in U_i^{\text{disp}}} (g_u^{\text{max}} - g_u^{\text{min}})}{\sum_{u \in U_z^{\text{disp}}} (g_u^{\text{max}} - g_u^{\text{min}})}$	—
dynamic calculation		
by expected generation	$\lambda_{z,i}^{(p)} = \frac{\sum_{u \in U_i^{\text{disp}}} g_u^{(e)}}{\sum_{u \in U_z^{\text{disp}}} g_u^{(e)}}$	—
by available remaining capacity	$\lambda_{z,i}^{(p)} = \frac{\sum_{u \in U_i^{\text{disp}}} (g_u^{\text{max}} - g_u^{(e)})}{\sum_{u \in U_z^{\text{disp}}} (g_u^{\text{max}} - g_u^{(e)})}$	—
by net exports	$\lambda_{z,i}^{(p)} = \frac{q_i^{(e)}}{\sum_{i \in I_z} q_i^{(e)}}$	by NEX

Remaining available margins: As indicated in sec. 2.1.1, RAMs are the limit values which define the flow-based domain. Entso-E procedures describe these RAMs as follows (cf. Amprion et al. 2014):

$$R_f^{\text{nsfd}} = -C_f - \Delta F_f^{\text{ref,(e)}} + F_f^{\text{adj}} + M_f \quad (13)$$

$$R_f^{\text{sfd}} = C_f - \Delta F_f^{\text{ref,(e)}} - F_f^{\text{adj}} - M_f \quad (14)$$

Besides the line capacity C_f of these lines (which is already part of the nodal EMCP, cf. sec. 2.1.1), RAMs also reflect the difference in reference flows on the corresponding line ($\Delta F_f^{\text{ref,(e)}}$), a final adjustment value (FAV / F_f^{adj}) and a so-called flow reliability margin (FRM / M_f). Neglecting long-term nominations, the difference in reference flows $\Delta F_f^{\text{ref,(e)}}$ is the power flow at expected market outcome reduced by the flow that the zonal power flow approximation implies for the same expected market outcomes (cf. Amprion et al. 2014).

$$\Delta F_f^{\text{ref,(e)}} = \sum_{i \in I} a_{f,i} q_i^{(e)} - \sum_{z \in Z} \sum_{i \in I_z} \tilde{a}_{f,z} q_i^{(e)} \quad (15)$$

Here, the superscript (e) indicates that $q_i^{(e)}$ is an expected quantity, i.e., it is determined in accordance with the expectations at the D-2 stage (cf. sec. 2.2.1).¹⁴ The FAV is a term that can be positive or negative. According to Amprion et al. (2014), a negative FAV can be assigned if complex remedial actions (not being accounted for in the FBMC parameters) can increase capacity margins. Positive FAVs reduce these margins, which can be the case for security reasons. FRMs

¹⁴We distinguish quantities that are expected ((e)) and those which are predetermined according to heuristic procedures ((p)).

take into account the inherent uncertainties of the zonal FBMC process (external exchanges, approximations of the FBMC procedures and differences between forecast and realized programs Amprion et al. (2014)).

Selection of critical branches: Apart from cross-border branches, internal branches can also form part of the set \mathcal{F} . That is, all lines that are marked as "critical" are incorporated to the set \mathcal{F} and, thus, considered in the EMCP.

In general, the so-called 5 %-rule determines which lines are regarded as critical. That is, when the minimum value of the subtraction of two zonal PTDFs (resulting in a zone-to-zone PTDF) of two participating price zones exceeds 5 %. However, also due to the TSOs expertise, lines may be added or removed from the set \mathcal{F} .

The RAMs are calculated according to eq. (13) and (14). However, to avoid convergence issues we limit the RAM to zero, such that $R_f^{nsfd} \leq 0 \leq R_f^{sfd}$.

Having introduced all FBMC parameters, the following section will focus on their related weaknesses, as introduced in sec. 1.

2.3. Modelling the features and proposed adjustments of FBMC

In this section, we describe the key modelling elements to address four research questions (cf. sec. 1). Note that we use the same price zone configuration throughout the complete paper, which corresponds to the current configuration in extended CWE.¹⁵ This includes the analyses performed with regard to imperfect/perfect price zones, for which we rather artificially eliminate existing internal grid bottlenecks instead of adjusting price zone configurations. (cf. sec. 2.3.3).

2.3.1. Use of heuristics

In the introduction, we have highlighted that various options for GSK calculation exist. Table 1 gives an overview over different methods. All presented methods can be classified as heuristic techniques as opposed to forecast-based methods. Thus, we assess the effects of using different GSK methods by executing the mathematical operations from table 1 and undertaking the model sequence in fig. 4. In particular, we investigate the *by capacity*, *by NEX* and *by N* approach.

¹⁵This comprises all countries where flow-based market coupling is currently in effect – namely Germany, Austria, the Netherlands, Belgium, France – and additionally Switzerland. Even though in practice Switzerland does not participate in FBMC, in our model we assume FBMC for all modeled countries.

2.3.2. Process-induced uncertainty

The base case, as introduced in sec. 2.2.2, is usually based on historical data enhanced by the expertise of TSOs. This naturally entails forecast errors. The FBMC parameters that are probably influenced most by forecast errors are the RAMs. Their calculation requires forecasts for the calculation of the term $\Delta F_f^{\text{ref},(e)}$, which involves the expected nodal net exports $q_i^{(e)}$. Main drivers of uncertainties in $q_i^{(e)}$ are the infeed from vRES, load variations and unexpected power plant outages. Thus, if realized net exports deviate from their expected values, this entails inadequacies in LFCs. In addition, forecasting procedures of these values, making use of historical data, may also be a source of uncertainty.

Other values that are subject to inadequacies are the zonal line load sensitivities (i.e., $\tilde{a}_{f,z}$). GSKs can be expected to be one major source of inadequacy. As the considered GSK determination methods are rather heuristic-based than forecast based procedures, we assess forecast errors and GSK procedures separately.

To show the effects of process-induced uncertainties, we introduce forecast errors in the base case calculation.¹⁶ In particular, we use imperfect onshore and offshore wind forecasts for elaborating the estimate of the state of the power system (cf. fig. 4). We approximate the error in wind forecasting by using actual forecast errors published on the Entso-E transparency platform (Entso-E 2018a). We calculate the errors relative to the installed capacity per country and apply the relative errors to each node according to the node's installed wind capacity. The absolute error is limited by the installed capacity at each node, so that forecast wind generation at each node cannot exceed the installed capacity nor drop below zero.

The forecast errors affect the calculation of the flow-based parameters twofold:

1. The calculation of GSKs using the *by NEX* method is affected, because this method relies on the nodal net positions and these net positions depend on the vertical load at each node. The nodal vertical load is affected at each node where wind forecast errors are present. The other GSK methods are not affected, as they are static and therefore do not change with different base cases.
2. RAMs can be affected as well, as the calculation of $\Delta F_f^{\text{ref},(e)}$ depends on the nodal net positions (cf. eq. (15)). However, in the case of the *by NEX* GSK method, RAMs will not be affected, as $\Delta F_f^{\text{ref},(e)}$ is always zero when using the *by NEX* method.

This means that, depending on the GSK method, either RAMs or GSKs will be affected by the uncertainty, but never both.

¹⁶The forecast errors are added to the nodal EMCP as well as the first zonal EMCP, which acts as the base case for the subsequent zonal clearing.

2.3.3. Imperfect price zones

The above sensitivities can be calculated no matter if intra-zonal bottlenecks are present or not. In the first sequence of numerical assessments (cf. sec. 3.1.1 to 3.1.2), we choose to analyze FBMC in a setting without intra-zonal bottlenecks - each price zone then corresponds to a "copperplate". This is simply done by setting thermal capacities of intra-zonal lines to a sufficiently large value. Then, only constraints of cross-border lines can become binding. As discussed in sec. 1, this is far from reality. However, it provides insights into the performance and levers of FBMC in an ideal setting. In contrast to this ideal setting, we also analyze a realistic setting in which all transmission lines are modeled with their thermal capacities expected for the year 2020. In terms of defining the set of CBs, we apply the 5% rule described in sec. 2.2.2. This allows us to evaluate the effect of intra-zonal bottlenecks both on the overall performance of FBMC and on the leverage of the different FBMC varieties on the other hand. Therefore, we recalculate all of the previously introduced sensitivities with the new (realistic) grid setting.

2.3.4. Adjustments to the capacity allocation process

The fourth sensitivity picks up the aspect of internal congestions and, thus, is also applied to the realistic grid setting. The descriptions in sec. 2.2.2 imply that the determination of FAVs and FRMs depends on the expertise of individual TSOs. Moreover, sec. 1 has highlighted that capacities adjustments of both intra-zonal and inter-zonal lines can be used to either foster trade between market participants (increase RAMs) or decrease RD (decrease RAMs). Thus, we assess the four following sensitivities to evaluate the effects of debated capacity adjustments (cf. ACER 2017; Amprion 2017; CREG 2017):

1. As a slight variation of the previous sensitivity, we reduce the RAMs of the 10 most overloaded cross-border lines by 25% of the thermal line capacities. This case is labeled "individual contingency margins (cross-border)".
2. To simulate the effect of reducing the RAMs on critical branches to decrease RD, we reduce the RAMs of the 10 most overloaded transmission lines by 25% of the thermal line capacities. We label that case "individual contingency margins", since it includes a discretionary choice of RAM modifications.
3. In line with the proposal of ACER (2018), we exclude all intra-zonal lines from the set of critical branches \mathcal{F} (cf. eq. 6). Yet, line capacities remain unchanged from their realistic values and these lines are therefore relevant in the nodal EMCP and in the RD stage of the FBMC process.

4. To model the proposal of the European Commission to guarantee a minimum size of of RAMs (cf. EC 2017), we assess a sensitivity that ensures at least 75 % free capacity on all critical branches. This sensitivity can formally be described as follows:

$$R_f^{\text{nsfd}} = \min(-0.75C_f, -C_f - \Delta F_f^{\text{ref,(e)}} + F_f^{\text{adj}} + M_f) = -C_f - \Delta F_f^{\text{ref,(e)}} + F_f^{\text{adj}} + M_f - F_f^{\text{nsfd},75} \quad (16)$$

$$R_f^{\text{sd}} = \max(0.75C_f, C_f - \Delta F_f^{\text{ref,(e)}} - F_f^{\text{adj}} - M_f) = C_f - \Delta F_f^{\text{ref,(e)}} - F_f^{\text{adj}} - M_f + F_f^{\text{sd},75} \quad (17)$$

$F_f^{\text{nsfd},75}$ and $F_f^{\text{sd},75}$ take positive values if the RAM calculations in eq. (13) and (14) respectively lead to values below 75 % of the thermal capacity and 0 otherwise.

5. Finally, we assess the combination of sensitivities 3 and 4.

The results of these investigations are presented in sec. 3.2.4.

2.4. Evaluation methodology

To evaluate and compare results of all sensitivities we apply both economic and statistical indicators.

2.4.1. Economic indicators

As stated in the introduction, a comprehensive consideration of both market and redispatch costs is indispensable. A more constrained FBMC parametrization might cause increasing market clearing costs while costs for redispatch might decrease. Only the sum over both costs gives an indication regarding overall performance of different FBMC configurations. Thus, we always present both the overall system costs and the subdivision in market clearing and redispatching costs. To assess the results, we use several benchmarks:

- The *nodal solution* is used as the first-best benchmark. Known to yield the highest welfare which can theoretically be attained, the overall cost difference between FBMC and the nodal solution can be seen as inefficiency of FBMC (in combination with the investigated price zone configuration).
- The so-called *unlimited trade* scenario is characterized by the nonconsideration of LFCs for the zonal EMCP (i.e., setting \mathcal{F} to $\{\}$ in eq. 6). In other words, congestion is not managed at all. This scenario serves as lower benchmark in terms of welfare. In combination with the nodal solution, this provides a range in which the performance of FBMC can be assessed on a relative scale. 0 % efficiency corresponds to the solution of the unlimited trade scenario, 100 % efficiency is per definition equivalent to the nodal solution..

- The *reference* case is used purely for illustration of results, especially deviations in RD quantities and overall system costs. We arbitrarily choose the setting which uses the *by Capacity* GSK method, is based on perfect foresight and uses the 5 % threshold as selection criterion for identifying critical branches. Having said that, this rule is only relevant in the realistic grid setting. In the *copperplate* setting, no intra-zonal lines become critical. As the realistic setting and the *copperplate* setting correspond to two different states of grid expansion, each setting has its own reference case with distinct overall costs. In order to assess the relevance of the observed differences between cases, we use statistical tests (cf. sec. 2.4.2).

Aside of costs (which are reported in sec. 3) we also analyse redispatch quantities. Details on these results are given in appendix B to improve readability.

2.4.2. Statistical indicators

When observing differences (e.g. in annual market clearing costs, RD costs and amounts) between different cases, the question arises whether these are significant or not. This can be tested using statistical methods - if we interpret the 8760 hourly simulation results as outcomes of a stochastic multivariate process. In fact, input time series of the optimization problem like demand and vRES infeed can be viewed as auto-correlated time-series with time-varying mean and variance. And the optimization results are transforms ("derivatives" in finance language) of these data and hence stochastic processes themselves. The same holds for the differences between results obtained under different settings. Hence we can test for statistical significance using Newey-West adjusted standard errors to account for the autocorrelation and heteroscedasticity present in time-series data.¹⁷ An overview of the corresponding results can be found in fig. 9 and fig. 10 in appendix section C.

¹⁷Lag is set by rounding up $L = T^{\frac{1}{4}}$ to the nearest integer, with T being the sample size (8760 for a full year with no non-converging hours) (see Greene (2012, p. 960)).

3. Numerical assessments for CWE

The subsequent sections present the numerical assessments. As indicated in sec. 2.3.3, we consider two different grid scenarios. We start with an idealized setting where we assume national copperplates by setting line capacities of intra-zonal lines to a sufficiently high value (cf. sec. 3.1). Subsequently, we consider a realistic grid scenario by reducing thermal capacities to their actual (realistic) values (cf. sec 3.2). For each of the scenarios, we investigate the identified research questions and features of FBMC.

For both grid settings, we start by giving a general overview of FBMC performance (cf. sec. 3.1.1 and sec. 3.2.1), investigate the use of heuristics (cf. sec. 3.1.2 and sec. 3.2.2), process induced uncertainties (cf. 3.1.3 and 3.2.3) and for the realistic grid scenario the adjustments to the capacity allocations (cf. sec. 3.2.4)

3.1. Idealized price zones

3.1.1. Overall performance of FBMC

To classify FBMC's performance, we contrast it to two extremes. On one hand, we compare FBMC system costs to those of a nodal pricing set-up as the theoretical optimum. On the other hand, we compare results to the "unlimited trade" scenario, introduced in sec. 2.4.1. This market clearing configuration assumes no constraints for trade on the day-ahead market (i.e., dropping eq. 6) and completely relies on redispatch for the relief of congestions. As mentioned above, for all assessments in this section we presume the idealized grid setting without intra-zonal bottlenecks.

Fig. 5 provides a depiction of the system costs for nodal pricing, FBMC and unlimited trade. These system costs are composed of market clearing costs, being the operational costs at the D-1 stage, and redispatching costs. While redispatching leads to additional costs for the unlimited trade and FBMC scenarios, nodal pricing does not incur additional redispatching costs, as the grid is completely represented in the market clearing.

On the one hand, market clearing costs are lowest for the unlimited trade scenario because market coupling is unconstrained. Yet there is a trade-off with redispatching costs, which amount to over 1 billion Euros. On the other hand, nodal clearing costs exceed the clearing costs in the unlimited case by about 200 million Euros, but the clearing is completely efficient, as no redispatching is needed. The total cost difference between unlimited trade and nodal pricing amounts to 825 million Euros. Clearing costs for FBMC are higher than costs for nodal pricing, while redispatching costs are quite low (38 million Euros) compared to unlimited trade.

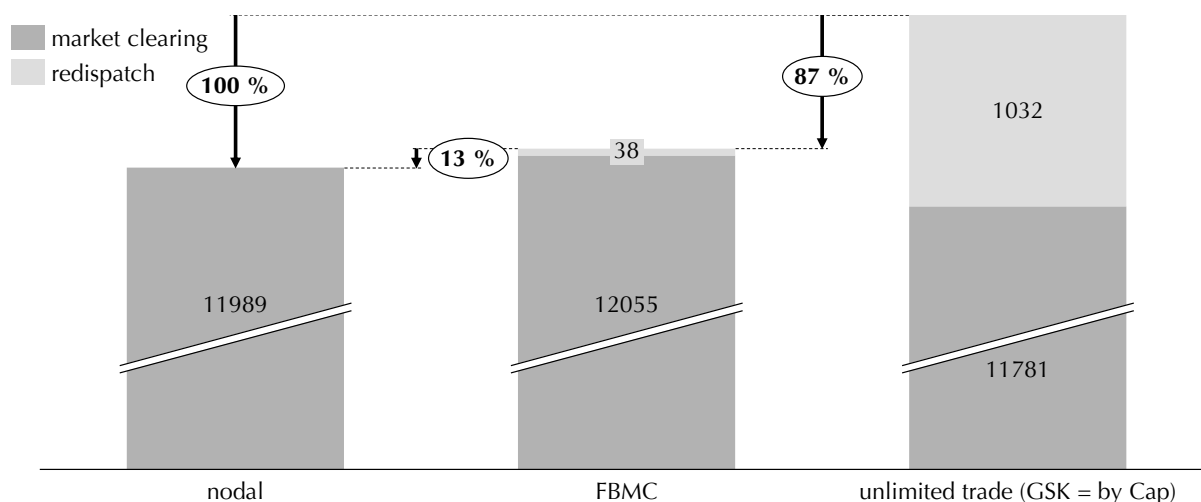


Figure 5: Overall evaluation. Costs in million EUR.

The difference in redispatching costs is related to RD quantities. A comparison of RD quantities at the nodal level is given in fig. 6. Therein, up- and downward pointing triangles indicate positive and negative RD of power plants respectively, while their sizes correspond the sum of yearly quantities.

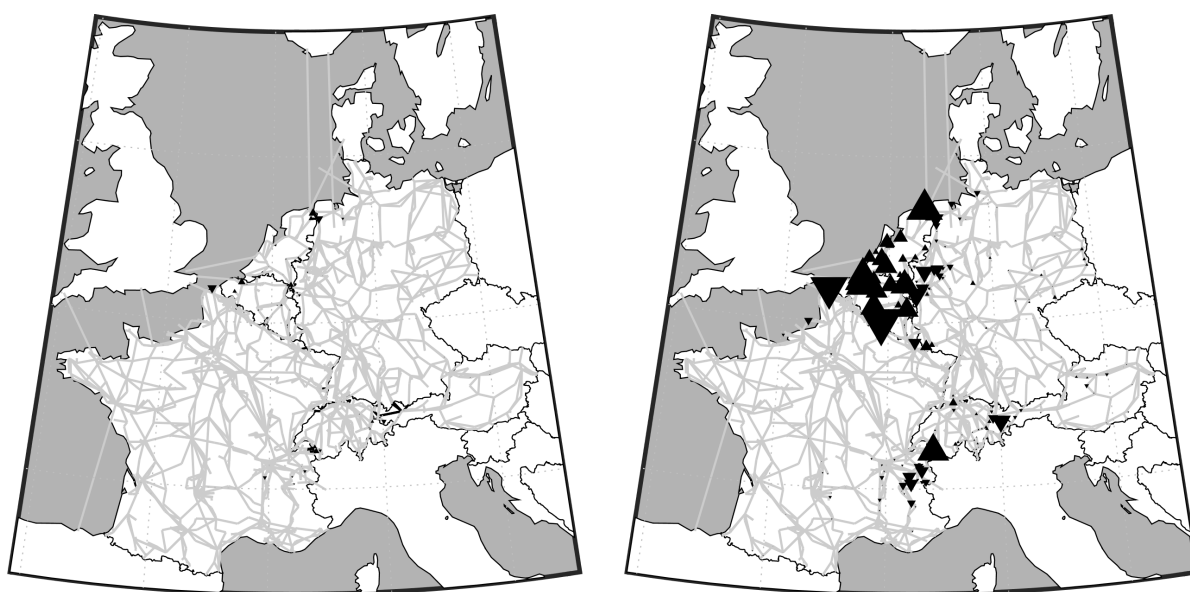


Figure 6: Sum of redispatch per node. Left: FBMC with *by capacity* GSKs. Right: Unlimited trade. Critical branches in black.

The necessity for RD is much higher in the unlimited trade scenario, which results in the aforementioned significantly higher RD costs. The total cost difference between nodal pricing and FBMC is 105 million Euros, which means that FBMC saves 720 million Euros compared to unlimited trade.

Treating the 825 million Euros that nodal pricing saves compared to the unlimited trade scenario as the benchmark, the savings of 720 million Euros represent 87 % of what is theoretically achievable.

3.1.2. Use of heuristics

Table 2 shows the results for all three GSK methods with perfect foresight as well as process-induced uncertainty. The results from the overall evaluation in sec. 3.1.1 are provided as a reference. Besides the total costs for the market clearings and for redispatch, the table also shows the cost difference between the summed costs of the zonal clearing with redispatch and the nodal clearing. To facilitate comparisons between the different scenarios, one column always shows the total cost difference to the reference scenario (with *by capacity* GSKs).

Table 2: Numerical results. Costs in million EUR.

no.	description	total cost			cost difference clearing + RD		
		clearing	RD	total	vs. nodal	vs. ref	vs. perfect foresight
1	nodal	11 989	0	11 989	0	-	-
2	unlimited trade	11 781	1032	12 813	825	719.6	-
<i>use of heuristics (with perfect foresight):</i>							
3	by capacity (= ref)	12 055	38	12 094	105	0.0	-
4	by NEX	12 018	196	12 214	225	120.4	-
5	by N	12 065	45	12 110	121	16.3	-
<i>process-induced uncertainty:</i>							
6	by capacity	12 057	42	12 098	110	4.7	4.7
7	by NEX	12 024	193	12 217	229	123.7	3.4
8	by N	12 065	49	12 115	126	20.9	4.6

Regarding overall costs, there are significant differences between the GSK methods. The *by N* method gets within 16 million Euros of the reference case. However, the *by NEX* method produces lower clearing costs than both other GSK methods, but redispatching costs are higher by over 150 million Euros, resulting in a 120 million Euros difference in total costs compared to the reference. Having a closer look into the implications of the *by NEX* method, gives an explanation: The GSKs are calculated as the share of nodal exports from zonal exports. This means that non-zero GSKs are assigned even to nodes without generation units participating in the market clearing. Additionally, positive generation in zones with negative exports leads to negative GSKs being assigned to the nodes of these generation units. Consequently, these generation units contribute to FBMC-approximated line loadings in the opposite direction compared to the physical reality. Both effects distort the results, which entails much higher overall costs.

3.1.3. Process induced uncertainties

In contrast to the variation of GSKs, the introduction of forecast errors as introduced in sec. 2.3.2 shows less significant results (cf. tab. 2, lower part). Costs increase by 3.4 million Euros to 4.7 million Euros depending on the considered GSK. The least increase in costs is observed for the *by NEX* method, however, its overall costs are still significantly higher than costs of the other sensitivities.

3.2. Imperfect price zones

So far, we have investigated all scenarios assuming national copperplates. However, in order to assess the influence of imperfect price zones, i.e., zones with (congested) internal branches, we now consider the actual thermal capacities of intra-zonal branches.

3.2.1. General view on FBMC performance

We start by recalculating our initial assessment of sec. 3.1.1, consisting of the nodal set-up, the reference case using FBMC with *by capacity* GSKs and the unlimited trade scenario with the new grid setting. Fig. 7 and fig. 8 show the results.

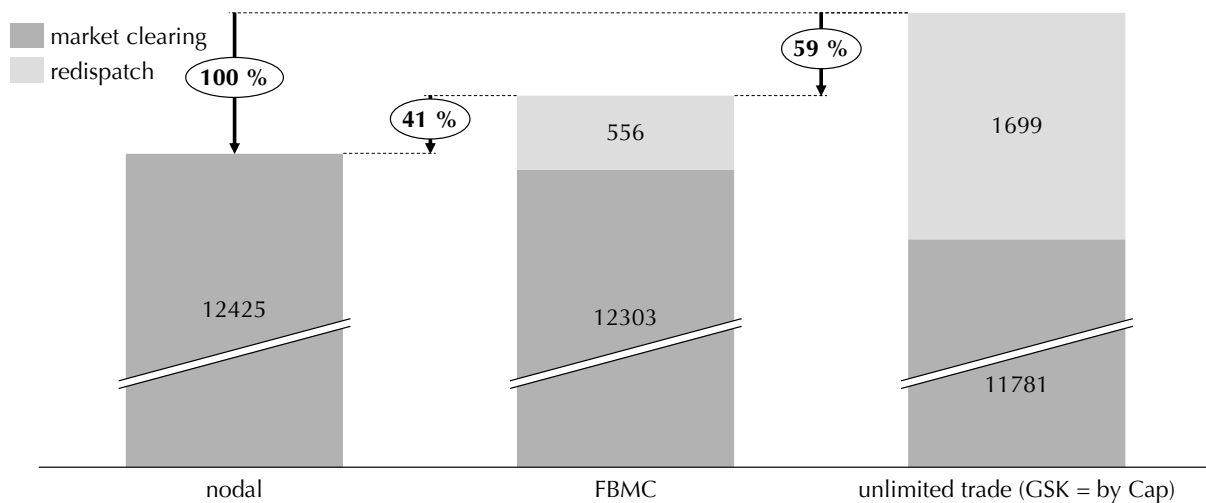


Figure 7: Overall evaluation with imperfect bidding zones. Costs in million EUR.

As expected, system costs in both the nodal pricing as well as the unlimited trade scenarios increase because of the additional congestion. However, while nodal costs increase by 436 million Euros, costs of the unlimited trade scenario increase by 667 million Euros – a difference of 231 million Euros. Because the market clearing results in the unlimited trade scenario remain unchanged, this increase is directly related to higher RD costs. In the reference FBMC approach, costs increase by 766 million Euros.

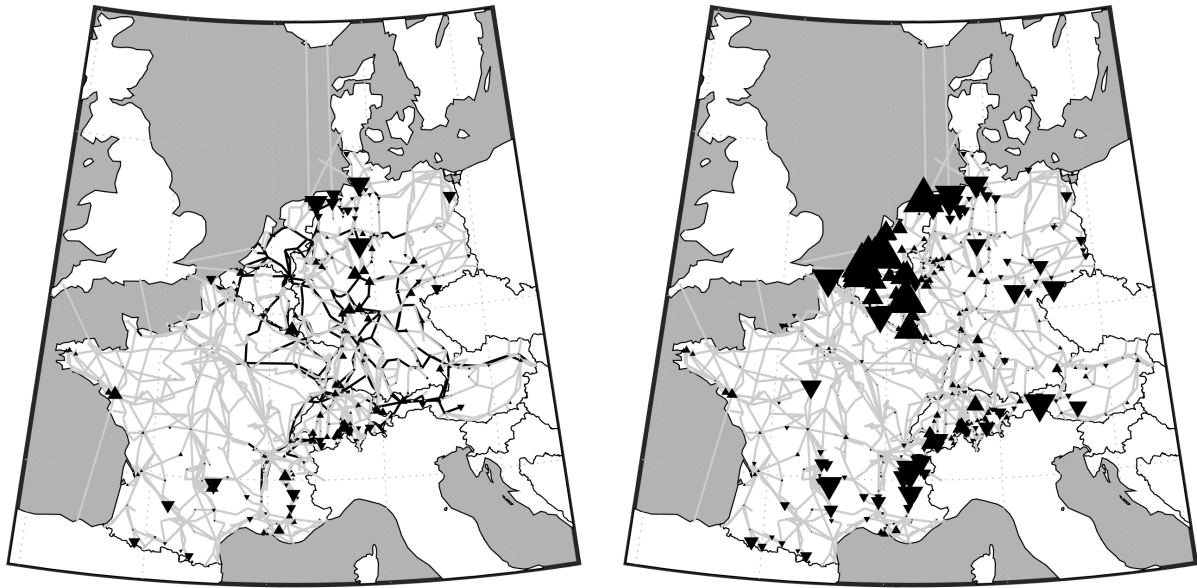


Figure 8: Sum of redispatch per node with realistic thermal capacities. Left: FBMC with *by capacity* GSKs. Right: Unlimited trade. Critical branches in black.

The larger increases in total costs in the FBMC approach compared to both the nodal as well as the unlimited trade scenario mean that the efficiency of FBMC decreases. Nodal pricing achieves savings of 1055 million Euros compared to unlimited trade, whereas FBMC achieves 620 million Euros. Consequently, while FBMC, applied with price zones without internal congestions achieved an efficiency of 87 % in reference to the cost difference between nodal and unlimited trade (cf. 3.1.1), the value drops to 59 % for the investigated internally congested grid.

3.2.2. Use of heuristics

The results shown above point to a large negative impact that imperfect price zones have on the efficiency of FBMC. Additional impacts of imperfect price zones become apparent in the further results. As tab. 3 shows, cost differences between the different GSK methods decrease significantly. While the *by NEX* constituted by far the most expensive GSK method in section 3.1.2 with an increase of 120 million Euros in reference to *by capacity*, the cost increase is reduced to 2 million Euros for the *by NEX* method, which is statistically nonsignificant. The cost increase of the *by N* method compared to the reference stays almost the same in absolute terms (16 million Euros), but much higher total costs than without internal congestions imply lower relative differences between the methods.

3.2.3. Process induced uncertainties

In contrast, the effect of forecast errors remains rather small. Costs increase by between 1.2 million Euros for the *by NEX* method and 3.1 million Euros for the *by capacity* method. The cost increases

Table 3: Numerical results with imperfect bidding zones (reference grid expansion). Costs in million EUR.

no.	description	total cost			cost difference clearing + RD		
		clearing	RD	total	vs. nodal	vs. ref	vs. perfect foresight
11	nodal	12 425	0	12 425	0	-	-
12	unlimited trade	11 781	1 699	13 480	1 055	620.4	-
<i>use of heuristics (with perfect foresight):</i>							
13	by capacity (= ref)	12 303	556	12 859	435	0.0	-
14	by NEX	12 178	684	12 862	437	2.4	-
15	by N	12 316	560	12 875	450	15.8	-
<i>process-induced uncertainty:</i>							
16	by capacity	12 301	561	12 862	438	3.1	3.1
17	by NEX	12 181	683	12 865	440	5.2	2.8
18	by N	12 312	565	12 876	452	17.0	1.2

of the *by capacity* and *by NEX* methods are found to be statistically significant (based on the test procedure described in sec. 2.4.2), while the increase of the *by N* method does not (all compared to the same GSKs with perfect foresight).

3.2.4. Adjustments to the capacity allocation process

Table 4 shows the results for the sensitivity regarding the adjustment of the capacity allocation process (cf. sec. 2.3.4). As in section 3.2, we use the grid model with internal congestions.

Table 4: Numerical results with adjustments to the allocation process and imperfect bidding zones (reference grid expansion). Costs in million EUR.

no.	description	total cost			RD ↑ (TWh)
		clearing	RD	vs. ref	
13	by capacity (= ref)	12 303	556	0.0	9.50
<i>adjustments to the capacity allocation process (all with GSK = by capacity):</i>					
19	individual contingency margins	12 318	550	8.2	9.29
20	individual contingency margins (cross-border)	12 442	520	103.1	8.77
21	no internal CBs	12 057	839	36.2	15.50
22	minimum RAM 75 %	12 058	818	16.5	14.34
23	no internal CBs + minimum RAM 75 %	12 034	900	74.9	17.25

In our calculations, the top 10 overloaded lines overall are all intra-zonal lines. It follows that there is no overlap between the two sets of lines considered for reduction of RAMs described in sec. 2.3.4 – the other being top ten overloaded cross-border lines. Placing individual contingency margins and thus reducing RAMs on the top 10 overall overloaded lines (case 19) and the top 10 overloaded cross-border lines (case 20) increases costs in both cases, but by substantially different amounts. In case 19, costs rise by 8 million Euros, while reducing RAMs on the top 10 overloaded

cross-border lines (case 20) increases costs by 103 million Euros. Somewhat reduced redispatch volumes (-0.73 TWh per direction compared to reference) and therefore reduced redispatching costs are traded for much higher clearing costs.

Omitting internal CBs (case 21), forcing RAMs to at least 75 % of maximum thermal capacity (case 22) and the combination of both (case 23) lead to higher costs as well. However, in contrast to case 19 and case 20 the increase is due to higher costs for redispatching, which cannot be offset by decreasing market clearing costs. In particular, omitting internal CBs (case 21) lowers the zonal clearing costs but increases redispatching costs by a much larger amount, leading to an increase in total costs of 36 million Euros. Even though internal constraints are not adequately represented in a zonal setting, completely omitting them to facilitate cross-zonal trade leads to higher costs overall. For case 22, the observed increase of 16 million Euros compared to the reference case is not as big. For both cases, lower clearing costs are bought by an increase in upward-redispatching volumes of 4.85 TWh and 6 TWh, respectively. The effect is strengthened when both measures are applied at the same time (case 23), where costs increase to 74.9 million Euros while RD quantities increase to 17.25 TWh.

4. Discussion and conclusion

The paper at hand presents an in-depth analysis of Flow-Based Market Coupling – one of the cornerstones of the European target model for electricity market design. Subsequently, we summarize the key findings of our analyses and link them to current (political) discussions and publications. Therefore, we take up the FBMC features and possible adjustments subsequently: (i) use of heuristics, (ii), process-induced uncertainties, (iii) imperfect price zones and (iv) adjustments to the capacity allocation process. The guiding questions of this paper are recapped as follows:

1. How dependent is the efficiency of FBMC on the chosen GSK method?
2. To what degree are FBMC results susceptible to forecast errors?
3. How do imperfect bidding zones, i.e., zones with internal congestions, impact the performance of FBMC?
4. What are the impacts of adjustments to the capacity allocation process? Are capacity adjustments an expedient means to decrease redispatch or increase cross-border trade?

Besides allowing us to draw conclusions on these specific questions, this paper has also placed the performance of FBMC in context.

Our analyses thereby reveal that, given a suitable (or idealized) setting for FBMC, the overall performance of the FBMC approach comes close to that of the theoretical first-best solution (i.e., the nodal pricing solution). Using the *unlimited trade* setting as second reference, FBMC realizes around 87 % of the welfare gains that are possibly achievable through market coupling. In absolute terms, inefficiencies in terms of welfare of around 100 million Euros remain when using FBMC. In a broader sense, this might be considered the cost of maintaining zonally organized electricity markets with the resulting benefits (such as reduced vulnerability to market power, nonexistence of redistributive effects due to heterogenous prices within countries, highly liquid markets and, in case of stable zones, no transitional costs).

This picture changes substantially once conditions are not ideal. In a realistic setting, where intra-zonal bottlenecks are commonplace, FBMC only attains about 59 % of the theoretically possible welfare gains.

Contrasting both situations we conclude: FBMC generally has the capability of performing reasonably well. The problems of FBMC arise from intra-zonal bottlenecks. As shown by Felten et al. (2019), FBMC is ineffective in managing intra-zonal congestion, because the main cause of this congestion – intra-zonal trade – is not controlled by the market clearing process. Solution approaches to this problem include the acceleration of the grid expansion process or the enhancement of price zone configurations. Either one would help to improve efficiency of FBMC.

With respect to the specific questions recapped above, we find that results show significant differences for the different investigated GSK methods when assuming national copperplates. In this

setting, the overall cost difference between the *by Capacity* and *by NEX* GSK method amounts to more than 120 million Euros. Moreover, the welfare changes due to the use of different GSK methods are all statistically significant.

However, when considering imperfect price zones with intra-zonal bottlenecks, the impacts of different GSK methods become very small. Even the quite naive *by NEX* method achieves results close to the reference GSK method. In several cases, the cost differences are not even statistically significant. While this result may surprise at first sight, it is in line with results presented in Dierstein (2017) and Finck et al. (2018). Again, the explanation lies in the existence of intra-zonal bottlenecks. The ineffectiveness in managing intra-zonal congestion is more dominant than the change in GSK methods. Similar to our realistic setting, Dierstein (2017) and Finck et al. (2018) investigate price zones with a relevant number of intra-zonal bottlenecks. And Dierstein (2017) shows that the difference of the *by Capacity* and *by N* method is comparably small. The six different GSKs of Finck et al. (2018) do not show major effects on overall generation shifts either. Mainly with regard to generation shifts in Czech Republic (where intra-zonal bottlenecks may not be as dominant), Finck et al. (2018) observes bigger generation shifts.

The main take-away from these analyses is that the improvement of GSK procedures is likely to become relevant in the future or for single price zones with little intra-zonal bottlenecks. Once grid expansion proceeds or price zones are reconfigured, GSK choices will have relevant leverage on overall welfare. For the current situation, however, GSK changes hardly make a difference.

The second question concerns the role of forecast errors. We show that these errors do not have a major effect on welfare. Cost increases resulting from forecast errors only amount to 3 to 5 million Euros. Moreover, independent from the existence of intra-zonal bottlenecks, the importance of forecast errors remains very small. Our interpretation of these results is positive: FBMC is quite robust against forecast errors – at least under all investigated settings.

The answer to the third research question is already implicit in the above conclusions. Imperfect price zones (i.e., intra-zonal bottlenecks) have a major influence on the overall performance of FBMC and on the leverage of GSK choices. While welfare losses of FBMC compared to the nodal solution amount to roughly 100 million Euros in the ideal setting, the drop in FBMC efficiency in the realistic price zone setting lets welfare losses increase drastically – namely to around 440 million Euros. Such a degree of inefficiency is likely to outweigh the benefits of zonal pricing.

The last research question is particularly relevant in case of imperfect price zones. Starting with the national *copperplate* results, redispatch amounts and costs are fairly low. Redispatch quantities in the *copperplate* setting are below 1 TWh; redispatch costs are below 50 million Euros. Such a situation would certainly not impel TSOs to introduce *individual contingency margins* on lines. In a realistic setting, redispatch quantities rise to around 10 TWh. Reducing the RAMs may be seen as one means to decrease redispatch. As a matter of fact, our results show that contingency margins on a small set of cross-border lines (i.e., on 10 lines) can reduce redispatch amounts by almost

8 %. This redispatch reduction comes at the expense of overall welfare, yielding additional system costs (market clearing and redispatch) of above 100 million Euros. In turn, contingency margins on the 10 most congested intra-zonal lines have a much lower effect (redispatch decrease: approx. 2 %, system cost increase: approx. 8 million Euros). Again, this is in line with the explanations in Felten et al. (2019) on the ineffectiveness of congestion management of intra-zonal lines.

In contrast, regulatory measures that increase RAMs or exclude intra-zonal line constraints from the market clearing problem have a major impact – especially on redispatch amounts. In these scenarios, our results show that redispatch quantities increase by 5 to 6 TWh or even 8 TWh when both measures are combined (i.e., + 52 %, 63 % and 82 %, respectively, compared to the reference scenario). These heavy increases would certainly pose an operational challenge to Europe's TSOs. Correspondingly, redispatch costs increase by 262 to 283 million Euros. As electricity trading is fostered by the increase / nonconsideration of RAMs, market clearing costs decrease at the same time (by around 250 million Euros). This is in line with results of the market clearing in similar scenarios reported in Wyrwoll et al. (2018). Notably, redispatch costs are not assessed in Wyrwoll et al. (2018). As demonstrated above, however, redispatch amounts and costs are key to evaluating these regulatory changes. Overall, we observe system cost increases (17 – 36 million Euros). However, these overall cost increases are much more moderate than those resulting from reduced RAMs on cross-border lines. Nevertheless, the proposals made in ACER (2018) and EC (2017) are neither beneficial with respect to welfare nor with regard to redispatch amounts. In terms of redispatch amounts, these proposals may even be quite harmful. Regulators should bear this in mind when considering adjustments to rules of the capacity allocation process

In conclusion, our investigations provide a systematic analysis of the performance and levers of Flow-Based Market Coupling. Most importantly, (i) the relevance of intra-zonal bottlenecks on the performance of FBMC calls for reconfiguration of price zones or accelerated grid expansion, (ii) the regulatory changes proposed in ACER (2018) and EC (2017) carry the risk – or rather high probability – of severe increases of redispatch amounts and costs, and (iii) other debated FBMC features (e.g., GSKs, forecast errors) may not be as important as commonly believed – at least as long as intra-zonal transmission line capacities are scarce.

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Appendix

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A. Assumptions

Throughout the entire paper, we assume effective competition, implying that generators bid at their marginal costs and do not bid strategically. Furthermore, we assume inelastic demand. That is to say that the market clearing process, which has the goal of welfare maximization, can also be expressed as a cost minimization.

In terms of power plant dispatch, we assume that all power plants are available for dispatch and redispatch. Moreover, we neither consider minimum generation, intertemporal constraints (e.g., reservoir filling levels, minimum downtimes / operation times, etc.) nor must-run restrictions (e.g., minimum operation from combined heat and power plants or the like). For hydro power plants having the flexibility of reservoirs, we consider shadow prices in daily resolution, which makes their dispatch rationale comparable to the one of thermal power plants. Neglecting intertemporal constraints entails some inaccuracies. However, it allows us to establish *ceteris paribus* comparisons of the FBMC zonal market design to contrast the zonal solution with the first-best solution (i.e., the solution under a nodal market design). A further assumption is that non-dispatchable renewables-based generation (from solar and wind) and generation of units connected to lower voltage levels are directly considered in the vertical load d_i . Hence, this generation is completely fed into the grid as long as technically possible.¹⁸

In terms of power flow modeling, we use the DC-lossless assumption. Additionally, we do not consider topology changes of the grid. Thus, the power flows can be modelled as set of linear equations using power transfer distribution factors (PTDF / $a_{f,i}$).¹⁹ Grid security considerations are approximated by reducing the thermal capacity of transmission lines to 85 % of their nominal values. In terms of commercial exchanges (cross-zonal transactions), we do not consider long-term nominations. Thus, the entire exchange results from the market clearing (and potential adjustments through redispatch). We simplify the stages of the market clearing in a way that we consider the day-ahead and intraday trading stages as one common step. That is to say, only the effect of foresight deviations for formulating grid constraints is considered. In terms of dispatch optimization (given the predetermined grid constraints), foresight is always assumed to be perfect.

¹⁸Curtailement is only allowed at relatively high penalties. Here we set costs to 100 EUR / MWh to account for compensation of lost subsidies

¹⁹For an explanation of these PTDFs, see sec. 2.1.1.

B. Redispatch indicators

Table 5: Redispatch indicators for all cases.

no	description	annual redispatch				peak hour	
		∅		total		total	
		viol.	constr.	measures		all	measures
		#	#	TWh	TWh	MWh	#
idealized price zones:							
2	unlimited trade	5.1	23.1	25.9	25.9	19 357	61
<i>use of heuristics (with perfect foresight):</i>							
3	by capacity (= ref)	1.0	2.5	0.6	0.6	837	5
4	by NEX	1.9	6.2	3.3	3.3	2779	13
5	by N	1.0	2.4	0.7	0.7	892	8
<i>process-induced uncertainty:</i>							
6	by capacity	1.0	2.6	0.7	0.7	886	8
7	by NEX	1.9	6.2	3.3	3.3	2805	13
8	by N	1.0	2.6	0.8	0.8	1091	11
imperfect price zones:							
<i>use of heuristics (with perfect foresight):</i>							
12	unlimited trade	38.6	53.9	41.1	37.0	20 116	72
13	by capacity (= ref)	11.6	20.2	9.5	3.3	11 564	91
14	by NEX	11.8	22.2	11.2	5.5	10 526	135
15	by N	11.5	20.4	10.0	3.4	10 798	92
<i>process-induced uncertainty:</i>							
16	by capacity	11.7	20.4	9.6	3.4	11 715	93
17	by NEX	11.8	22.2	11.2	5.5	10 568	104
18	by N	11.5	20.6	10.0	3.5	10 843	91
<i>adjustments to the capacity allocation process (all with GSK = by capacity):</i>							
19	individual contingency margins	11.3	19.8	9.3	3.2	11 564	91
20	indiv. cont. margins (cross-border)	9.7	18.4	8.8	2.9	11 564	91
21	no internal CBs	16.6	27.6	15.5	8.7	12 263	160
22	minimum RAM 75 %	15.4	25.7	14.3	7.9	11 688	99
23	no internal CBs + min. RAM 75 %	18.5	30.6	17.3	10.6	11 709	97

C. Significance tests

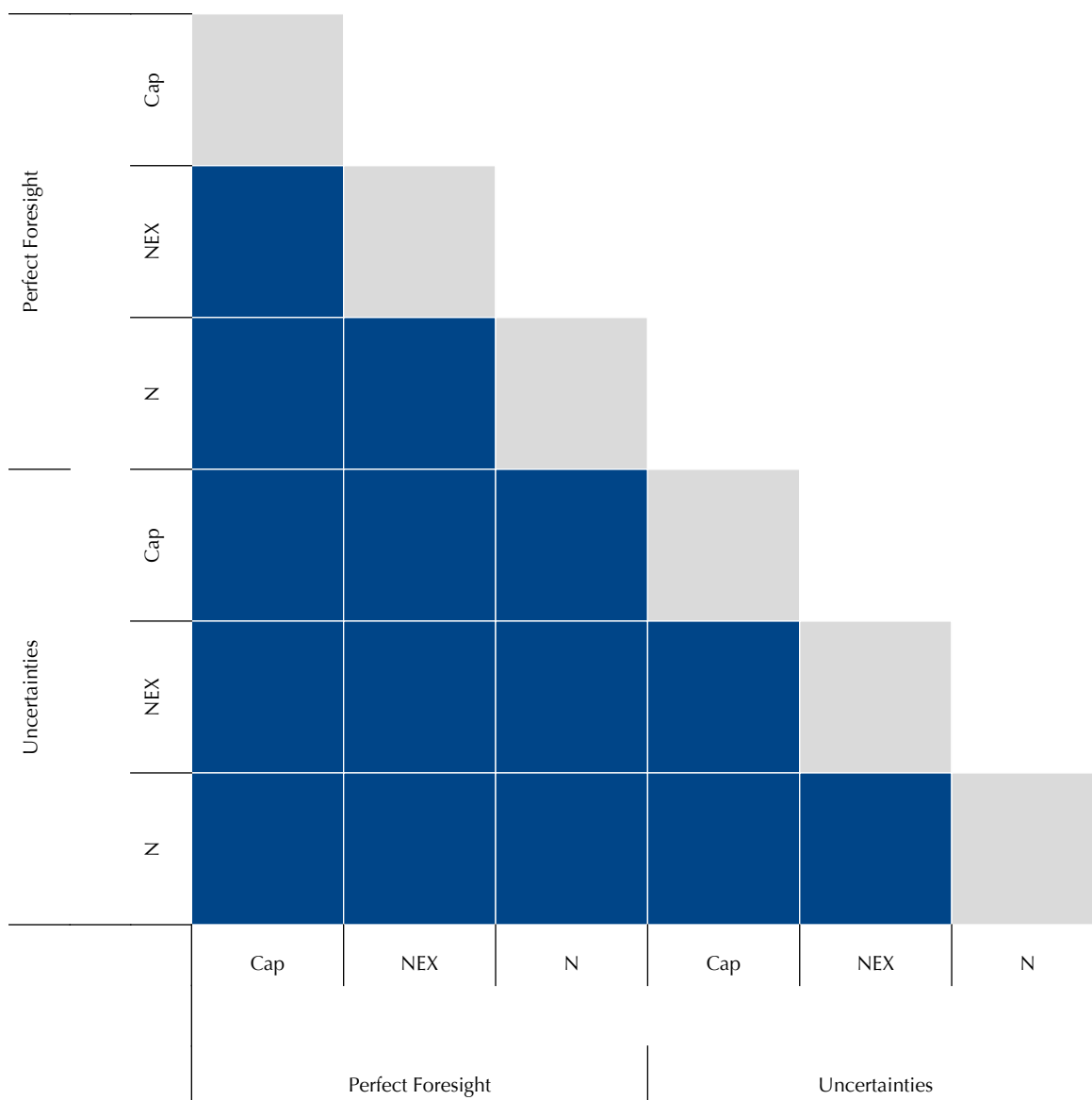


Figure 9: Significant differences between total cost (zonal + redispatch) time series with copper plate assumption using Newey-West adjusted standard errors. Significant differences (at $p = 0.05$) are highlighted in blue.

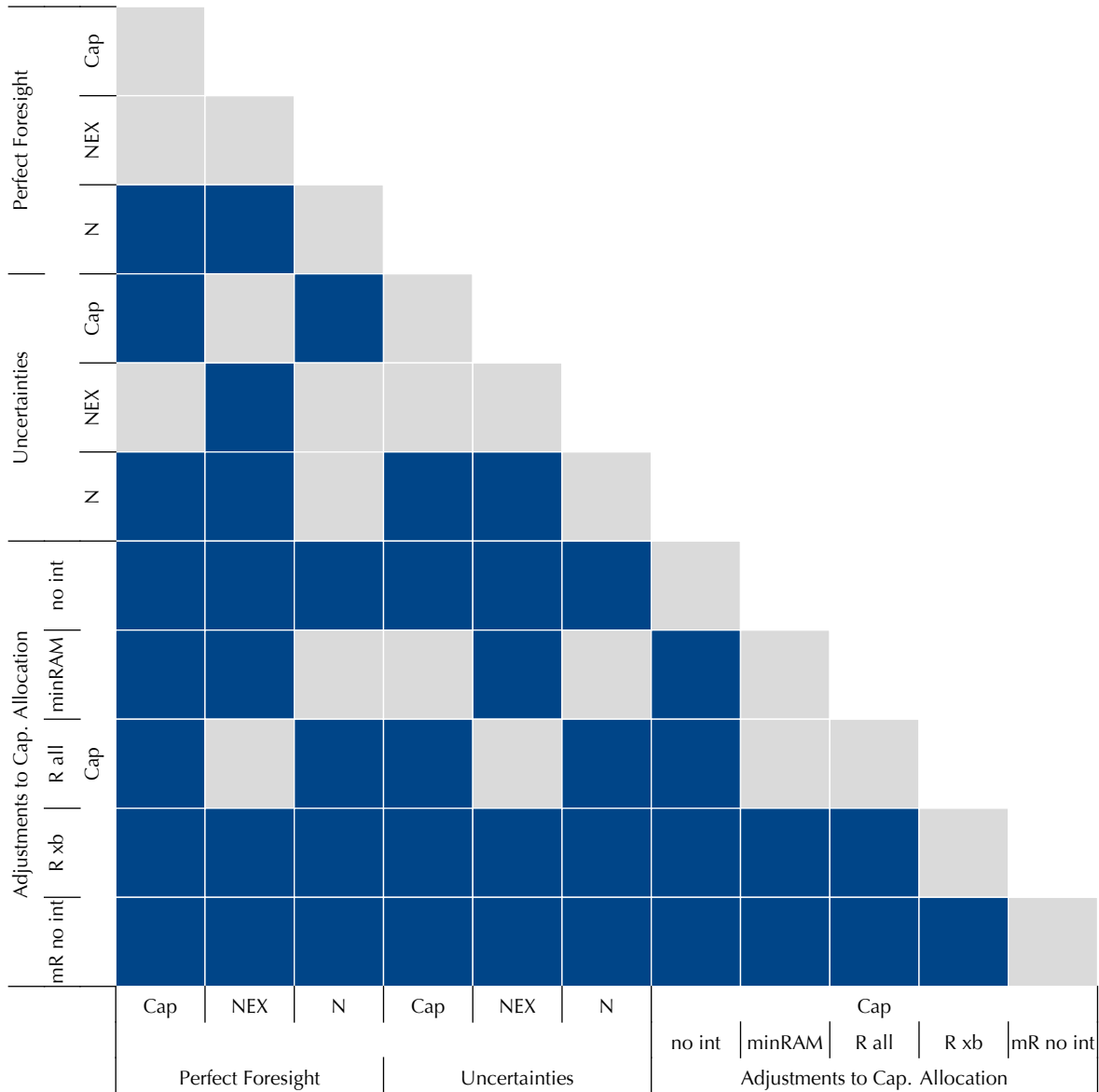


Figure 10: Significant differences between total cost (zonal + redispatch) time series with realistic grid (internal congestions) using Newey-West adjusted standard errors. Significant differences (at $p = 0.05$) are highlighted in blue. Groupings: GSK method, type of adjustment to allocation process. No int: No internal critical branches. R all: Individual contingency margins. R xb: Individual contingency margins (only cross-border). minRAM: minimum RAM of 75 %. mR no int: minRAM + no int.

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