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Analysis of Market Coupling Based on a Combined Network and Market Model

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***Abstract*—In this paper the possible implementation and the efficiency of multilateral market coupling are evaluated. Market coupling is known as the cooperation of power exchanges and other market players in order to utilize the limited capacity of a meshed electricity transmission system in an efficient way. Based on a three-part combined network and market model of the Central Western European region, the congestion management is simulated and possible alternatives in the different steps of the practical execution are compared to each other. The results are rated from an economic and technical point of view in terms of system-wide welfare as well as utilization and security of the congested lines.**

***Index Terms*—congestion management, electricity markets, flow-based market coupling, power transfer distribution factors.**

I. Introduction

THE increasing international exchange of electricity leads to several bottlenecks in the transmission system. The existence of these bottlenecks requires the implementation of congestion management methods to utilize the limited capacity of the transmission system in an efficient way. The efficiency of the adopted method can be described by the system-wide economic welfare. While acting in different markets, the market players require information about the surrounding markets to coordinate their transactions. Any uncertainty, e.g. about the price spread between different market areas or about the costs for the utilization of the bottleneck, leads to inefficiencies of the market result. The congested lines between an area with low prices and another one with high prices are not fully loaded in this case, or the actual load flow is even in the “wrong” direction, with an additional export from a high price area into a low price area.

The European Regulators' Group for electricity and gas (ERGEG) identifies in [1] two targeted congestion management methods for Europe. Compatible methods must be able to accommodate both explicit and implicit auctions. In an explicit auction the applicants have to declare along with their requested capacity amount how much they are willing to pay for this capacity. With implicit auctioning, transmission capacity is managed implicitly by the power exchanges. The market players submit energy bids in the market area where they wish to generate or consume, and the market clearing procedure determines the most efficient amount and direction of physical exchange of electricity between the market areas [2]. As mentioned in [3], explicit auctions are equivalent to implicit auctions, only with incomplete information, because the market participants have to predict the price spread in order to submit their explicit capacity bids.

The administrative cooperation of power exchanges and other involved players, e.g. transmission system operators or regulators, is denoted as market coupling. Hence, market coupling enables the regional markets to trade with each other if it is economically efficient to do so [4].

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II. Combined Network and Market Model

A. Procedure of the modeling

The combined network and market model consists of three main parts. In a first step, the different market areas are simulated without taking the network and possible transits into consideration. Hence, local load is exclusively covered by local generation. This results in local prices as well as demand and supply curves for every market area. In addition, the nodal inputs and outputs are allocated to the network model to perform load flow calculations.

The second main part of the model is calculation of the load flow and identification of potential transits between the market areas and their correlation to the nodal inputs and outputs. The so called power transfer distribution factors (PTDFs) provide a linear mapping of an increased input in one node and the resulting change of the loading of a certain line. This linearization is feasible in the neighborhood of the base case. The resulting sensitivity matrix summarizes the influence between every node and line of the regarded system.

With the information from the wholesale market model and the PTDF matrices, the third part of the model, the simulation of the market coupling, can be carried out. In this part of the model, the optimal imports and exports between the different market areas are identified in order to maximize the system-wide economic welfare. By using the PTDF matrices in the simulation, the limits of the cross-border lines can be taken into account. The results from the market coupling simulation are used again to calculate a load flow. This check provides a hint about the deviation between the results of the market coupling simulation and the full AC load flow calculations due to the linearization of the PTDFs, and due to the temporal resolution of the PTDF calculation. The calculation of sensitivity matrices for every single hour leads to low deviations but requires the identification of a base case also for every hour and increases the uncertainty for the market participants as the available capacity for trading transactions changes every hour.

Figure 1 shows the procedure of the modeling and the exchanged data between the different parts of the model.

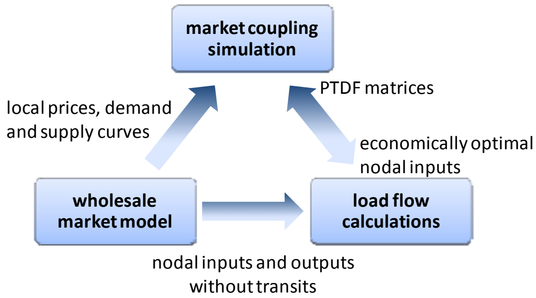

Fig. 1. Flow-chart of the combined model.

In the following sections the three main parts of the combined model are described in detail.

B. *Wholesale market model*

The proposed wholesale market model is a so called fundamental model, as it is mainly based on data of the power plant mix and the load of the regarded market. Furthermore, there are approaches based on time series analysis or oligopoly models which explicitly analyze the interaction between market participants and their bidding strategies.

The common core of fundamental models is the mapping of the demand and supply side of the market. Based on the cost functions of the supplying power plants in every point in time, a market clearing price results for a given load (under the assumption of a totally price-inelastic demand). These models can be classified further into simulating and optimizing models. Simulating models are based on experiences, e.g. operating periods of the power plants, which constitute fixed constraints. In contrast to that, optimizing models consider operating constrains and partial-load characteristics for every single type of power plant. The utilized model in this work is a simulation of the market; optimization might lead to more precise results in some ranges but the computation time amounts to a multiple compared to a simulating model.

The main problem of the simulation is the consideration of restrictions for the different types of power plants, e.g. a nuclear power plant may not be used to cover peak load. In this context also the start-up costs are important and have to be taken into account. If a power plant is operated during short periods, the start-up costs have a significant impact on the marginal costs. To solve this problem, the following steps are implemented.

The load curve of the regarded year is divided into different segments. The first segment, base load 1, is defined as the seasonal minimum of the load and therefore changes only four times a year. The second segment, base load 2, is the minimum of the business days of one week. By definition, the power plants in this segment are started once a week and the resulting start-up costs are distributed to the marginal costs during the time of operation. The third segment is the medium load in which the power plants are started once a day with an average operation time of about 14-16 hours. The remaining difference between the actual load and the medium load segment is covered by peak load power plants. Figure 2 clarifies this definition of the load segments.

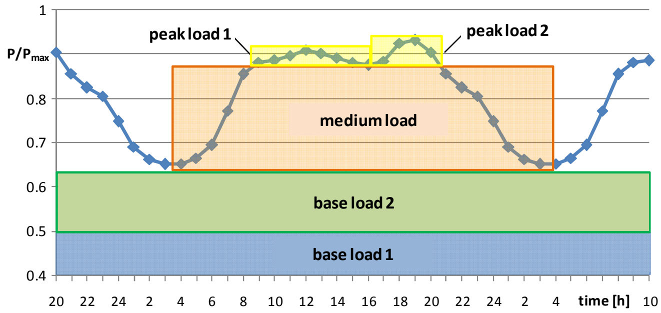

Fig. 2. Segmentation of the load curve.

Due to the allocation of the start-up costs and the consideration of operational restrictions, there exist different merit orders in every segment. Based on these merit orders the load is covered sequentially; the market clearing price is the maximum of the resulting prices in each of the segments which is usually the price in the peak load segment.

To visualize the accuracy of the market model, the results for the German market in 2005 are compared to the appropriate price at the European Energy Exchange (EEX), located in Leipzig, Germany. For the German market, a database of about 400 power plants is utilized; containing fuel type, age, efficiency, and availability. Figure 3 provides the comparison of the daily base prices, i.e. the average of the 24 hourly prices. Obviously, the general level and behavior is met. As the model uses expected values of the availability, fly-ups with prices above 80 €/MWh cannot be reproduced.

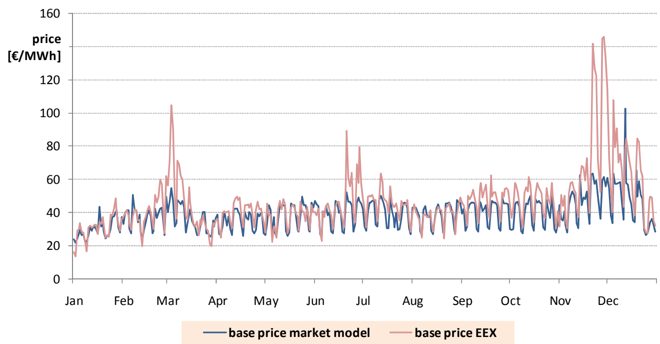

Fig. 3. Results of the wholesale market model for Germany (ref. year: 2005).

C. *Load flow calculations*

1) *Reduced sample network*

The load flow calculations are performed on a reduced sample network which is developed to reproduce realistic situations of the transmission system in the Central Western European (CWE) region (Belgium, France, Germany, Luxembourg, and the Netherlands). To take possible loop-flows into consideration, also nodes in Austria, the Czech Republic, Poland, and Switzerland are modeled. The detailed features of the sample network and the utilized data are described in [5] for the German system. Figure 4 gives an overview of the structure of the network model. In the German part, the 31 nodes are also allocated to the 16 federal states. This information is useful as relevant statistical data are often differentiated between the federal states. These data comprise current and expected values of installed capacity in renewables like wind energy, photovoltaic, biomass etc. as well as the use of combined heat and power. Another important input for the modeling is the development of the population which is correlated to the electric load. The large conventional power plants are explicitly allocated to the network nodes utilizing a detailed data base.

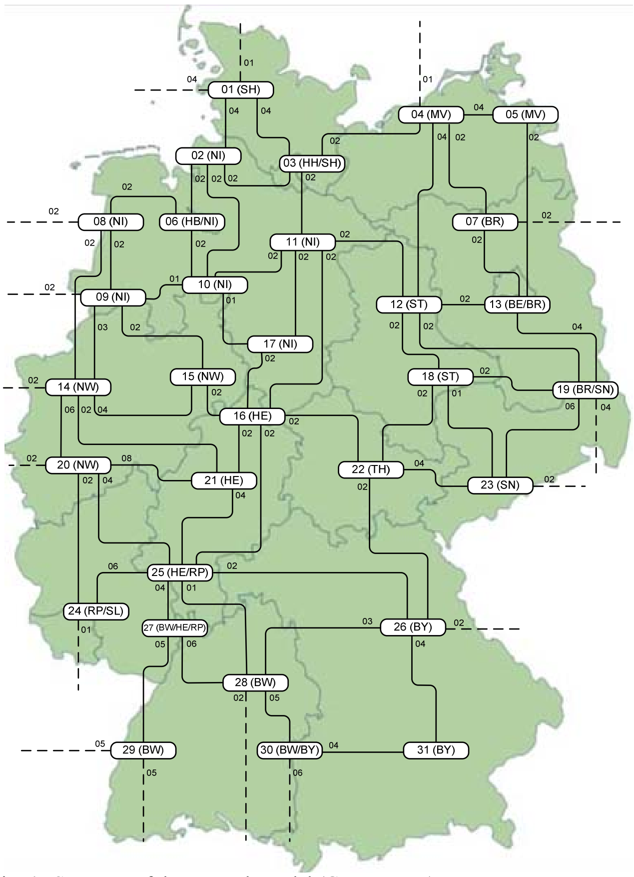

Fig. 4. Structure of the network model (German part).

The model accuracy of the other regarded regions and markets is nearly the same as for Germany although the focus of the entire model are the implications for the German market and the transmission system, e.g. line loadings or necessary network upgrades. The numbers of nodes of the other regions are the following:

- Belgium: 4 nodes;
- France: 13 nodes;
- The Netherlands: 9 nodes.

Luxembourg is not modeled explicitly as its main part is associated to the German control block and it does not have an own power exchange. The existing power plants in these regions are also included in a data base to model the market and to allocate the calculated results to the nodes.

In order to improve the computation time of the model and most notably of the load flow calculations, the calculations are not carried out for each of the 8760 hours of a year. This number is reduced by deriving typical days. One year is divided into four seasons and each season is made up of three days, i.e. one working day, one Saturday and one Sunday. This simplification leads to 12 days and 288 hours, respectively, that have to be calculated. Another advantage of this approach is that calendaric details like the type of the first day of the year and leap years can be neglected. The structure of the modeled time steps is always the same and independent of the actual year.

2) Influencing factors on the line loading

The following two figures demonstrate the impact of the line loading from the load curve and from must-run generation, i.e. infeed from renewables and combined heat power. Figure 5 shows the 24 hourly values of the load and the respective residual load in Germany. The pictured day is the Saturday in season 1 (January to March) in 2007. The residual load results from the subtraction of the must-run generation from the actual load. To identify the impact of the wind infeed, these values are increased by 10 and 20 %. The load curve in figure 5 has the typical trend with two peaks in hour 12 and 19, respectively. The must-run generation is very high until hour 17 leading to a low residual load. As the must-run generation decreases considerably in the evening, the residual load increases.

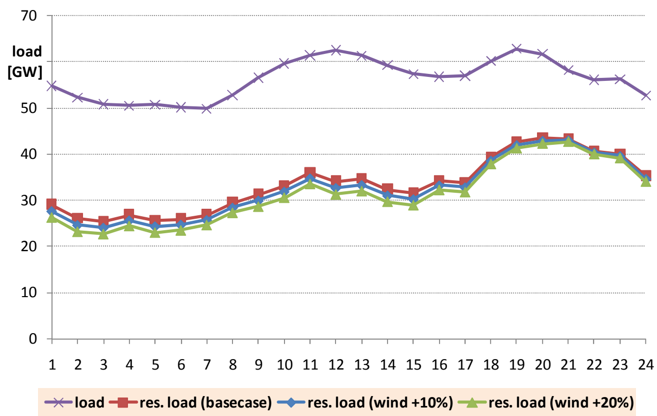

Fig. 5. Load and residual load in Germany for a Saturday in season 1, 2007.

In Germany, wind energy has a high share of the total installed capacity in renewables. These plants are located mainly in the northern part of Germany and for the future, large offshore installations in the North and Baltic Sea are planned. Therefore, the loading of the transmission lines in this region has to be regarded carefully. As an example, the loading of the two 380 kV lines connecting nodes 6 and 8 is shown in figure 6 for the same period as in figure 5. These lines also have a strong impact on the physical flow between Germany and the Netherlands as one of the cross-border connections is connected to node 8.

The results in figure 6 clarify the strong impact of the must-run generation on the line loading. In hours with a high must-run generation, the loading reaches values of more than 60 % of the thermal limit. Due to a lower infeed in the evening, the loading decreases to a minimum of 20 %.

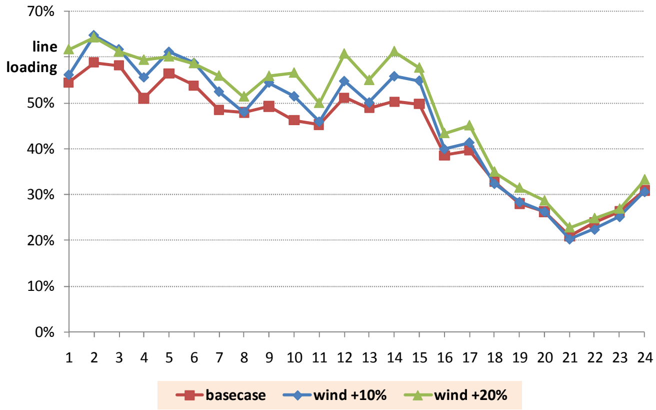

Fig. 6. Loading of the lines connecting nodes 6 and 8.

These exemplarily results also highlight an important aspect for the market coupling. During the regarded day, the amount of energy traded between Germany and the Netherlands does not change, but the physical flow on the cross-border lines changes considerably due to the altered generation pattern in Germany. Net transfer capacities (NTC) that are calculated for only a few situations per year cannot take the impacts of the generation pattern of the market regions into account. Flow-based approaches are able to incorporate physical restrictions into the calculation of feasible market equilibriums.

3) Determination of the PTDF matrix

The PTDF matrix $\boldsymbol{M}$ has the dimension $(m \times n)$ with the total number of lines m and the number of nodes n. As the loading and the sensitivity of parallel lines is the same, the respective rows of the matrix are deleted to reduce the number of constrains for the market coupling optimization.

In order to get a linear mapping of the changing nodal or zonal inputs to the line loadings, three general methods to calculate the PTDF matrix are mentioned in the literature:

- The method utilized in this work is based on the comparison of the solution of two AC load flow calculations. The nodal inputs in the base case are increased by a given amount, e.g. 100 MW, for each node except for the slack node. The flows on each of the lines are compared to the flows in the base case. Therefore, the resulting PTDF matrix is related to the base case and the matrix elements depend on the selection of the slack node, also denoted as hub. This method is also proposed in [6], [7] and will be described in detail afterwards.
- An alternative approach published in [8], [9] uses the Jacobian matrix based on the DC load flow equations. As the matrix operations are infinitesimal and not incremental, the sensitivities are independent of the slack node. For this method, only one AC load flow calculation has to be performed to determine the base case with the respective voltage profile and the distribution of the network losses. Due to the necessary inversion of the Jacobian matrix, this method might cause numerical problems if the matrix is nearly singular.
- The simplest way to determine the PTDF matrix is the direct utilization of the DC load flow equations [10]. By neglecting network losses and absolute voltage differences, the equations allow a linear mapping of nodal inputs to line loadings. The DC load flow equations can also be incorporated directly in the economic dispatch problem like in [11]. The independency from a base case is an advantage and a disadvantage at the same time. Except for topology changes, the PTDF matrix remains unaltered, but the linearization error is considerably higher than in the two other methods.

The base case for every modeled hour is defined as the market equilibriums of the four regarded regions without any cross-border transaction, i.e. the regional generation is equal to the regional load. In some cases, the available power plants in the Netherlands cannot cover the regional load so that the market model does not lead to a balance of generation and load. To get a feasible solution, a fixed import has to be placed in the market model. As described in the prior section, the market model provides the aggregated nodal inputs and outputs for every region so that the load flow and the PTDF matrix can be calculated.

The developed network model consists of 57 nodes in the four regarded regions; the total number of lines is 380 and 177 without parallel lines, respectively. The elements of $\boldsymbol{M}$ are related to a specific node, the slack node. In the network model, the slack is fixed to node 20 at the western German border. Therefore, the element

$$M_{i,k} = \frac{\Delta F_i}{\Delta P_k}, \text{with } i = 1 \dots m, k = 1 \dots n \tag{1}$$

represents the changing flow ΔF_i on line i, due to an additional input in node k. The additional output is always in the slack node so that the respective column in the PTDF matrix is zero. The impact of a transaction $\Delta P_{A \to B}$ between node A and B on line i is calculated as follows:

$$\Delta F_i = \Delta P_{A \to B} \cdot \left(M_{i,A} - M_{i,B}\right). \tag{2}$$

Despite the dependency of the elements of $\boldsymbol{M}$ to the selection of the slack node, the impact of a defined transaction between two nodes is independent of this selection. The linear relation between nodal input and line loading leads to transitivity of the transactions, so that ΔF_i in (2) is independent of the slack node. This property is narrowed a little because of the changed distribution of the network losses.

The single elements of $\boldsymbol{M}$ are calculated based on the increased inputs ΔP_k in the nodes. The amount of ΔP_k has an impact on the sensitivity due to the nonlinear AC load flow equations. But this impact is nearly negligible in this network model as shown in table I. The values in the first three rows show the maximum deviation between the determination of the PTDF based on a 10 MW and 1000 MW transaction, compared to a 100 MW transaction. The notations $M_{i,4}$ and $M_{i,31}$, with $i = 1 \dots m$, symbolize the increased generation in nodes 4 and 31, respectively, while $M_{i,4 \to 31}$ symbolizes a transaction between node 4 and 31. Therefore, the deviation between the superposed factors $M_{i,4} - M_{i,31}$ and the direct calculation are given in the last line of table I.

The results show that especially the deviations between the 10 MW and the 100 MW transactions are very small, and that the assumed linearity of the PTDFs is valid. The higher deviations for the 1000 MW transactions are caused by the increased losses which are covered by the slack node. In some cases, the total network losses are increased by up to 200 MW. The linearity of the PTDFs is also stated in [6] for calculations of the whole UCTE network.

TABLE I
MAXIMUM DEVIATION OF THE PTDFS.

	10 MW	100 MW	1000 MW
$M_{i,4}$	0.0290%	-	0.2467%
$M_{i,31}$	0.0160%	-	0.1247%
$M_{i,4\rightarrow 31}$	0.0240%	-	0.2186%
$(M_{i,4}-M_{i,31})-M_{i,4\rightarrow 31}$	0.0100%	0.0140%	0.1547%

Apart from the determination of the PTDF matrix, the capacity limits of each line are relevant for the market coupling algorithm. As the network model and the optimization is based on nodal inputs and not on aggregated zones, the definition of so called flow gates or NTC values on the borders between the regions is not necessary. Therefore, the calculated line loading is constrained by the thermal limit F^{max}, which is assumed to be equal for all lines in the model.

To ensure the $(n-1)$-criterion of the transmission system, the outage of every line has to be considered. Due to the changed topology, the PTDF matrix is re-calculated for every contingency, leading to a set of new constrains for the market coupling algorithm. Another important question in this context is the optimal frequency of the computation of the sensitivities in practice. Due to the linearization and the uncertainty about the actual generation and load pattern, an hourly estimation of base cases and respective PTDF matrices would be optimal, leading to a high complexity of the congestion forecasting [6].

D. Market coupling algorithm

The market coupling algorithm optimizes the cross-border transactions with regard to the network constraints. As long term contracts are neglected in the market model, also long term auctions for the cross-border capacity are disregarded in the simulation.

The goal of the algorithm is to find the optimal allocation of generation in the regarded system. The optimum is defined as the maximum of the system-wide economic welfare subject to the limited transmission capacities. In case of a complete price inelasticity of the demand, the problem can also be formulated as the minimization of the generation costs. With the resulting nodal inputs, the load flow is re-calculated to rate the utilization of the congested lines and with it the efficiency of the congestion management.

1) Objective function

The objective of the market coupling algorithm is the minimization of the generation costs as the demand is assumed to be fixed and price inelastic. Therefore, the actual costs for the consumers to cover their demand and the congestion rent resulting from price differences between the regions are not regarded in the following. The objective can be formulated as

$$\min_{P_{k,j}} \sum_{k} \sum_{j} C_{k,j} \cdot P_{k,j}\,, \text{with } k = 1 \dots n, j = 1 \dots J \tag{3}$$

where $C_{k,j}$ represents the marginal costs of power plant j, which is located at node k. The nodal input P_k is the sum of the inputs of all plants $P_{k,j}$ at node k. The input of every plant is limited by the installed capacity and the total generation must be equal to the total residual load of the four regarded regions. The consideration of the network constraints based on the PTDF matrix is discussed in the next section together with the generation shift method.

2) Generation shift

The simplest way to implement the generation shift, i.e. the change of the generation pattern due to an additional import or export, into the market coupling algorithm is the pro-rata method. This method is characterized by a fixed share of the nodal inputs related to the total input of the respective region. This might lead to situations in which the nodal input is higher than the installed capacity at this node. Especially power plants in the base load do not change their operating point (which is near to 100 % of the installed capacity). However, the bids and the aggregated bidding curve at the power exchanges are not associated to the nodes in practice. Due to this lack of information, a merit-order based allocation of the generation shift is difficult to implement. In the proposed model the location of the bids is known, so that the error and the respective loss of efficiency induced by the pro-rata generation shift can be determined.

The pro-rata generation shift leads to a considerable simplification of the optimization as the nodal inputs can be formulated based on the total input of each region. The original $(m \times n)$ sensitivity matrix $\boldsymbol{M}$ is transformed to an $(m \times 4)$ matrix $\boldsymbol{M'}$ with four columns for the four regarded regions. As shown in the prior section, the changing flow on line i can be calculated based on the changing nodal inputs ΔP_k^{MC}, with $k = 1 \dots n$. The actual flow F_i^{MC} results from the appropriately signed sum of the altered flow and the flow in the base case:

$$\begin{bmatrix} F_1^{MC} \\ \vdots \\ F_m^{MC} \end{bmatrix} = \underbrace{\begin{bmatrix} M_{11} & \cdots & M_{1n} \\ \vdots & \ddots & \vdots \\ M_{m1} & & M_{mn} \end{bmatrix}}_{\boldsymbol{M}} \cdot \begin{bmatrix} \Delta P_1^{MC} \\ \vdots \\ \Delta P_n^{MC} \end{bmatrix} + \begin{bmatrix} F_1^{BC} \\ \vdots \\ F_m^{BC} \end{bmatrix}. \tag{4}$$

Due to possible negative values of the flows F_i^{MC}, the following inequality has to be fulfilled:

$$-\begin{bmatrix} F_1^{max} \\ \vdots \\ F_m^{max} \end{bmatrix} \le \begin{bmatrix} F_1^{MC} \\ \vdots \\ F_m^{MC} \end{bmatrix} \le \begin{bmatrix} F_1^{max} \\ \vdots \\ F_m^{max} \end{bmatrix}. \tag{5}$$

The changing nodal inputs ΔP_k^{MC} are not arbitrarily variable due to the pro-rata generation shift. The share of each node referring to the total input of the respective region is the same as in the base case. This relation can be expressed by the weighting matrix $\boldsymbol{W}$, containing the shares P_k^{BC}/P_{reg}^{BC} of each node in the base case and the total change of the input in each region ΔP_{reg}^{MC}. This $(n \times 4)$ matrix is arranged as follows: In the first four rows, the shares of the four nodes in the region Belgium (BE) are entered each in the first column. In the next 31 rows, the shares in Germany (DE) are entered in the second column. The same is done for France (FR) and the Netherlands (NL).

$$\begin{bmatrix} \Delta P_1^{MC} \\ \vdots \\ \Delta P_n^{MC} \end{bmatrix} = \underbrace{\begin{bmatrix} P_1^{BC}/P_{BE}^{BC} & 0 & 0 & 0 \\ \vdots & & & \\ P_4^{BC}/P_{BE}^{BC} & 0 & 0 & 0 \\ 0 & P_5^{BC}/P_{DE}^{BC} & 0 & 0 \\ & \vdots & & \end{bmatrix}}_{\boldsymbol{W}} \cdot \begin{bmatrix} \Delta P_{BE}^{MC} \\ \Delta P_{DE}^{MC} \\ \Delta P_{FR}^{MC} \\ \Delta P_{NL}^{MC} \end{bmatrix}. \tag{6}$$

Now, the new sensitivity matrix $\boldsymbol{M'} = \boldsymbol{M} \cdot \boldsymbol{W}$ can be calculated. The matrix elements are exclusively related to the base case and therefore not variable in the optimization. The constraints of the line flows are derived according to the total generation in the four regarded regions:

$$-\begin{bmatrix} F_1^{max} \\ \vdots \\ F_m^{max} \end{bmatrix} \leq \boldsymbol{M'} \cdot \begin{bmatrix} \Delta P_{BE}^{MC} \\ \Delta P_{DE}^{MC} \\ \Delta P_{FR}^{MC} \\ \Delta P_{NL}^{MC} \end{bmatrix} + \begin{bmatrix} F_1^{BC} \\ \vdots \\ F_m^{BC} \end{bmatrix} \leq \begin{bmatrix} F_1^{max} \\ \vdots \\ F_m^{max} \end{bmatrix}. \tag{7}$$

3) First results

The calculation of different load situations shows the general functionality of the proposed market coupling algorithm together with the network model. The total generation costs are reduced considerably compared to the base case without any transactions between the regarded regions. The network constraints are also met with the expected deviations due to the linear PTDF matrices and the pro-rata generation shift. Based on further results, an appropriate reliability margin for the maximum line loading has to be determined.

III. Conclusions

In this paper a combined network and market model is presented in order to evaluate the efficiency of the implementation of market coupling in the Central Western European region. Market coupling is utilized to allocate limited transmission capacity in a meshed electricity transmission system based on market-oriented rules. Therefore, both the physical load flow and the market results have to be considered. The use of PTDFs leads to a linear optimization problem for the market coupling algorithm.

With the proposed model it is possible to appraise different designs of market coupling in practice. In this context, the impact of the linearization of the load flow equations, the implementation of the generation shift, and the possibility to take $(n-1)$-situations into consideration are important questions. These points also lead to organizational topics, e.g. the centrally available information and the communication between the power exchanges as well as the definition of base cases and PTDF matrices by the involved system operators. From an economic point of view, the implications of market coupling for the different market players can be analyzed in detail and the value of network upgrades can be estimated.

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V. Biographies

Daniel Waniek received his diploma of industrial engineering in the field of European energy management in 2006 from Technische Universität Dortmund, Germany. He is working at Technische Universität Dortmund, Institute of Power Systems and Power Economics, on his doctoral degree in the field of market-oriented planning and operation of dispersed generation in a future energy supply system.

Christian Rehtanz received his diploma degree in electrical engineering in 1994 and his Ph.D. in 1997 at Technische Universität Dortmund, Germany. From 2000 he was with ABB Corporate Research, Switzerland and from 2003 Head of Technology for the global ABB business area Power Systems. From 2005 he was Director of ABB Corporate Research in China. From 2007 he is professor and head of the Institute of Power Systems and Power Economics at Technische Universität Dortmund, Germany. His research activities include technologies for network enhancement and congestion relief like stability assessment, wide-area monitoring, protection, and coordinated FACTS- and HVDC-control.

Edmund Handschin received his diploma in electrical engineering in 1965 from the Swiss Federal Institute of Technology, Zurich, Switzerland, and his Ph.D. in 1968 from the Imperial College London, UK. From 1969 until 1974 he was staff member of the Brown Boveri Research Center in Baden, Switzerland. From 1974 until 2007 he has been Professor of the Institute of Power Systems and Power Economics at Technische Universität Dortmund, Germany.