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Considering Start-Up Costs and Risk Premia in a Power Generation Cost Model

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***Abstract*--The market price for electrical energy is one of the main decisive factors for operational and strategic questions of power generation companies (PGC). Using market simulation methods which simulate the market for electrical energy the price development can be investigated. However, the deficit of typical market simulation methods is, that these methods in general not consider all cost components of the power generation from the point of view of a PGC. Especially the consideration of start-up costs as well as the financial hedge of power plant outages by risk premia are supposed to be relevant cost components concerning the power generation and has to be analyzed and evaluated in detail.**

Considering these circumstances, this paper presents an extended market simulation method for the investigation of the price development in the central European market for electrical energy under consideration of start-up costs and risk premia.

Keywords: generation cost components, risk premia, start-up costs, unit commitment, market simulation, price development

I. Motivation

Due to the intensified competition between the PGC in the liberalized European electricity market the behavior of the companies which originally minimized their power generation costs, has changed to a maximization of the contribution margin [1]. The contribution margin represents the difference of the revenues of energy trades and the costs for generating and purchasing electrical energy. Therefore, the decisive factor is the market price for electrical energy. In consequence, it is essential to investigate the market price to evaluate the economic profitability of existing and new power plants as well as for mid- and long-term power trading [2].

Market simulation methods which simulate the market for electrical energy are an acknowledged method for the investigation of the market price development based on the power generation costs [3]. In general, the advantage of market simulation methods is the potential to consider several influencing factors concerning the power generation and demand and in consequence the main influencing factors on the market price for electrical energy [4]. However, concerning the price modeling typical market simulation methods only consider the power generation costs based on fuel and emission costs, so further cost components are neglected [5].

In this paper an extended market simulation method for the investigation of the price development in the central European market for electrical energy is presented. Therefore, an existing market simulation method that provides the possibility to investigate the development of the market price for electrical energy has been extended to incorporate further power generation cost components of thermal power plants. These cost components consist on the one hand of real and avoided start-up costs and on the other hand of the financial hedge of power plant outages by risk premia. Finally, the development of the market price in the European market for electrical energy has been investigated based on the power generation costs using the extended market simulation method for the years 2005 to 2007.

In the following section, the considered system and its relevant components for a market simulation method are defined (section II. A.). In addition the cost components in power generation are analyzed (section II. B.) and the modeling of start-up costs as well as the financial hedge of power plant outages by risk premia is described in detail (section II. C.). In section III the two-stage market simulation method is presented. The results of exemplary investigations of the market simulation method considering the further cost components are shown for the years 2005 to 2007 in section IV. By means of a comparison of different simulation results, the relevance of start-up costs and risk premia in a power generation cost model will be shown.

II. Optimization Model And Further Development

A. System Components

For investigations of the market price development using market simulation methods the definition of the relevant components of the considered system, the geographical focus and the time horizon is required.

Due to an increasing cross-border trade in central Europe caused by the liberalization and the introduction of basic conditions for the congestion management an isolated model of national electricity markets is not appropriate anymore [6], [7]. Hence, the investigated system consists of the central European countries based on the division into different regions by the European Commission concerning the congestion management [7]. Thus, the considered system comprises the following countries: Germany, Netherlands, Belgium, Luxemburg, France, Italy, Switzerland, Austria, Slovenia, Hungary, Czech Republic, Slovakia, Poland, the members of the Nordel association (Denmark, Finland, Norway, Sweden) and the Iberian Peninsula consisting of Spain and Portugal (Fig. 1).

Each country represents one market area. The cross-border transmission network is also part of the investigated system in order to consider the power transfer between the neighboring countries. The energy sector of each market area is subdivided into a supply and a demand section. The power supply is provided by PGC which generate electrical energy in thermal and hydro power plants and additionally in other power plants, e. g. renewable energy units. The demand sector is separated in scheduled load and reserve (Fig. 1).

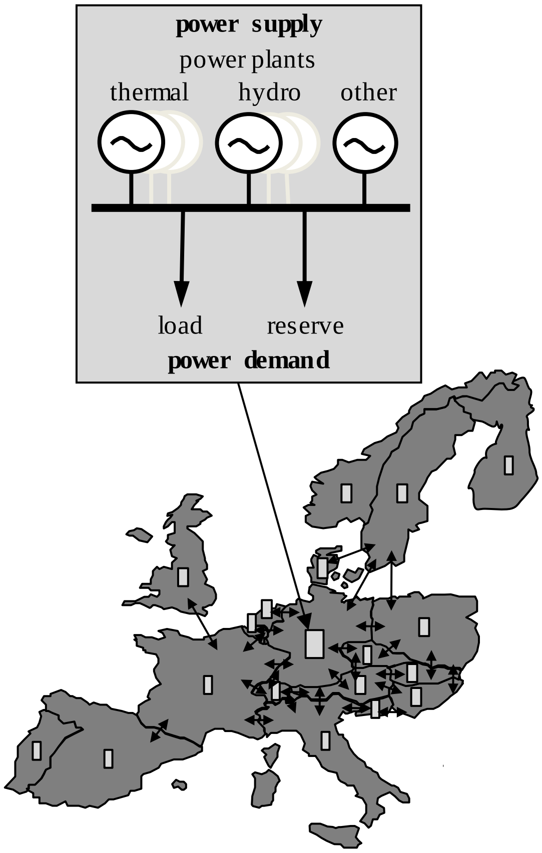

Fig. 1. System overview.

The considered time horizon for the market simulation is in general one year. The time pattern is determined to one hour. Thus, on the one hand technical restrictions of power generation [8], esp. of thermal power plants, e. g. minimum up- and down-times, start-up procedures, can be considered. On the other hand, simulated market prices can be generated and compared to real market prices in each hour. In addition to the mentioned technical restrictions of power generation, the minimum and maximum power level as well as non-linear efficiency curves of the power plants are considered. In addition, the interconnections between the reservoirs of the hydro power plants and the distribution of the limited available water as well as the natural inflow to the reservoirs are considered. Since hydro power plants have negligible generation costs, the power generation planning determines the economically optimal schedule considering the technical restrictions. With the stand-by power plants a time-dependent demand can be covered. This leads to an optimization problem of minimizing the system generation costs for the power generation of thermal power plants as well as the optimal use of the water quantity in hydro power plants [9].

B. Cost Components in the power generation

The costs of power generation with thermal units comprise both fixed and variable costs [10]. The PGC offer in general their generated electricity to the market based on the variable costs. These costs are dependent on the operation of a power plant and hence a function of the generated power. The variable generation costs (C) of a thermal power plant (PP) consist of costs during the steady state operation (SS) for the fuel as well as emission certificates ($C_{ss,fec}$) and additional work-dependent costs ($C_{ss,add}$), e. g. for auxiliary materials such as lube oil, fumes desulphurization as well as operating-time dependent maintenance [11]. In addition, start-up costs have to be considered comprising costs for fuel dependent on standstill and start-up costs independent on standstill which represent the costs for reduced residual lifetime due to extra-mechanical wear of the engines during start-up [12]. The consideration of these cost components yields the following optimization problem (1).

$$\min\left(\sum_{t=1}^{n}\sum_{PP\in S} C_{ss,fec,t,PP} + C_{ss,add,t,PP} + C_{start,t,PP}\right) \qquad (1)$$

Assuming a perfect competition the unit commitment under consideration of a minimization of the costs is identical to the unit commitment considering a maximization of the contribution margin [13], [14].

The results of the optimization procedure are hourly power generation schedules in which the quantity of generated power is determined for each power plant. In a subsequent stage cost curves are generated. For this purpose the evaluation of the variable costs for each power plant is necessary. In addition to the costs for fuel and emission certificates as well as the additional work dependent costs further components for the consideration of the distribution of start-up costs as well as the financial hedge of power plant outages by risk premia should be considered.

C. Considering start-up costs and risk premia

1) Start-up costs

In the market simulation method two kinds of start-up costs, real and avoided costs, are considered. Real start-up costs (SC_{real}) occur for each start-up procedure of a thermal power plant. These costs are composed of fuel costs which are dependent on the previous shutdown period and costs in consequence of higher mechanical wear during the start-up procedure which are independent on the previous shutdown period. Positive specific start-up costs (PSC) are calculated individually for each hour of the operation period after a start-up according to (2) in order to distribute the total costs [15] as a function of the produced power (P), the generation costs (GC) and a forecast for the market price. The market price is a result of the market simulation so that in this modeling the system marginal costs (MC) which are a result of the optimization are chosen as a market price forecast.

$$PSC_t = \begin{cases} \frac{1}{\sum_{t_{on}}^{t_{off}} P_t \frac{MC_t}{GC_t}} \frac{MC_t}{GC_t} SC_{real} & \text{, if } \frac{GC_t}{MC_t} < 1 \\ 0 & \text{, if } \frac{GC_t}{MC_t} \geq 1 \end{cases} \quad (2)$$

Fig. 2 shows an exemplary evaluation of the positive specific start-up costs.

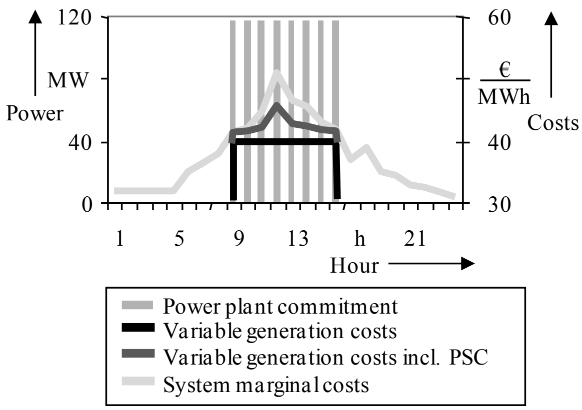

Fig. 2. Example for the evaluation of PSC.

Negative specific start-up costs (NSC) consider the behavior of PGC during periods of low demand and low market prices, when many peak- and mid-load units might become uneconomical based on their variable operational costs and expected spot prices. To avoid losses these units could be shut down during this period. Consequently, they could be started-up again in the following period of high demand and high market prices which leads to start-up costs representing negative opportunity costs for the PGC [2], [5]. Thus, PGC have the incentive of bidding below their operational costs to guarantee the acceptance of the bid during the period of low demand. Therefore start-up costs are avoided ($SC_{avoided}$). From the point of view of a PGC the costs can be distributed to each hour in the respective off-peak period as negative specific start-up costs as a function of the produced power (P) and the ratio of generation costs (GC) and system marginal costs (MC) which are used as a market price forecast. They are calculated individually for each hour in which the marginal costs are lower than the generation costs according to (3).

$$NSC_t = \begin{cases} \frac{1}{\sum_{\text{off-peak period}} P_t \frac{GC_t}{MC_t}} \frac{GC_t}{MC_t} SC_{avoided} & \text{, if } \frac{MC_t}{GC_t} < 1 \\ 0 & \text{, if } \frac{MC_t}{GC_t} \geq 1 \end{cases} \quad (3)$$

Fig. 3 shows an exemplary evaluation of the NSC.

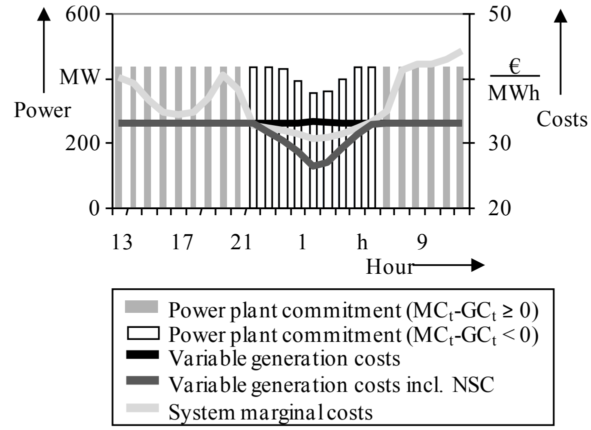

Fig. 3. Example for the evaluation of NSC.

The PSC will be added to the variable costs in stationary operation, the NSC will be subtracted.

2) Risk premia

During the operation of their power plants and the selling of the generated power the PGC must cope with uncertainties regarding deficits in the energy balance due to power plant outages. The hedge against the risks leads to additional costs which must be added to the generation costs. Risk premia provide the possibility to consider financial hedges of power plant outages [16]. They are derived from non-disposable outages of thermal power plants. For the evaluation of the risk premia the outages must be modeled as realistic as possible. In the presented market simulation method the outages are figured out with a stochastic drawing. The relevant input data for the drawing is created under consideration of available data regarding outages which have been published by PGC [17], [18] and VGB e.V. [19].

Due to non-disposable outages the unavailable power in the system must be substituted. The substitution is carried out with increasing the load of units which are operated in part load and with the start-up of gas turbines. The substituting units are chosen in ascending order of generation costs so that a cost optimized schedule is still guaranteed. The risk premium (RP) can be calculated individually for each hour from the additional generation costs for the substitution ($C_{Substitution}$), the avoided generation costs due to the outages (C_{Outage}) and the generated power (P) according to (4). Fig. 4 shows the procedure of evaluating the risk premia.

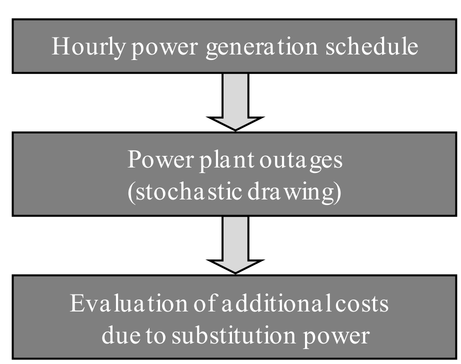

Fig. 4. Evaluation of risk premia.

$$RP_t = \frac{C_{Substitution,t} - C_{Outage,t}}{P_t} \quad (4)$$

Additionally to this risk premium which includes the outages of all thermal units, a risk premium differentiated by the fuel type (FT) can be evaluated according to (5).

$$RP_t\,(FT) = \frac{C_{Substitution,t}(FT) - C_{Outage,t}(FT)}{P_t(FT)} \quad (5)$$

Because an explicit relation between a substituting unit and an unit which is in an outage is impossbile, the total costs for the substitution are distributed to substitution costs per fuel type. This is carried out under consideration of the missing power due to the outages (P_{Outage}) according to (6).

$$C_{Substitution,t}(FT) = C_{Substitution,t} \frac{P_{Outage,t}(FT)}{P_{Outage,\,t}} \quad (6)$$

The risk premium will be added to the variable costs in stationary operation to consider financial hedges of power plant outages in the cost curves.

III. Market Simulation Method

Based on the previous analysis, a two-stage competitive market simulation method consisting of a power generation planning and a cross-border price matching was extended. Fig. 5 gives an overview of the method [9].

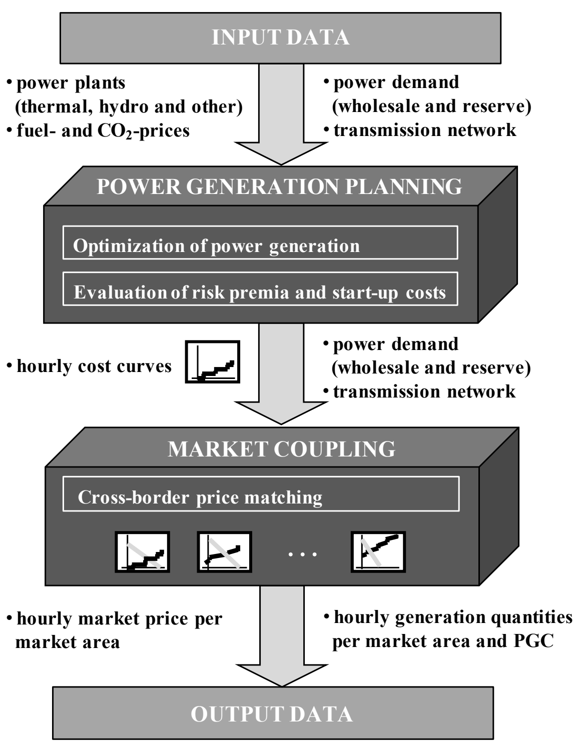

Fig. 5. Two-stage competitive market simulation method.

The market simulation method using power generation planning – which optimizes the scheduled operation of the power plants by minimizing generation costs under consideration of the technical and economical properties of the system presented in section II. A. – yields cost curves of the power generation [20]. These cost curves comprise also the newly considered cost components, both the evaluated risk premia and real and avoided start-up costs. The power generation cost curves are passed on to the subsequent market coupling. The market coupling includes a cross-border matching that is realized by maximizing the social welfare under consideration of the energy balance and the transmission network [21]. The input data consists of the cross-border capacities for the system, the cost curves which result from the power generation planning and the demand curves for each market area. The results of the market coupling are the hourly market price for each market area and the hourly generation quantity matched for each market area and PGC.

IV. Investigations And Results

In the following, the results of the two-stage market simulation method for the central European power market for electrical energy are presented for the investigated years 2005, 2006 and 2007. The optimal scheduled operation of the power plants is determined and the subsequent market coupling is realized ex-post under consideration of historical data of the European power market [2].

The objective of the investigations is to evaluate the market simulation method for modeling synthetical market prices based on power generation costs. Therefore, the simulated market prices will be compared with historical market prices at European power exchanges (backtesting). At first, the results will be analyzed regarding the power generation to verify the simulation method as well as the data model which is an essential requirement for further investigations regarding the market price.

Concerning this matter, Fig. 6 compares the historical power generation [23] and the power generation using the market simulation method separately for each fuel type and country (regions resp.) for the years 2005, 2006 and 2007 (annual average). In general, the results show that the real power generation by fuel type is on the same level compared with the simulation results which allows further investigations regarding the market price.

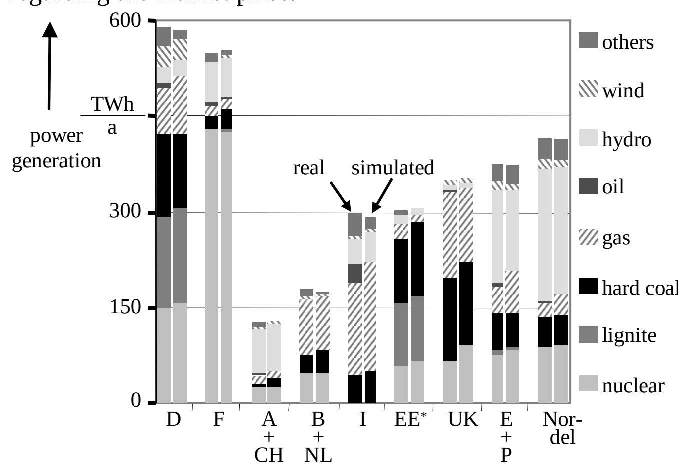

Fig. 6. Annual Power generation separated by fuel type; comparison historical data vs. simulation results in the European countries (average 2005 to 2007).

In the following, the results for the market price will be analyzed in detail. At first, the influence of the different cost components will be investigated. Therefore, three scenarios with focus on the market prices (MP) in Germany have been simulated:

- GC: The simulation prices are based on bids with conventional generation costs without the additional cost components.
- GC+SC: The simulation prices are based on bids with conventional generation costs and both positive and negative start-up costs.
- GC+SC+RP: The simulation prices are based on bids with conventional generation costs, start-up costs and risk premia.

Fig. 7 compares the historical market prices of the European Energy Exchange (spot market EEX, Germany) [24] and the simulation prices of Germany using the power generation cost model by the hourly average price on all weekdays for the considered scenarios. In general, the results of the three scenarios show varying differences between real market prices and simulation prices dependent on the daytime. Basically, there is a slight underestimation in a few peak- (esp. at noon on workdays) and an overestimation in offpeak-hours (esp. at weekend) of the market price. The difference in offpeak-hours can be caused e.g. by the costs for the emission certificates which are completely included in the power generation costs of the power plants in the market simulation. Therefore, based on the results of the market simulation method it can be inferred that probably the costs for emission certificates are not totally included in the market price especially during offpeak-hours. The underestimation in peak-hours can be caused e.g. by hours with shortage of electrical energy which can occur even in a perfect competition [25].

Furthermore, the comparison of the scenario results shows better estimations of the real market prices during offpeak and peak periods considering the introduced additional generation cost components. In offpeak-hours the avoided start-up costs influence the market prices whereas in peak-hours an effect of both the positive specific start-up costs and the risk premia can be observed.

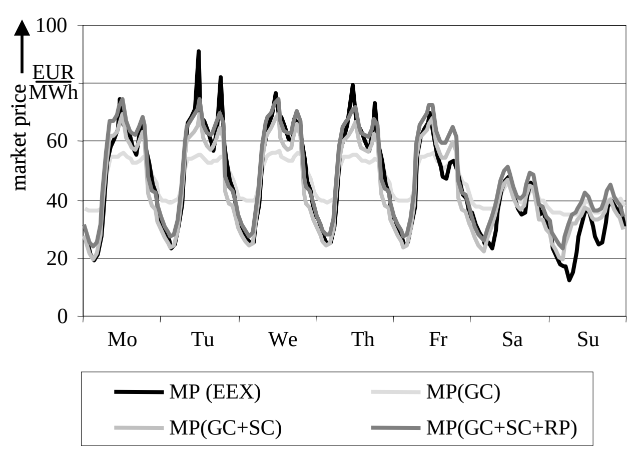

Fig. 7. Hourly average of the market prices on all weekdays in Germany (2005 to 2007).

Based on these results, the following investigations focus on a comparison of the simulation prices and the market prices in Germany, France and Netherlands due to the importance of these power markets and the comparatively high liquidity of their power exchanges (EEX in Germany [24], Powernext in France [26], APX in Netherlands [27]). The simulations have been done under consideration of start-up costs and risk premia (scenario GC+SC+RP) due to the better estimation of the market price compared to the other scenarios (Fig. 7).

Fig. 8 shows the results regarding the market prices separately for Germany, France and Netherlands in the years 2005, 2006 and 2007. In addition, the results are distinguished referring the market prices in base-, peak- and offpeak-hours. Basically, analogous to the previous investigation the results show an underestimation in peak- and an overestimation in offpeak-hours. However, the results generally confirm that the real market price is on the same level compared with the simulation results in each country. In addition, the different price levels of the investigated years can be reproduced by the power generation cost model.

In conclusion, the investigations confirm the application of the presented method for modeling market prices in the European power market. Furthermore, the results show that the simulation prices under consideration of the additional cost components (start-up costs and risk premia) become more realistic in peak- as well as in offpeak-hours and have to be modeled for investigating the market price for electrical energy.

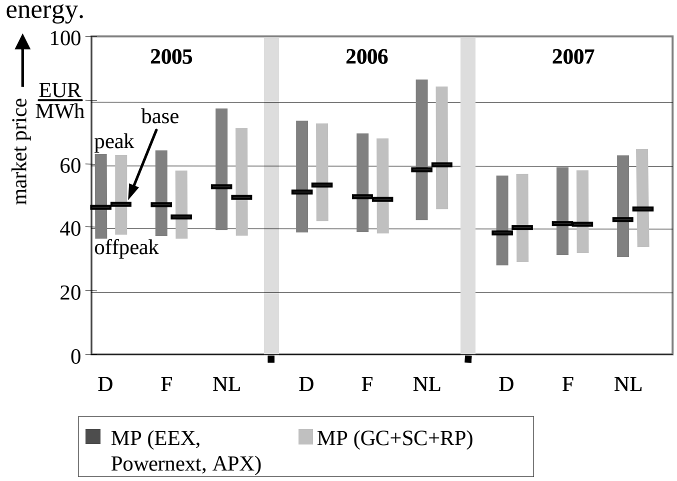

Fig. 8. Market prices in Germany, France and Netherlands separately for base-, peak- and offpeak-hours (2005 to 2007).

V. Conclusion

Due to the intensified power trading in the liberalized market for electrical energy the market price has become a decisive factor for operational and strategic questions of PGC. Using market simulation methods the development of the market price is investigated based on the power generation costs. Therefore, the different power generation cost components have to be analyzed in detail.

In addition to typical power generation costs components, such as costs for fuel and emission certificates, the presented method enables to consider on the one hand real and avoided start-up costs and on the other hand additional costs due to the financial hedge of power plant outages, so-called risk premia. Using this power generation cost model the market for electrical energy can be simulated to investigate the development of the market price.

The price development in the European market for electrical energy has been investigated based on results of the power generation cost model for the years 2005 to 2007. In conclusion, the results show that better estimations of the real market prices can be achieved considering real and avoided start-up costs as well as risk premia. Especially the analysis concerning the spread between offpeak- and peak-prices shows that under consideration of start-up costs and risk premia the simulation prices become more realistic and lead to a better understanding of the market price which proves the necessity to consider these cost components for investigating the market price for electrical energy. In addition, an exemplary comparison of the development of real market prices and simulation prices in Germany, France and Netherlands in the years 2005, 2006 and 2007 confirms the application of the presented method for modeling market prices in the European power market.

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VII. Biographies

Tobias Mirbach was born in Viersen, Germany, on October 7, 1978. He studied Electrical Engineering at RWTH Aachen University where he graduated in 2005 (Dipl.-Ing.).
Since 2005 he is member of the academic staff of the Institute of Power Systems and Power Economics at RWTH Aachen University. Since 2008 he is head of the research group "Power Generation and Trading". His present fields of interest include market simulation and the investigation of the development of the market price for electrical energy. Furthermore he has worked on research and industry projects in the field of congestion management, portfolio management and decision support for the extension of generating capacity.

Tobias Schuetze was born in Essen, Germany, on April 20, 1982. He studied Electrical Engineering at RWTH Aachen University where he graduated in 2008 (Dipl.-Ing.) and Business Administration at RWTH Aachen University where he graduated in 2009 (Dipl.-Wirt.-Ing.).
In his diploma thesis he worked on the extension of a market simulation method regarding further cost components of the power generation from the point of view of a PGC.
Since 2009 he is member of staff of Helmut Mauell Company. He works on the planning of instrumentation and control equipment for power plants.