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AUTHORS

Andreas Knaut

Martin Paschmann

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Institute of Energy Economics at the University of Cologne (EWI)
www.ewi.uni-koeln.de

Institute of Energy Economics
at the University of Cologne (EWI)

Alte Wagenfabrik
Vogelsanger Str. 321a
50827 Köln
Germany

Tel.: +49 (0)221 277 29-100
Fax: +49 (0)221 277 29-400
www.ewi.uni-koeln.de

CORRESPONDING AUTHOR

Martin Paschmann
Institute of Energy Economics at the University of Cologne (EWI)
martin.paschmann@ewi.uni-koeln.de

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Decoding Restricted Participation in Sequential Electricity Markets

Andreas Knaut[a], Martin Paschmann[a]

[a]*Institute of Energy Economics, University of Cologne, Vogelsanger Strasse 321a, 50827 Cologne, Germany.*

Abstract

Restricted participation in sequential markets may cause high price volatility and welfare losses. In this paper, we therefore analyze the drivers of restricted participation in the German intraday auction which is a short-term electricity market with quarter-hourly products. Applying a fundamental electricity market model with 15-minute temporal resolution, we identify the lack of sub-hourly market coupling being the most relevant driver of restricted participation. We derive a proxy for price volatility and find that full market coupling may trigger quarter-hourly price volatility to decrease by a factor close to four.

Keywords: sequential electricity markets, short-term market dynamics, electricity market interaction, short-term price formation, restricted market participation, price volatility

JEL classification: C13, C51, D44, D47, L94, Q21, Q41

1. Introduction

The increasing share of renewable energies has caused an exacerbated need of short-term trading opportunities for electricity. Forecast uncertainty and highly volatile feed-in profiles of renewable energies favor the trade of shorter contracts closer to the time of physical delivery (see, e.g., Weber (2010), Garnier and Madlener (2014) and Karanfil and Li (2017)). In this paper, we focus on the interaction of two sequential short-term electricity markets in Germany. The first market is the day-ahead auction with hourly products which is settled at noon one day before physical delivery. Second, we consider the intraday auction which allows the trade of quarter-hourly contracts three hours after the day-ahead market settlement.

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*Corresponding author:
Email address: `martin.paschmann@ewi.uni-koeln.de, +49 221 277 29 300` (Martin Paschmann)

This article is especially motivated through Knaut and Paschmann (2017) analyzing the impact of restricted participation in the day-ahead and intraday auction. The authors find that restricted participation may trigger both high price volatility as well as welfare losses. Based on these findings, we target to identify the underlying drivers of restricted participation in the German intraday auction. Our results are supposed to form the basis for evaluating countermeasures in order to reduce the respective inefficiencies.

In general, we consider four potential drivers of restricted participation: i) inertia as the state of not knowing[1], ii) costs of market entry, iii) inflexibility of power plants and iv) a lack of cross-border market coupling. In this article, we focus our attention on the latter three drivers as there is empirical evidence that the role of inertia is of minor relevance for the intraday auction. We conduct exemplary profitability analyses and find an indication that costs of market entry are not expected to prevent profit maximizing traders from participating in the intraday auction. In a next step, we set up a fundamental electricity market model with 15-minute temporal resolution which is essentially capable of replicating the price pattern observed in real-world data. We then disentangle the effects of power plant flexibility and market coupling on sub-hourly price volatility. Our analysis is motivated by the fact that cross-border trade may cause convergence of prices if sufficient transmission capacity is available (see, e.g., Zachmann (2008) and Parisio and Bosco (2008)) and thus the overall efficiency may increase. Indeed, our results suggest that the lack of cross-border trade is the major fundamental driver of restricted participation in the intraday auction.

Having identified the lack of sub-hourly market coupling as the most important driver, it may be beneficial for policy makers to urge the realization of the XBID project aiming to implement cross-border intraday trade on a 15-minute level in the internal European electricity market (EPEX SPOT SE, 2017c). Furthermore, additional market coupling on sub-hourly levels such as proposed for Germany, the Netherlands and France may be worth considering (EPEX SPOT SE, 2017a). To derive a proxy for the effectiveness of such measures, we evaluate the effect of additional sub-hourly market coupling on the price volatility within our modeling framework. Our results suggest that full market coupling on a quarter-hourly level may trigger the sub-hourly price volatility to decrease by a factor close to four.

Besides providing insights for policy makers, our results are also important for firms participating in the day-ahead and intraday auction as we are able to depict the most relevant drivers of the high price volatility observed. At first sight, the high price volatility may seem to be favorable for investments into power plant flexibility. Based on our findings, however, this may be a false conclusion. Therefore, investment decisions regarding flexible generation units should account for the impact of the targeted quarter-hourly market

[1] For more details on inertia of market participants see Doraszelski et al. (2016).

coupling on prices.

Finally, the methodological approach extends research so far as the temporal resolution of the model, to the best of our knowledge, is a unique feature compared to dispatch models that are most commonly applied in the existing literature. We clearly point out that simulating the power supply system with sub-hourly temporal resolution will become increasingly important. This is especially relevant to simulate investment decisions of flexible generation units with higher accuracy. At the same time, we are able to simulate the impact of different types of market coupling on the respective sequential market dynamics.

The remainder of this paper is organized as follows. We first briefly depict the main literature background. In Section 3 we then present our strategy how to decode the drivers of restricted participation in the German intraday auction. The respective analysis of the individual drivers considered is presented in detail within the following sections. Finally, we conclude in Section 6.

2. Literature Background

Focusing on the interaction of sequential markets, this paper is positioned in research surrounding market equilibria and the respective market outcome in sequential market configurations (see, e.g., Green (1973), Veit et al. (2006) and Pindyck (2001)). In the context of the power sector, Borggrefe and Neuhoff (2011) and von Roon and Wagner (2009) comment on the important role of sequential short-term electricity markets due to a strongly increasing share of renewable energies in Germany. In addition, Knaut and Obermüller (2016) and Ito and Reguant (2016) investigate the optimal strategy choices of renewable producers in sequential markets. The authors find incentives to withhold production capacity in the first market which may cause systematic price premiums in subsequent market stages. In contrast to their theory, Mezzetti et al. (2007) suggest a lowballing effect that may lead to a comparably lower price in the first stage market.

Supporting the findings of Knaut and Paschmann (2017), the idea of high price volatility due to restricted participation has also been studied in Allen and Gale (1994). Furthermore, in Polemarchakis and Siconolfi (1997) the authors point out that limits to market participation may result in incomplete markets and consequently competitive equilibria may not exist. Finally, restricted market participation may lead to limited arbitrage (Hens et al., 2006). We aim at contributing to the existing literature by developing a strategic approach to analyze the underlying drivers of restricted participation in real-world electricity markets.

3. Identifying the Drivers of Restricted Participation

Electricity markets are most commonly organized in a sequential order. Closer to physical delivery the contract duration tends to decrease and the respective markets are cleared in rapid succession. Against this backdrop, Figure 1 depicts the sequential market design for the wholesale electricity markets in Germany [2].

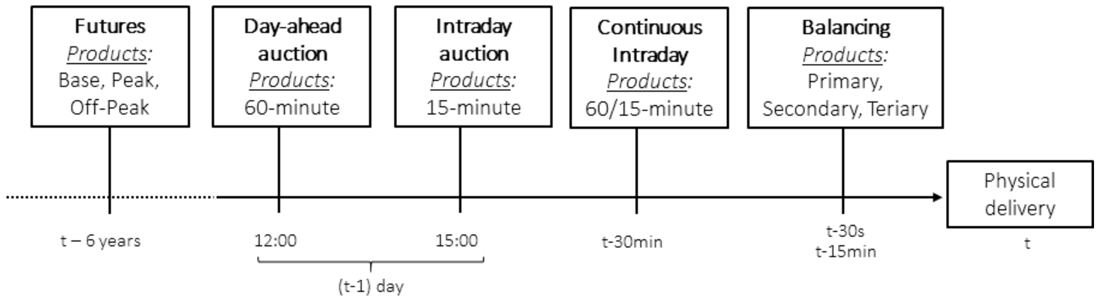

Figure 1: Sequence of trading in wholesale markets

In this paper, we focus on the market interaction between the German day-ahead and intraday auction. Following Knaut and Paschmann (2017), trade in the intraday auction mainly stems from quarter-hourly deviations of the residual load from the respective hourly means. Here residual load is defined as the difference between the overall system load and the electricity generation from renewable power plants. Due to the rapid succession of both auctions, the impact of forecast errors on the trade volumes is rather negligible. There is no informational update between both market stages. According to Knaut and Paschmann (2017), the gradient of the intraday auction supply curve furthermore steeply increases compared to the respective day-ahead merit order due to restricted participation. As a consequence, quarter-hourly intraday auction prices are much more volatile and welfare losses arise[3].

We consider the following four possible reasons for restricted participation in the intraday auction:

i) **Inertia as the state of not knowing**: Market participants may be used to dispatch their power plants on an hourly level according to the day-ahead auction. It is plausible that they may not directly adjust their trading behavior to newly emerging markets such as the intraday auction.

ii) **Costs of market entry**: There may be additional costs for market agents to participate in a new market with a different contract design. This may, e.g., be due to market entry fees or a lack of a respective trading department that enables trading of quarter-hourly products. Furthermore, a lack of aggregation with respect to smaller generation units may be identified.

[2]For more details see Knaut and Paschmann (2017).

[3]This is especially relevant as the increasing share of renewable electricity generation goes hand in hand with an augmented importance of sub-hourly trading opportunities.

iii) **Inflexibility of power plants**: Power plant operators may not be able to adjust their production schedule on a sub-hourly level. This may be due to technical constraints or due to high costs for starting up additional capacities. Especially base load generation units such as nuclear or lignite power plants can be regarded as being less flexible.

iv) **Cross-border trade**: So far, trade of 15-minute products only takes place on a national level. Thereby, only German generation units participate in the market. In contrast, the day-ahead auction is characterized by implicit market coupling across several European countries. Obviously this leads to restricted participation in the market for quarter-hourly products compared to the day-ahead auction.

We empirically analyze the development of the day-ahead and intraday auction price relations over time in order to comment on the role of inertia (Appendix.1). We find an indication that effects related to restricted participation do not fade out. Rather to the contrary, they may be characterized being persistent. In this article, we therefore focus on the latter three hypothetical drivers and evaluate which of them may be a valid explanatory approach for restricted participation in the German intraday auction. First, we shed light on the costs of market entry. We compare fees that arise from trading on the exchange and profits for exemplary generation technologies that may be gained by extending trading activities to the intraday auction. Second, we introduce a modeling framework to simulate the interaction of hourly and quarter-hourly electricity markets which is able to account for the inflexibility of power plants as well as the role of cross-border trade. Based on the model framework, we disentangle both possible drivers of restricted participation iii) and iv).

4. Costs of market entry

In a first step, we provide insights on the benefits and costs for participants entering the intraday auction. We therefore focus on simulating the additional monetary benefits that would result from extending trading activities from solely participating in the day-ahead auction to trading in the intraday auction as well and put the respective results into context with trading fees. We consider two exemplary generation units which are a flexible combined cycle gas turbine (CCGT) and a rather inflexible lignite-fired power plant. In order to conduct profitability analyses for both types of power plants using historical price data, we use a mixed integer program[4]. To comment on the additional revenue potential when entering the intraday auction, we compare a scenario in which the power plant operator only participates in the day-ahead auction and a case in which trade in the intraday auction is allowed as well. We implement sequential trading decisions. That

[4]The model is presented in detail in Appendix.3

is to say, the power plant operator first decides on the hourly day-ahead supply under perfect foresight with respect to hourly prices. In a next step, the quarter-hourly schedule is optimized as a deviation from the previously settled hourly trade quantities based on quarter-hourly prices. We assume that decision makers target to maximize their profits. Furthermore, we consider ramping and start-up constraints as well as part-load losses. Additionally, we account for transaction fees on the power exchange[5]. The methodology applied is based on comparable approaches that have most commonly been applied in the existing literature[6] (see, e.g., Frangioni et al. (2009), Ostrowski et al. (2012) and Richter et al. (2016)). Details on the respective parameters assumed are presented in Table 1. We use exogenous day-ahead and intraday auction prices based on historical data from 2015 (EPEX SPOT SE, 2017b).

	Min load [%]	Max ramp rate [%/15Min]	Start-up/Shut-down rate [%/15Min]	Efficiency full-load/part-load [%]	Fuel Price (incl CO_2) €/MWh_{th}
CCGT (70 MW)	20	100	100/100	54/25	19.37
Lignite (300 MW)	50	37.5	12.5/12.5	30/25	3.42

Table 1: Assumptions asset optimization

In order to compare our simulation results with actual costs related to market entry, we use data that is provided by the exchange (EPEX SPOT SE, 2016). The respective costs are summarized in Table 2. The actual costs of market entry for the day-ahead and intraday auction comprise a one-time as well as yearly fees.

	Initial payment	Yearly fee
Day-ahead auction	25,000 €	10,000 €/a
Intraday auction	7,000 €	5,000 €/a

Table 2: Costs of market entry for the day-ahead and intraday auction

Our simulation results are presented in Table 3. We depict yearly profits achieved from trading activities in the day-ahead and intraday auction for both types of power plants considered. As we regard trading decisions being sequential and independent, the overall profit from solely participating in the day-ahead auction equals the values listed in the column *Day-ahead Profit*.

According to the second scenario considered, participating in the intraday auction yields additional profits that are depicted in the column *Additional Intraday Auction Profit*. Based on the simplified model calculations, additional revenues that may be gained by both types of power plants in the intraday auction

[5]Based on actual values market participants are charged for on the exchange (EPEX SPOT SE), these are 0.04 €/MWh for the day-ahead auction and 0.07 €/MWh for the intraday auction.

[6]The methodological approach is furthermore similar to Section 5.1

	Day-ahead Trades TWh	Day-ahead Profit Mio. €	Intraday Auction Trades TWh	Additional Intraday Auction Profit Mio. €
CCGT	0.19	1.5 (7.9 €/MWh)	0.04	0.23 (5.7 €/MWh)
Lignite	2.5	54.1 (21.6 €/MWh)	0.05	0.3 (6 €/MWh)

Table 3: Model results

exceed the respective costs of market entry many times over. For example, a lignite power plant could earn an additional yearly profit of EUR 300,000 compared to an initial payment of EUR 7,000 and a yearly fee of EUR 5,000. However, we are well aware that besides fees for market entry additional costs may be relevant. These may, for example, refer to implementing a new trading department or paying wages of traders. As these cost components are difficult to quantify, we do not consider these costs explicitly within this paper. Yet, our results provide an indication that costs of market entry may not hinder participation in the intraday auction because there exist economic incentives to participate in the intraday auction.

5. Fundamental Analysis

We choose a fundamental modeling approach in order to simulate price relations under different restrictions referring to technical constraints and cross-border trade. In the following, we briefly outline the main characteristics of the chosen modeling approach.

5.1. Modeling Approach

The modeling approach adopted within this paper extends the electricity system optimization model DIMENSION which has been developed at the Institute of Energy Economics (EWI) at the University of Cologne (Richter, 2011) and which has been applied in numerous studies (see, e.g., Jägemann (2014), Bertsch et al. (2015) and Knaut et al. (2016)). In general, the model so far allows to simulate the hourly dispatch within the internal European electricity market. In order to address the research issues in question, we extend the model to account for a quarter-hourly temporal resolution. In more detail, we mimic the interaction of two simultaneously settled markets with first hourly and second quarter-hourly products. The objective function of the model aims at satisfying the demand at minimum total system costs where the short-term marginal costs can be interpreted as a proxy for the electricity price. The model is implemented as a linear program (LP) in GAMS. We focus on simulating the quarter-hourly dispatch in 2015 in order to compare our results with historical observations.

In the following, we first depict and explain the most relevant model characteristics as well as basic equations and constraints before we then analyze the modeling results. In Section Appendix.6 the overall model is presented in a condensed way with focus on the formalization. Table 4, Table 5 and Table 6 give an overview on the notation applied.

Model Sets

Abbreviation	Description
a ∈ A	Technologies
s ∈ S; S ⊂ A	Storage technologies
c, c_1 ∈ C	Market regions
c', c'_1 ∈ C'; C' ⊂ C	Market regions with cross-border trade on a 15-minute level
q ∈ Q	Quarter-hourly time intervals
h ∈ H	Hourly time intervals
h_q ∈ H	Set of hours that belong to a specific quarter-hourly time interval

Table 4: Sets

Model parameters

Abbreviation	Dimension	Description
ac_a	[€/MWh$_{el}$]	Attrition costs for ramping
$\mathrm{av}_{q,a,c}$	[%]	Availability
$\mathrm{d}_{q,c}$	[MW]	Total demand in 15-minute resolution to be satisfied
ef_a	[t/MWh$_{th}$]	Emissions per fuel consumption
fu_a	[€/MWh$_{th}$]	Fuel price (full load)
fu_a^{ml}	[€/MWh$_{th}$]	Fuel price (min load)
cp	[€/t]	CO_2 emission price
$\mathrm{in}_{a,c}$	[MW]	Installed capacity
ml_a	[%]	Minimum part load level
rr_a	[%]	Maximum ramp rate
st_a	[h]	Start-up time from cold start
η_a	[%]	Net efficiency (generation)

Table 5: Parameters of the electricity system optimization model

Model variables

Abbreviation	Dimension	Description
$\mathrm{hD}_{h,c}$	[MW]	Trade quantities on an hourly level
$\mathrm{qD}_{q,c}$	[MW]	Trade quantities on a quarter-hourly level
$\mathrm{CU}_{q,a,c}$	[MW]	Capacity that is ramped up within one quarter-hour
$\mathrm{CD}_{q,a,c}$	[MW]	Capacity that is ramped down within one quarter-hour
$\mathrm{CR}_{q,a,c}$	[MW]	Capacity that is ready to operate in each quarter-hour
$\mathrm{hGE}_{h,a,c}$	[MW$_{el}$]	Hourly electricity generation
$\mathrm{qGE}_{q,a',c}$	[MW$_{el}$]	Quarter-hourly electricity generation
hIM_{h,c,c_1}	[MW]	Hourly net imports in c from c_1
qIM_{q,c',c'_1}	[MW]	Quarter-hourly net imports in c' from c'_1
$\mathrm{hST}_{h,s,c}$	[MW]	Hourly consumption in storage operation
$\mathrm{qST}_{q,s,c}$	[MW]	Quarter-hourly consumption in storage operation
TSC	[€]	Total system costs

Table 6: Variables of the electricity system optimization model

5.1.1. *Objective function*

The electricity system optimization program applied is based on cost minimization. In more detail, total system costs (TSC) comprise the variable costs of electricity generation ($Costs^{var}$), additional costs for part-load operation ($Costs^{part-load}$), start-up costs ($Costs^{start}$) and ramping costs ($Costs^{ramping}$).

$$TSC = \sum_{c \in C} \sum_{a \in A} \sum_{q \in Q} \left[Costs_{q,a,c}^{var} + Costs_{q,a,c}^{part-load} + Costs_{q,a,c}^{start} + Costs_{q,a,c}^{ramping} \right] \tag{1}$$

First, the net electricity generation that stems from dispatching on an hourly and quarter-hourly level is multiplied with fuel as well as CO_2 emission prices what yields the variable costs of electricity generation ($Costs^{var}$) (2).

$$\begin{aligned} Costs_{q,a,c}^{var} &= \Big(\sum_{h_q \in H} hGE_{h_q,a,c} + qGE_{q,a,c}\Big) \cdot \Big(\frac{fu_a}{\eta_a}\Big) \\ &\quad + \Big(\sum_{h_q \in H} hGE_{h_q,a,c} + qGE_{q,a,c}\Big) \cdot \Big(\frac{cp \cdot ef_a}{\eta_a}\Big) \end{aligned} \tag{2}$$

Depending on the configuration, part-load losses ($Costs^{part-load}$) may be considered (3). They comprise linearized losses depending on the difference between the fuel costs at full load and minimal load and the share of the overall generating capacity that is operated below the totally available generation capacity.

$$Costs_{q,a,c}^{part-load} = \Big(CR_{q,a,c} - \sum_{h_q \in H} hGE_{h_q,a,c} - qGE_{q,a,c}\Big) \cdot \Big(\frac{fu_a^{ml} - fu_a}{\eta_a}\Big) \cdot \Big(\frac{ml_a}{1 - ml_a}\Big) \tag{3}$$

Furthermore, we include start-up costs ($Costs^{start}$). Based on expert opinions gained from industrial project partners, we link start-up processes to a doubling in fuel consumption (4). We are aware that this is a simplifying linear approach not exactly reflecting the complexity of real-world start-up processes. Nonetheless, we are thereby sufficiently capable to account for start-up costs within the analyses.

$$Costs_{q,a,c}^{start} = CU_{q,a,c} \cdot \Big(\frac{fu_a}{\eta_a}\Big) \tag{4}$$

Finally, we consider ramping costs ($Costs^{ramping}$) that reflect increasing attrition if the electricity generation deviates from the respective value in the previous period and stems from wear and tear of technical components (5).

$$Costs^{ramping}_{q,a,c} = (CU_{q,a,c} + CD_{q,a,c}) \cdot ac_a \tag{5}$$

5.1.2. Regional coverage and equilibrium constraints

We consider Germany as well as its neighboring countries in order to reduce the computational complexity[7]. The availability of processing cross-border trade is limited by exogenous historical net transfer capacities (NTC) and we account for the respective average grid losses.

Each market area is characterized by power balance conditions reflecting that national demand plus the demand of storage units equals the intra-zonal electricity generation plus net imports in each time step at equilibrium. To derive the national demand ($d_{q,c}$), we use historical load data from 2015 that we extracted from the ENTSO-E transparency platform (ENTSO-E, 2017) and apply the respective load structure to the overall electricity demand in 2015. Since the data does not provide a quarter-hourly temporal resolution for all countries, we interpolate the respective hourly values where necessary. As we furthermore target to mimic the interaction of two simultaneously settled markets where the market with increased product granularity is characterized by restricted participation, we use the following three equilibrium conditions.

$$hD_{h_q,c} + qD_{q,c} = d_{q,c} \quad \forall\, q, c \tag{6}$$

$$\sum_{a \in A} hGE_{h,a,c} + \sum_{c_1 \in C} hIM_{h,c,c_1} - \sum_{s \in S} hST_{h,s,c} = hD_{h,c} \quad \forall\, h, c \tag{7}$$

$$\sum_{a \in A} qGE_{q,a,c} + \sum_{c_1' \in C'} qIM_{q,c,c_1'} - \sum_{s \in S} qST_{q,s,c} = qD_{q,c} \quad \forall\, q, c \tag{8}$$

Equation (6) determines that the overall inelastic demand on a quarter-hourly level $d_{q,c}$ may be supplied by hourly dispatched as well as quarter-hourly dispatched generation units. The hourly supply (hGE) is a positive rational number, whereas the quarter-hourly supply (qGE) may be negative as well which accounts for negative adjustments compared to the hourly supply schedule. At the same time, all generation units have to remain net suppliers. Finally, the quarter-hourly decision variables are limited by constraints that refer to restricted participation and will be explained in more detail below.

[7] The neighboring countries comprise Austria, Belgium, the Czech Republic, Denmark, France, the Netherlands, Poland and Switzerland.

5.1.3. Generation units

Different types of power plants are grouped into vintage classes. We consider conventional, nuclear, thermal and storage generation units as well as renewable power plants. The renewables are essentially subdivided into generation units based on wind power (onshore and offshore), solar power, hydro power and biomass. At the same time, we distinguish whether generation units are combined heat and power plants (chp) and we include a condition reflecting that the German heat demand in the domestic as well as in the industrial sector has to be supplied by all German chp power plants. As this is not the focus in this paper, further insights can be found in Richter (2011) and Jägemann (2014).

The installed capacities of each type of generation unit are mainly based on historical values and we present the resulting generation capacity in 2015 in Table 7.

Type	Gross Capacity [GW]
Hard Coal	25.41
Lignite	19.94
Natural Gas	31.37
Oil	3.92
Nuclear	10.73
Pumped Storage	6.49
Run of River / Seasonal Storage	5.16
Wind	42.60
Wind onshore	39.32
Wind offshore	3.28
Photovoltaics	38.36
Biomass	7.29
Others	1.60

Table 7: Installed capacity in 2015

We use data on the average power plant availability in order to limit the maximum electricity generation by each type of generation unit. The net electricity generation which results from hourly and quarter-hourly dispatch may not exceed the total installed capacity multiplied with the respective availability (9).

$$\sum_{h_q \in H} hGE_{h_q,a,c} + qGE_{q,a,c} \leq av_{q,a,c} \cdot in_{a,c} \quad \forall\, q, a, c \tag{9}$$

At the same time, the electricity generation, if present, has to exceed the minimum load (10).

$$\sum_{h_q \in H} hGE_{h_q,a,c} + qGE_{q,a,c} \geq ml_a \cdot CR_{q,a,c} \quad \forall\, q, a, c \tag{10}$$

The electricity generation from wind and solar power and the respective feed-in structure is fixed to historical values from 2015[8] provided by the ENTSO-E and EEX transparency platforms (ENTSO-E (2017)

[8]In Germany these were approx. $79TWh$ electricity generation from wind and $35TWh$ from photovoltaic power plants.

, EEX (2017)).

Analyzing the short-term power market flexibility in Germany, storage technologies play a crucial role. Within the model, such technologies especially include pump and hydro storage generation units. The respective plants are mainly characterized by storage level restrictions, turbine as well as pump capacity, exogeeous injections as well as withdrawals and efficiency parameters. We determine an arbitrary target value for the storage value implying that the storage level at the beginning of the optimization period shall equal the respective one in the last period under consideration. Besides, we consider some flexibility potential based on demand-side management. Here demand-side management includes various sources such as industrial processes (e.g., aluminium-electrolysis and cement mills), heating, aeration and ventilation in the service, municipal and domestic sector and electric vehicle flexibility potentials. We determine a specific demand-side management potential and the overall electricity demand of the respective processes has to be balanced along the modeling period.

5.1.4. Technical Constraints

Three main pillars referring to technical constraints of power plants are considered. These include ramping constraints, part-load losses and start-up restrictions.

First, ramping in both directions is restricted by maximum ramp rates that have been extracted from various projects in collaboration with industrial partners. The respective data is depicted in Table .18 in Appendix.4. The available generation capacity in each time step depends on the available capacity in the period before as well as the capacity that has been ramped up or down. We implement the equations listed in (11).

$$\begin{aligned} CR_{q,a,c} = CR_{q-1,a,c} + CU_{q-1,a,c} - CD_{q-1,a,c} \quad & \forall\, q,a,c \\ CU_{q,a,c} \leq rr_a \cdot (in_{a,c} - CR_{q,a,c}) \quad & \forall\, q,a,c \\ CD_{q,a,c} \leq rr_a \cdot (CR_{q,a,c}) \quad & \forall\, q,a,c \end{aligned} \tag{11}$$

Finally, start-up constraints are transferred into additional limits for the capacity that may be ramped up according to (12).

$$CU_{q,a,c} \leq \frac{in_{a,c} - CR_{q,a,c}}{st_a} \quad \forall\, q,a,c \tag{12}$$

All of these technical constraints are linked to additional costs that are included in the objective function.

5.1.5. Electricity market prices

In this paper, we are especially interested in price relations. Therefore, we derive prices based on the fundamental modeling results. Being a linear program, we are able to interpret the marginals on the power balance constraints as the marginal costs of electricity generation. The marginal on Equation (7) may thus be regarded as reflecting the electricity price in the market with hourly products, whereas we consider the marginal on (8) allowing to draw conclusions on the respective quarter-hourly electricity prices. In reality price mark-ups above marginal costs may also be observable but as we are not interested in absolute price levels but in the comparison of relative price relations, the application of marginals is assumed to be suitable.

5.2. Results

We address the fundamental impact of technical constraints and a lack of cross-border trade on electricity prices by gradually implementing or relaxing additional constraints in the model in order to analyze the respective impact on price relations. We compare the specific results based on descriptive key figures. These, inter alia, include the minimum as well as maximum values, the standard deviation and percentile thresholds. We refer to prices p_h reflecting the marginals on the hourly power balance constraint and to prices p_q as marginals on the respective quarter-hourly constraint.

5.2.1. Reference Case and Model Validation

We intend to link our model results to the real-world market outcome by analyzing a Reference Scenario S_{ref} in which we mimic the actual day-ahead and intraday market interaction for 2015. Such reference case is a fundamental model run including all technical constraints that refer to power plant inflexibility as outlined above. Furthermore, we assume that there is no quarter-hourly market coupling. We expect this setup to represent the current status of the electricity markets in Germany and the neighboring countries.

In order to evaluate the model validity, we compare prices derived from the fundamental model results and real price data for 2015. Based on the comparison in Table 8, we suggest that the model is able to reproduce the average price level in 2015 well, but rather fails in reproducing comparably high and low price levels. This deficiency of linear fundamental models is well known and is the result of numerous model assumptions. First, the aggregation of generation units into vintage classes causes a lack of accuracy regarding the actual diversity of power plants. As a result, we expect the prices simulated in the model framework not to represent the actual variability of electricity prices. As a second aspect, the assumptions of perfect foresight does not comply with the real-world problem. We therefore expect that our results may be downward-biased with regard to restricted participation since our assumptions can be regarded being rather optimistic as far as the participation in markets with sub-hourly contract duration is concerned.

However, as we do not aim at forecasting as well as interpreting absolute price levels but rather intend to derive conclusions on the fundamental impact of restricted participation on price relations, our simulation approach still appears suitable. Nonetheless, we are well aware of the limited generalizability of our results regarding actual electricity prices.

	S_{ref} [€/MWh]	Historical [€/MWh]
Mean (p_q)	30.25	31.66
Mean (p_h)	30.25	31.63
Min (p_q)	8.56	-164.48
Min (p_h)	10.49	-79.94
10% Percentile (p_q)	23.59	14.52
10% Percentile (p_h)	23.47	16.26
90% Percentile (p_h)	36.89	47.44
90% Percentile (p_q)	37.52	49.64
Max (p_q)	83.41	464.37
Max (p_h)	52.82	99.77
Mean absolute price difference (p_h - p_q)	0.87	6.57
Standard deviation price difference (p_h - p_q)	1.60	9.28

Table 8: Summary statistics for the reference case and historical prices

According to Knaut and Paschmann (2017), restricted participation causes a distinct price pattern that is characterized by quarter-hourly prices fluctuating around the respective hourly ones. The sub-hourly price volatility is much higher than the hourly one. The model applied in this article is basically able to reproduce such characteristic price pattern as shown in Figure 2. In order to characterize the extent of the quarter-hourly price deviations from hourly means, we use two indicators for sub-hourly price volatility in the following. These are *mean absolute price difference (p_h - p_q)* and *standard deviation price difference (p_h - p_q)*. Albeit lower levels of both indicators in our model runs compared to historical data (by up to factor seven) signify less pronounced price fluctuations as shown in Table 8, we are yet confident that relative comparisons of different scenarios yield meaningful indicators for our further analysis.

5.2.2. The role of power plant flexibility

We are first interested in whether power plant inflexibility may serve as a sufficient explanatory approach for restricted participation in the intraday auction. Whereas, as a reflection of reality, all types of model restrictions related to technical constraints of generation units are considered in the Reference Scenario S_{ref}, we now aim at analyzing whether neglecting power plant flexibility constraints may trigger restricted participation and the resulting characteristic price pattern to disappear. Thus, we set up the 'No-Ramping Scenario' (S_{noramp}) without technical constraints. Again cross-border trade on a quarter-hourly level is not

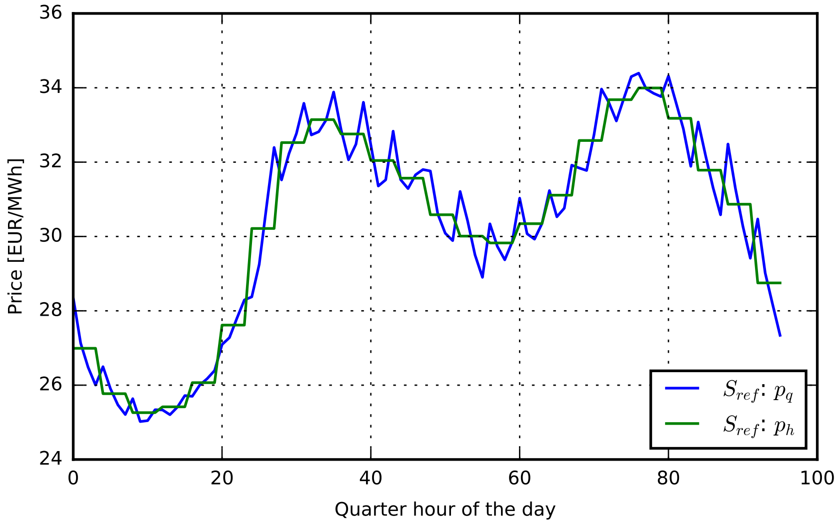

Figure 2: Daily pattern of average hourly and quarter-hourly price levels in the reference model run

permitted in both scenarios. We choose a comparative illustration and depict the fundamental model results for both scenarios in Figure 3. In the graph we present average price relations in each quarter-hour of the day along the modeling period for both model runs. Further details including descriptive statistics on the hourly as well as quarter-hourly price levels can be found in Table .23 of Section Appendix.8.

In order to comment on whether the quarter-hourly price volatility observed in historical data may stem from technical constraints, we again compare the two target figures *mean absolute price difference* and *standard deviation of price differences* between both scenarios (Table 9).

Target Figure	S_{noramp} [€/MWh]	S_{ref} [€/MWh]
Mean absolute price difference (p_h - p_q)	0.51	0.87
Standard deviation price difference (p_h - p_q)	0.99	1.6

Table 9: Evaluation of price differences: The role of power plant flexibility

Our modeling results suggest that neglecting technical constraints causes a decreasing price volatility in the market with quarter-hourly contract duration[9]. More precisely, we find that the standard deviation of price differences decreases by 60% if we do not account for technical constraints. However, we still observe that the 15-minute electricity price proxies are highly fluctuating around the respective hourly ones. The characteristic price pattern that we trace back to restricted participation is still applicable. Thus, we find an indication that additional influencing factors may trigger the pattern observed. In the next section we

[9]We analyze the individual impact of all types of technical constraints considered in more detail in Section Appendix.7.

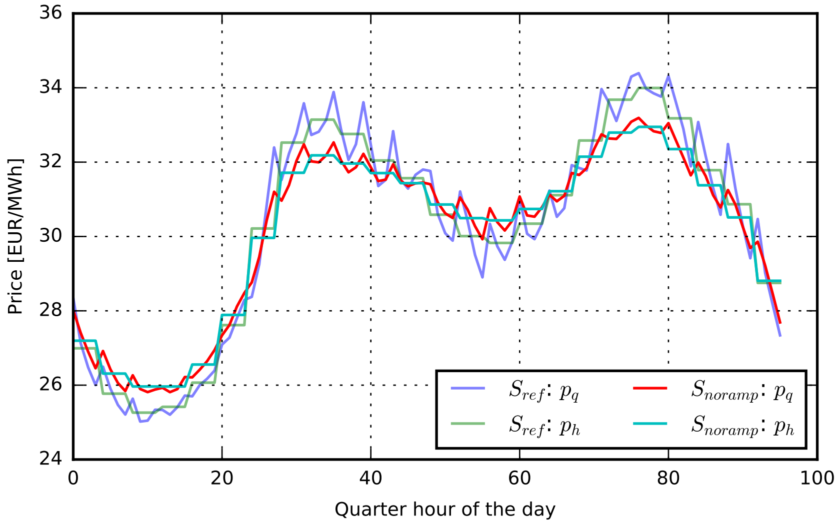

Figure 3: Daily pattern of average hourly and quarter-hourly price levels in the reference model run (S_{ref}) and the model run without ramping restrictions (S_{noramp})

hence aim at assessing the relative impact of power plant inflexibility in comparison to a lack of market coupling on a quarter-hourly level.

5.2.3. The role of market coupling

We compare fundamental model results for both a scenario without any cross-border trade on a sub-hourly level and a scenario with full market coupling. At the same time, we include all technical constraints referring to power plant flexibility. Simply put, we compare the Reference Case (S_{ref}) with a scenario in which quarter-hourly cross-border trade is permitted (S_{fullcb}). We use target figures analogous to the previous sections. The respective results are illustrated in Figure 4.

Target Figure	S_{ref} [€/MWh]	S_{fullcb} [€/MWh]
Mean absolute price difference (p_h - p_q)	0.87	0.24
Standard deviation price difference (p_h - p_q)	1.6	0.55

Table 10: Evaluation of price differences: The role of market coupling

The permission of cross-border trade on a 15-minute level clearly induces a convergence of hourly and 15-minute prices which can be traced back to additional market participation. Furthermore, the Reference Case's price pattern in which quarter-hourly prices are fluctuating around the respective hourly ones tends to disappear if quarter-hourly market coupling is implemented. Additionally, according to Table 10, the mean absolute price difference as a proxy for restricted participation and price volatility decreases by a

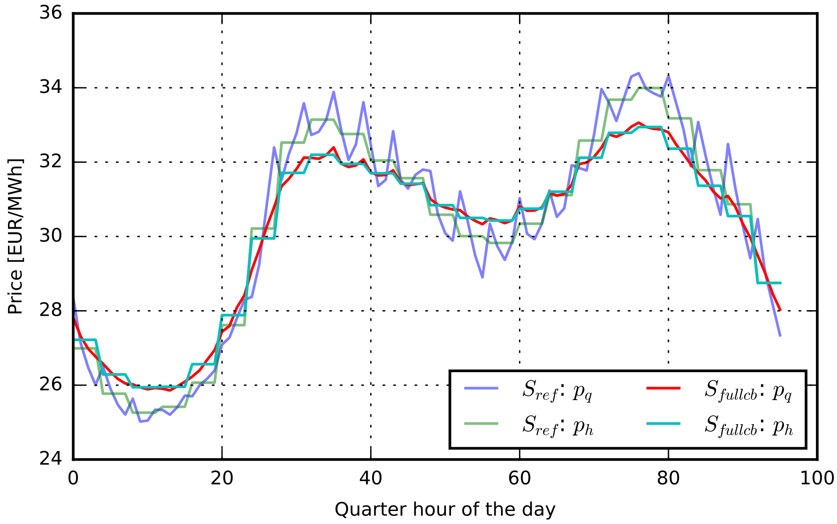

Figure 4: Daily pattern of average hourly and quarter-hourly price levels in the reference model run (S_{ref}) and model run with cross border trade on a quarter-hourly level (S_{fullcb})

factor close to four. All in all, we find an indication that the lack of sub-hourly market coupling is the main driver of restricted participation in the market with quarter-hourly contracts. We furthermore derive the welfare impact of implementing sub-hourly market coupling based on our modeling results. The total system costs (1) decrease by EUR 55 million if 15-minute cross-border trade is permitted what is well in line with Knaut and Paschmann (2017).

6. Conclusion

In this paper, we analyze three plausible drivers of restricted participation in the German intraday auction with 15-minute contract duration in detail. As the overall efficiency of sequential market designs decreases with limited market participation, it is crucial to identify the underlying drivers in order to take countermeasures.

First, we are interested in whether costs of market entry may represent an economic driver of not participating in the intraday auction while, in contrast, participating in the day-ahead auction. Based on economic calculations for different types of generation units, we find an indication that this may not be consistent with the individual economic decision rationales.

Second, we apply a fundamental electricity market model in order to evaluate the impact of both power plant inflexibility as well as a lack of sub-hourly market coupling on the quarter-hourly price volatility. Our results indicate that the lack of market coupling on a quarter-hourly level constitutes the most relevant driver of restricted participation in the German intraday auction. Based on our results, we finally suggest that additional market coupling may cause the 15-minute price volatility to decrease by a factor close to four.

Our results may serve as a basis for deriving countermeasures in order to reduce inefficiencies that result from restricted participation in electricity markets with sub-hourly products. It may be beneficial for policy makers to urge the implementation of quarter-hourly market coupling across the internal European electricity market as addressed by the XBID project. At the same time, understanding the most relevant drivers of restricted participation in the intraday auction may help power plant operators to forecast the impact of policy measures such as introducing sub-hourly market coupling on the resulting prices. This is crucial in order to evaluate long-term business strategies. Finally, our methodological approach points out that energy system models may benefit from a quarter-hourly temporal resolution especially as far as modeling the investment decisions of flexible generation units is concerned. The model allows to simulate sequential market dynamics with a differing product granularity and different types of market coupling.

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Appendices

Appendix.1. Empirical Analysis

In order to assess the impact of introducing a new trading opportunity on the resulting price relations, we empirically analyze the development of the respective market dynamics over time. We thereby get an indication for the maturity of the market. The empirical results help shedding light on the role of inertia and the state of not knowing of market participants. Our estimation approach heavily builds on the approach applied in Knaut and Paschmann (2017). In the following, we first depict the data used. We then present our estimation procedure and evaluate the respective results.

Appendix.1.1. Data

Our empirical analysis is based on data from January 1, 2015 until April 30, 2017. We conduct the empirical estimation on a quarter-hourly level. Table .11 gives an overview on all relevant data included. We furthermore provide a brief explanation regarding each parameter. Supplementary, the respective descriptive statistics are presented in Table .12.

We include general price data for the day-ahead and intraday auction that is provided by the European Power Exchange (EPEX SPOT SE, 2017b). As regards the main explanatory variables, we first take the day-ahead forecasts for the electricity generation from wind and solar power since trade in the spot markets under consideration is based on forecasted values. The respective data is available on the transparency platform of the European Energy Exchange (EEX, 2017). Second, we use the realizations of the actual system load[10]. The respective load values as a proxy for the overall electricity demand[11] are accessible via data provided by the Transmission System Operators (TSOs) on the transparency platform of the European Network of Transmission System Operators for Electricity (ENTSO-E, 2017).

Appendix.1.2. Empirical Estimation

We use Ordinary Least Squares (OLS) regression techniques and apply estimation equation (.1) with the intraday auction price being the dependent variable.

$$\begin{aligned} p_t^{ida} &= \beta_1 \cdot \overline{D^{res}}_t + \beta_2 \cdot (D_t^{res} - \overline{D^{res}}_t) + \nu + \epsilon_t \\ &\text{with } \epsilon_t \sim \; N\,(0, \sigma^2), \end{aligned} \tag{.1}$$

[10]Here we use ex post instead of ex ante values as we find the respective data matching the causal relations under analysis with higher accuracy. The forecasted values available exhibit systematic deviations which are not consistent with the economic rationales of the market participants considered. Therefore, we expect the realizations of the system load to match the actual level of information more accurately.

[11]For more details on load see Schumacher and Hirth (2015).

Symbol	Label	Variable	Measure	Reference
p_t^{ida}	id auction price	Uniform settlement price for a 15-minute product in the German intraday auction	€/MWh	EPEX SPOT SE (2017b)
p_t^{da}	day-ahead price	Hourly German day-ahead auction price	€/MWh	EPEX SPOT SE (2017b)
D_t^{res}; $\overline{D^{res}}_t$	residual demand 15 residual demand 60	Residual demand in a 15-minute period and the respective hourly mean	GW	EEX (2017) , ENTSO-E (2017)
ΔD_t^{res}	residual demand deviation	Difference of the 15-minute residual demand and the respective hourly mean (Forecasts)	GW	EEX (2017) , ENTSO-E (2017)
$Solar_t$; $\overline{Solar}_t$	solar power 15 solar power 60	Day-ahead forecast for the 15-minute solar power and the respective hourly mean (ex-ante value)	GW	EEX (2017)
$Wind_t$; $\overline{Wind}_t$	wind power 15 wind power 60	Day-ahead forecast for the 15-minute wind power and the respective hourly mean (ex-ante value)	GW	EEX (2017)
D_t; $\overline{D}_t$	load 15; load 60	Realization of the 15-minute load and the respective hourly mean	GW	ENTSO-E (2017)

Table .11: List of variables and references

Variable	N	Mean	Std.Dev.	Min	25%	Median	75%	Max
id auction price	81,663	31.49	15.89	-164.48	22.62	30.57	39.92	464.37
day-ahead price	81,663	31.42	14.12	-130.09	23.94	30.29	38.11	163.52
residual demand 15	81,663	41.67	11.09	0.95	34.36	41.59	49.58	73.00
residual demand 60	81,663	41.67	11.06	1.86	34.39	41.60	49.56	72.39
residual demand deviation	81,663	0.00	0.81	-12.27	-0.39	0.00	0.38	8.82
solar power 15	81,663	3.92	6.06	0.00	0.00	0.07	6.19	27.18
wind power 15	81,663	9.58	7.47	0.30	3.83	7.43	13.23	39.56
load 15	81,663	55.17	10.00	25.04	46.81	54.85	64.09	78.09

Table .12: Descriptive Statistics (Units according to .11, N refers to the number of observations)

Here the intraday auction price is modeled as a deviation from the respective day-ahead price that has been settled before. Simply put, we use a reference price approach in which the increasing product granularity induces imbalances that cause new market equilibria in the second market stage what is the intraday auction. However, since we aim at comparing the estimates that reflect the impact of trade quantities on prices in the day-ahead as well as the intraday auction, we replace the day-ahead price with the hourly residual demand ($\overline{D^{res}}$). We base our procedure on the fact that the hourly residual demand is the main driver of trade in the day-ahead auction. At the same time, we are well aware that not directly including the day-ahead price causes a minor loss of explanatory power.

According to Section 3, we additionally include the deviation of the quarter-hourly residual load from its hourly mean ($D_t^{res} - \overline{D^{res}}_t$) as the main driver of additional trade needs on a quarter-hourly level in the intraday auction. We furthermore estimate a constant intercept in order to be able to interpret the R^2. Finally, we use robust standard errors to account for heteroscedasticity.

Based on both an Augmented Dickey Fuller as well as a Phillips-Perron test (see Appendix.2), we reject the hypothesis of non-stationary processes. We additionally expect our estimation approach not to be biased by endogeneity since our explanatory variables are based on forecasted values that have been generated before the day-ahead market settlement. Thus, the market outcome has no direct impact on the variables used. Additionally, the solar and wind power depend on weather conditions that are exogenously given. Overall, we hence assume a unidirectional impact of the explanatory variables on the dependent variable. It is worth considering issues related to omitted variables. In Knaut and Paschmann (2017) the authors show that forecast errors do not have significant impact on the intraday auction price as they tend to reveal closer to physical delivery and are far more likely to be balanced within continuous intraday trade. Furthermore, we got several expert opinions of energy trading companies giving evidence that there is no informational update between both market settlements. Since cross-border trade is furthermore not permitted within the intraday auction, imports and exports that are typical variables to map the price formation are not worth considering.

We apply two OLS specifications (OLS (1) and OLS (2)). Whereas in OLS (1) we aim at measuring the average increase of the gradient of the supply curve in the intraday auction compared to the day ahead auction, OLS (2) focuses on structural changes over time. In more detail, in OLS (2) we separately estimate the coefficients for the years 2015, 2016 and 2017 by interacting the explanatory variables with the respective time dummies. Thereby, we are able to comment on effects related to the introduction of the intraday auction and inertia.

	Dependent variable: id auction price ($p^{ida}_{q,t}$)			
Explanatory variable	OLS (1)	OLS (2)		
residual demand 60 ($D^{res}_{h,t}$)	1.03***			
	(0.005)			
		2015	*2016*	*2017*
		1.03***	0.95***	1.16***
		(0.004)	(0.004)	(0.006)
residual demand deviation (ΔD^{res}_{t})	7.65***			
	(0.08)			
		2015	*2016*	*2017*
		8.75***	6.21***	8.49***
		(0.14)	(0.10)	(0.22)
intercept (ν)	-11.26*** (0.19)	-10.84*** (0.17)		
observations	81,663	81,663		
adj. R^2	0.66	0.70		
F	26,273	11,366		

Notes to Table .13: Robust standard errors in parentheses. * / ** / *** : significant at the 0.05 /0.02 / 0.01 error level respectively. In OLS (2) we interact the explanatory variables with yearly time dummies. We use data from January 2015 until the end of April 2017.

Table .13: Regression estimates for intraday auction price data

In line with Knaut and Paschmann (2017), we identify a significant increase of the gradient of the intraday auction supply curve by a factor higher than seven compared to the respective one in the day-ahead auction. Our estimates exhibit sufficient explanatory power with the R^2 being above 66%. Based on OLS (2), we furthermore infer that the respective relation of the coefficients slightly decreases from factor 8.5 in 2015 to factor 6.5 in 2016. Yet, the impact of restricted participation is again exacerbated in the first four months of 2017 and we identify a factor of 7.3. It has to be taken into account that the findings for 2017 are solely based on four months of observations. It may be worth analyzing a prolonged period in future research. Nonetheless, we find an indication that inertia as the state of not knowing is only a minor driver of restricted participation in the intraday auction. A high difference between the hourly and quarter-hourly gradients is persistent over time. To sum up, our estimation results suggest that effects related to introducing a new trading opportunity and inertia do not trigger the major share of restricted participation in the intraday auction.

Appendix.2. Unit Root Tests

We apply both an Augmented Dickey Fuller test and a Phillips-Perron test for unit roots. The respective test results are displayed in Table .14 (Dickey and Fuller, 1979; Phillips and Perron, 1979). The Phillips-

Perron test uses Newey-West standard errors in order to account for serial correlation. The null hypothesis of both tests is that there is a unit root in the periods of observation. We tested the Akaike Information Criterion (AIC) in order to determine the optimal lag lengths. As the AIC results are ambiguous for the variables considered and tend to indicate using as many lags as tested for, we use the Schwert rule of thumb and consider a leg length of 65 (Schwert, 1989). We prefer making a slight error due to including too many lags since Monte Carlo experiments suggest that this procedure is preferable to including too few lags. In order to give evidence for the robustness of our results, we repeated the tests for different lag lengths. Within the scope of the Augmented Dickey Fuller test, we extend the basic test of a random walk against a stationary autoregressive process by including a drift and a trend term. As far as the listed results are concerned, we decide whether to include a trend or constant by checking the significance of the trend/constant parameters at a 5% significance threshold.

	Augmented Dickey Fuller (Levels)			Philipps-Perron Test (Levels)		
Variable	statistic	p-value	lags	statistic	p-value	lags
id auction price	-18.34	0.00	65	-188.27	0.00	65
day ahead price	-16.32	0.00	65	-24.04	0.00	65
residual demand 60	-12.36	0.00	65	-21.71	0.00	65
residual demand deviation 15	-47.20	0.00	65	-683.70	0.00	65

Table .14: Unit root tests

Appendix.3. Profitability Analysis Model Description

Sets

Abbreviation	Description
q $\in$ Q	Quarter-hourly time intervals
h $\in$ H	Hourly time intervals
$h_q \in$ H	Set of hours that belong to a specific quarter-hourly time interval

Table .15: Sets of the model applied for profitability analyses

Model parameters

Abbreviation	Dimension	Description
η	[%]	Net efficiency (generation)
fu	[€/MWh$_{th}$]	Fuel price incl CO_2 (full load)
fu^{ml}	[€/MWh$_{th}$]	Fuel price incl CO_2 (min load)
in	[MW]	Installed capacity
ml	[%]	Minimum part load level
rr	[%]	Maximum ramp rate
$p_{DA,h}$	[€/MWh$_{el}$]	Day-ahead auction price
$p_{ID,q}$	[€/MWh$_{el}$]	Intraday auction price
st	[h]	Start-up time from cold start

Table .16: Parameters of the model applied for profitability analyses

Model variables

Abbreviation	Dimension	Description
GE$_h$	[MW$_{el}$]	Day-ahead electricity generation
ΔGE$_q$	[MW$_{el}$]	Quarter-hourly production schedule as deviation from day-ahead supply
O$_q$	[MW]	Bool whether plant is in Operation
Start$_q$	[MW]	Bool whether start-up process is initiated
Profit	[€]	Profit of power plant

Table .17: Variables of the model applied for profitability analyses

We apply profit maximization.

$$\begin{aligned}
\underset{GE_h,\Delta GE_q}{\text{maximize}}\, Profit &= \sum_q \big[\big(\sum_{h_q} \frac{1}{4} \cdot Revenue_{DA,h_q}\big) + Revenue_{ID,q} - Costs_{Production,q} - Costs_{Startup,q}\big] \\
&\quad where \\
Revenue_{DA,h} &= GE_h \cdot (p_{DA,h} - 0.04) \\
Revenue_{ID,q} &= \Delta GE_q \cdot \frac{1}{4} \cdot (p_{ID,q} - 0.07) \\
Costs_{Production,q} &= \frac{\sum_{h_q} GE_{h_q} + \Delta GE_q}{\eta} \cdot fu \\
&\quad + (O_q \cdot in - \sum_{h_q} GE_{h_q} - \Delta GE_q) \cdot \frac{fu^{ml} - fu}{\eta} \cdot \frac{ml}{1 - ml} \\
Costs_{Startup,q} &= Start_q \cdot ml \cdot in \cdot \frac{fu}{\eta}
\end{aligned} \tag{.2}$$

The revenue terms include transaction costs which depend on the specific market place. These are actual fees charged on the exchange. Based on expert opinions, we assume start-up procedures to cause doubled fuel costs.

We consider the following constraints:

$$\sum_{h_q} GE_{h_q} + \Delta GE_q \leq in \cdot O_q \quad \forall q \tag{.3}$$

$$\sum_{h_q} GE_{h_q} + \Delta GE_q \geq ml \cdot O_q \quad \forall q \tag{.4}$$

$$\sum_{h_q} GE_{h_q} + \Delta GE_q \geq 0 \quad \forall q \tag{.5}$$

$$\sum_{h_q} GE_{h_q} + \Delta GE_q - \sum_{h_{q-1}} GE_{h_{q-1}} + \Delta GE_{q-1} \leq rr \quad \forall q \tag{.6}$$

$$\sum_{h_{q-1}} GE_{h_{q-1}} + \Delta GE_{q-1} - \sum_{h_q} GE_{h_q} + \Delta GE_q \leq rr \quad \forall q \tag{.7}$$

Putting aside the exact formula, we furthermore implemented that the generation unit may only be in operating mode ($O_q = 1$) if a start-process ($Start_q$=1) has been initiated several period before according to *Start-up time from cold start.*

Appendix.4. Techno-economic parameters

	Net efficiency [%]	Max ramp rate [%/Min]	Availability [%]	Start-up time [h]	Minimum part-load [%]
Coal	37 - 46	0.02-0.033	84	5 - 7	27 -40
Coal (innovative)	50	0.4	84	4	27
Lignite	32 - 43	0.02-0.025	86	10 - 11	35 - 60
Lignite (innovative)	47	0.04-0.05	86	7	30
CCGT	40 - 60	0.05-0.08	86	2 - 3	40 - 70
OCGT	28 - 40	0.1-0.25	86	0.25	40 - 50
Nuclear	33	0.04	92	24	45
Biomass (solid)	30	1	85	1	30

Table .18: Techno-economic parameters for conventional power plants. Note: We consider several vintage classes for each type of generation unit. Depending on the construction year, we thus depict ranges for specific parameters.

Appendix.5. Fuel and CO_2 emission costs

Appendix.6. Model Overview

Minimize

$$TSC = \sum_{c \in C} \sum_{a \in A} \sum_{q \in Q} \left[Costs^{var}_{q,a,c} + Costs^{part-load}_{q,a,c} + Costs^{start}_{q,a,c} + Costs^{ramping}_{q,a,c} \right] \tag{.8}$$

Type	Costs [€/MWh_{th}]
Nuclear	3.5
Lignite	3.5
Oil	27.7
Coal	8.9
Gas	18.4
CO_2 emission price [€/tCO_2]	2015
CO_2	4.8

Table .19: Fuel costs and CO_2 emission costs 2015

with

$$\begin{aligned} Costs^{var}_{q,a,c} = &(\sum_{h_q \in H} hGE_{h_q,a,c} + qGE_{q,a,c}) \cdot (\frac{fu_a}{\eta_a}) \\ &+ (\sum_{h_q \in H} hGE_{h_q,a,c} + qGE_{q,a,c}) \cdot (\frac{cp \cdot ef_a}{\eta_a}) \end{aligned} \tag{.9}$$

$$Costs^{part-load}_{q,a,c} = (CR_{q,a,c} - \sum_{h_q \in H} hGE_{h_q,a,c} - qGE_{q,a,c}) \cdot \frac{fu^{ml}_a - fu_a}{\eta_a} \cdot \frac{ml_a}{1 - ml_a} \tag{.10}$$

$$Costs^{start}_{q,a,c} = CU_{q,a,c} \cdot (\frac{fu_a}{\eta_a}) \tag{.11}$$

$$Costs^{ramping}_{q,a,c} = (CU_{q,a,c} + CD_{q,a,c}) \cdot ac_a \tag{.12}$$

such that

$$hD_{h_q,c} + qD_{q,c} = d_{q,c} \quad \forall\, q, c \tag{.13}$$

$$\sum_{a \in A} hGE_{h,a,c} + \sum_{c_1 \in C} hIM_{h,c,c_1} - \sum_{s \in S} hST_{h,s,c} = hD_{h,c} \quad \forall\, h, c \tag{.14}$$

$$\sum_{a \in A} qGE_{q,a,c} + \sum_{c'_1 \in C'} qIM_{q,c,c'_1} - \sum_{s \in S} qST_{q,s,c} = qD_{q,c} \quad \forall\, q, c \tag{.15}$$

$$\sum_{h_q \in H} hGE_{h_q,a,c} + qGE_{q,a,c} \leq av_{q,a,c} \cdot in_{a,c} \quad \forall\, q, a, c \tag{.16}$$

$$\sum_{h_q \in H} hGE_{h_q,a,c} + qGE_{q,a,c} \geq ml_a \cdot CR_{q,a,c} \quad \forall\, q, a, c \tag{.17}$$

$$CR_{q,a,c} = CR_{q-1,a,c} + CU_{q-1,a,c} - CD_{q-1,a,c} \quad \forall\, q, a, c \tag{.18}$$

$$CU_{q,a,c} \leq rr_a \cdot (in_{a,c} - CR_{q,a,c}) \quad \forall\, q, a, c \tag{.19}$$

$$CD_{q,a,c} \leq rr_a \cdot (CR_{q,a,c}) \quad \forall\, q, a, c \tag{.20}$$

$$CU_{q,a,c} \leq \frac{in_{a,c} - CR_{q,a,c}}{st_a} \quad \forall\, q, a, c \tag{.21}$$

Appendix.7. Details on the impact of individual technical constraints

In the following, we shed light on the individual impact of all types of technical constraints considered. Therefore, we add further model restrictions in a step-wise manner while assuming that cross-border trade on a quarter-hourly level is not permitted. Starting without any constraints referring to ramping and start-up characteristics (S_1), we consider limits to ramp rates in S_2 and compare the respective model results. In the left graph of Figure Appendix.7 we illustrate average price relations in each quarter-hour of the day along the modeling period for both model runs. In the right table we present the respective descriptive statistics on the hourly as well as quarter-hourly price levels. In order to comment on whether the quarter-hourly price volatility observed in historical data may stem from technical constraints, we compare the mean absolute price differences and the standard deviation of price differences as indicators for price volatility between both scenarios.

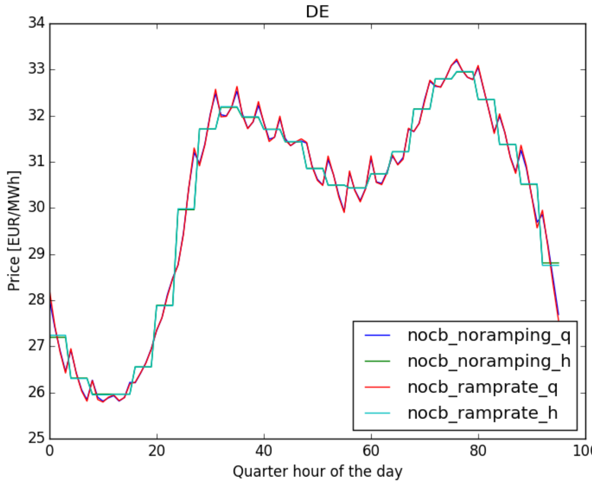

Figure .5: No ramping vs raming rate

	S_{noramp}	S_2
Min	10.3/10.1	10.3/10.1
10%	23.6/24.0	23.7/24.0
Mean	30.1/30.1	30.1/30.1
90%	36.9/36.9	36.9/36.9
Max	44.1/44.1	44.1/44.1
STD	5.9/6.0	5.9/6.0

Table .20: No ramping vs raming rate

Target Figure	S_{noramp}	S_2
Mean absolute price difference (p_h - p_q)	0.51	0.54
Standard deviation price difference (p_h - p_q)	0.99	1.05

Table .21: Evaluation of price differences [€/MWh]

It becomes obvious that power plant inflexibility incorporated by ramp rates only has very little impact on the quarter-hourly price volatility. Comparing the price lines in the graph we find an indication that both scenarios are quite similar with regard to the price volatility simulated. More details are presented in Table .21. Based on the target figures *Mean absolute price difference* and *Standard deviation price difference*, we find that adding ramping constraints only causes a slight increase of the price volatility what means that the average absolute price difference increases by approximately 6%.

In a second step, we aim at analyzing the impact of further technical constraints including part-load losses and start-up constraints. Again we refer to the target figures from above and present the respective modeling results in Table .22. For the sake of simplicity, we focus on the resulting price differences. Again S_2 means the inclusion of ramp rates, whereas in S_3 we additionally consider part-load losses. Finally, S_4 extends the previous model runs having implemented start-up constraints and the related costs.

Target Figure	S_2	S_3	S_4
Mean absolute price difference (p_h - p_q)	0.54	0.61	0.65
Standard deviation price difference (p_h - p_q)	1.05	1.14	1.21

Table .22: Evaluation of price differences [€/MWh]

Again the results suggest a progressively increasing quarter-hourly price volatility. Finally, adding attrition costs resulting from ramping processes, we obtain the Reference Scenario (S_{ref}) which is evaluated in detail within the article. Overall, our modeling results suggest that the most significant change regarding the quarter-hourly price volatility is induced by considering ramping and start-up costs.

Appendix.8. Descriptive Statistics on Model Results

	S_{noramp}	S_{ref}
Min	10.3/10.1	10.5/8.6
10%	23.6/24.0	23.5/23.6
Mean	30.1/30.1	30.3/30.3
90%	36.9/36.9	37.5/36.9
Max	44.1/44.1	52.8/83.4
STD	5.9/6.0	6.2/ 6.4

Table .23: Descriptive statistics on model results (electricity prices [€/MWh]) evaluating the impact of technical constraints

	S_{ref}	S_{fullcb}
Min	10.5/8.6	10.3/10.3
10%	23.5/23.6	23.8/23.8
Mean	30.3/30.3	30.1/30.1
90%	37.5/36.9	36.9/36.9
Max	52.8/83.4	44.1/44.1
STD	6.2/ 6.4	5.9/5.9

Table .24: Descriptive statistics on model results (electricity prices [€/MWh]) evaluating the impact of sub-hourly market coupling