Control Power and Variable Renewables

A Glimpse at German Data

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Abstract – Control power (regulating power, balancing power) is used to quickly restore the supply-demand balance in power systems. Variable renewable energy sources (VRE) such as wind and solar power are often thought to increase the reserve requirement significantly. This paper provides a comprehensive overview of balancing systems in Europe, discusses the role of VRE, and presents empirical market data from Germany. Despite German VRE capacity doubled during the last five years and has surpassed 70% of peak load, contracted control power decreased by 20%, and procurement cost fell by 50%. Today, control power adds only 0.4% to household electricity prices. Nevertheless, we identify several sources of inefficiency in control power markets and imbalance settlement systems and propose a number of policy changes to stimulate the participation of VRE in control provision and to improve the incentives to forecast accurately.

Key Words – Balancing power; Control Power; Variable renewables; Wind power; Solar power; Market design

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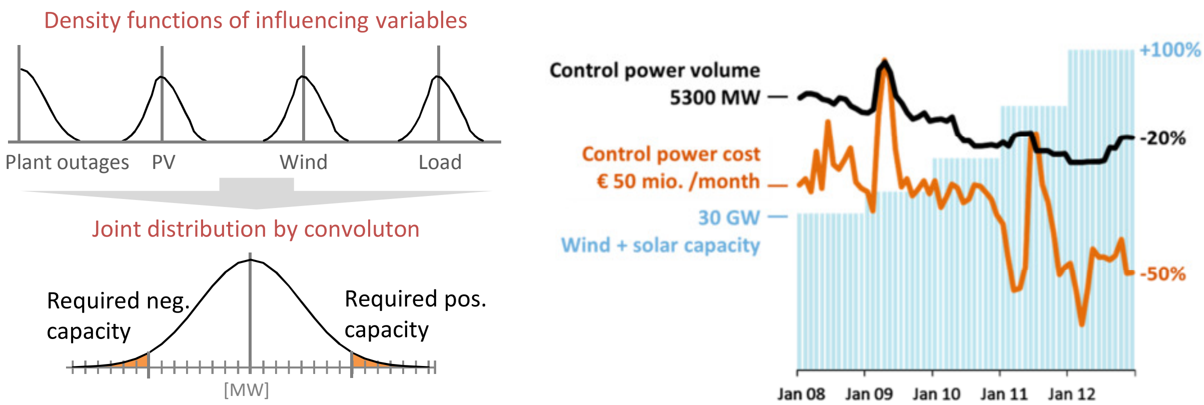

Graphical Abstract – There are many factors that determine the reserve requirement for control (left). Combined wind and solar capacity in Germany doubled between 2008 and 2012 (right). Surprisingly, the capacity of control power that system operators contracted for short-term system balancing decreased by 20% and costs dropped by 50%.

The findings, interpretations, and conclusions expressed herein are those of the authors and do not necessarily reflect the views of Vattenfall or the Potsdam-Institute. Corresponding author: Lion Hirth, Vattenfall GmbH, Chausseestraße 23, 10115 Berlin, lion.hirth@vattenfall.com, +49 30 81824032.

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1. Introduction

In integrated electrical AC systems, the demand-supply balance has to hold at every instant to ensure frequency and voltage stability. Control power[2] is used to physically balance deviations on short time scales. This paper provides an overview of control power systems and markets, with a focus on the role of variable renewable electricity sources (VRE) such as wind and solar power. We present new empirical data from Germany, where installed VRE capacity now exceeds 70% of peak load. Surprisingly, both volume and cost of reserving capacity as control power have decreased since 2008, despite a doubling of installed VRE capacity.

Electricity generation from renewables has been growing rapidly during the last years, driven by technological progress, economies of scale, and deployment subsidies. Renewables are one of the major options to mitigate greenhouse gas emissions and are expected to grow significantly in importance throughout the coming decades (IPCC 2011, IEA 2012, GEA 2012, Luderer et al. submitted). As hydro power potentials are largely exploited in many regions, and biomass needed in other sectors than power generation, much of the growth will come from wind and solar power.

As a consequence of the inherent stochastic nature of wind speeds and solar radiation, VRE generation is uncertain ahead of realization. Deviates from forecasted generation need to be balanced by the power system. Short-term forecast errors tend to increase the utilization of control power, and potentially increase the reserve requirement. The impact of VRE on control power is sometimes seen as a major and costly challenge for integrating these technologies into power systems and widely discussed in the literature (Grubb 1991, Gross et al. 2006, Denny & O'Malley 2007, Milligan et al. 2009, Holttinen et al. 2011, Katzenstein & Apt 2012, Pérez-Arriga & Battle 2012).

In a broad literature review (Hirth 2012), we find that wind integration studies and other power system modeling exercises often estimate the costs impact of VRE on balancing systems to be positive, but small (below 5 €/MWh_{VRE} even at high penetration rates). However, studies based on market prices sometimes report much higher costs, even at low penetration rates. To shed light on this issue, the present study provides a more detailed discussion of control power in the context of the increasing penetration of wind and solar power.

While discussing the role of variable renewables, we also provide a condensed yet comprehensive overview of European balancing systems in general, and the German control power market and imbalance settlement system specifically. Previous publications have compared control power systems and markets internationally (Rebours et al. 2007a, 2007b, TenneT 2011, ENTSO-E 2012a, Ela et al. 2011a, Cognet & Wilkinson 2013). Vandezande et al. (2010) discusses economic aspects of market design. Kristiansen (2007) provide a comprehensive discussion of the Nordic balancing system and Ela et al. (2011a, 2011b) of American systems. However, we are not aware of a publication that provides a comprehensive overview of the German balancing system. More importantly, the mentioned studies discuss technical features and market design, but rarely present market data. A key contribution of this article is to present and discuss comprehensively observed price and volume data. In that sense, this article is much more empirical than the previously published literature. There exists some empirical literature on the German system, but that focusses quite narrowly on market design changes on the German market for tertiary control (Riedel & Weigt 2007, Growitsch & Weber 2007, Müller & Rammerstorfer 2008, Haucap et al. 2013). Formal modeling, being theoretical, numerical or econometric, is beyond the scope of this paper.

This article focuses on electricity, although the natural gas market features a similar system of balancing energy (KEMA & REKK 2009, ACER 2011).

[2] There is a multitude of names for this service. We follow here European Transmission System Operator terminology and use the term "control power" (UCTE 2009). In Germany and the Nordic countries, "regulating power" (*Regelleistung*) is more commonly used. Other names include balancing reserve, reserve power, or balancing power. Certain types of control power are sometimes erroneously used to describe control power, such as regulation, load following, operating reserve, contingency reserves, or frequency control.

The paper is organized as follows. Section 2 gives an overview of balancing systems. It clarifies which actors are involved, outlines the technical characteristics of different types of control power in Europe, and explains how they are used. Section 3 discusses how the reserve requirement is determined. We show that despite a massive expansion of variable renewables, German reserves were significantly reduced. Section 4 discusses control power markets. We show that prices have dropped dramatically in Germany and propose some explanations for that. Furthermore, we suggest how VRE participation in control power provision could be stimulated. Section 5 discusses the other side of the balancing system: imbalance settlement. We argue, in line with the economic literature, that price signals are currently inefficiently low in Germany, and propose remedies. Section 6 briefly discusses Nordic and American balancing systems and identifies elements that could be adopted. Section 7 concludes.

Overall, we find that the impact of VRE on control power is less dramatic than sometimes believed. VRE growth has had moderate impact on volumes and costs of control power at best, and will continue to have limited affect during the next years. Other factors, such as efficiency gains from market integration, have overcompensated for VRE growth. Nevertheless, we propose several measures to increase the efficiency of control power systems: On control power markets, primary and secondary control should be tendered daily and for each hour, similar to wholesale markets. Control power pricing should be priced marginally, not in pay-as-bid auctions as today. Imbalance prices should be published within one hour after real time, marginal pricing should be applied here as well, and the costs of capacity provision should be allocated via imbalance prices.

2. Fundamentals of control power

This sections explains how balancing systems work, how control power relates to other ancillary services, and gives an overview of the types of control power used in the Union for the Co-ordination of Transmission of Electricity (UCTE, "European Interconnection") and other European synchronous systems.[3] European power markets have been described as "bilateral", "pool", or "self-dispatched" markets, in contrast to U.S. markets, where system operators often have a more active and broader role. American balancing systems are briefly touched upon in section 6.2.

2.1. Balancing systems

We use the term "balancing system" to describe the set of institutions that are used to maintain, and, if necessary, restore the demand-supply balance of active power in integrated power systems. This includes the procurement and activation of control power, the allocation of its costs, and the incentives for market actors to avoid imbalances.

Three types of actors play a role in balancing systems: transmission system operators, balance responsible parties, and suppliers of control power. Figure 1 gives a high-level overview of their roles and interactions.

Balance responsible parties (BRPs) are market entities that have the responsibility of balancing a portfolio of generators and/or loads. Utilities, sales companies, and industrial consumers are BRPs. Each physical grid connection point is assigned to one BRP, and usually BRP several physical grid connection points. BRPs deliver binding generation and load schedules to the system operators, usually one day in advance. These schedules can be adjusted until about one hour ahead of delivery. If actual in-feed and consumption deviates from the schedule, system operators balance the system by physically activating control power. BRPs are financially accountable for deviations from their schedules.

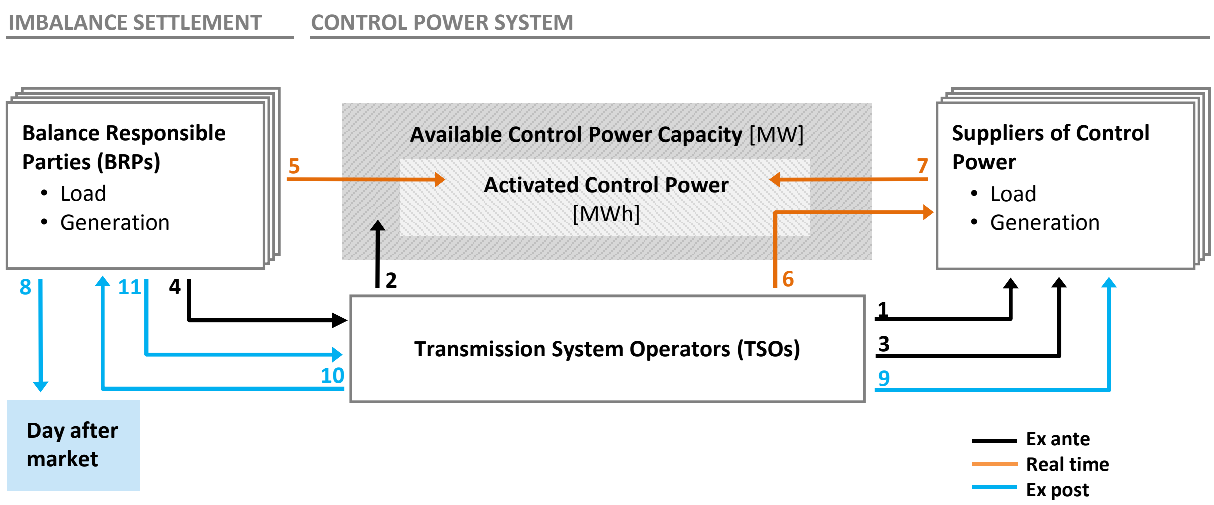
[3] As organization, the UCTE has been replaced by "ENTSO-E Regional Group Continental Europe". We stick with the former name for convenience. Similarly, we still use the name "Nordel" for the Nordic synchronous system.

Transmission system operators (TSOs) operate the transmission network and are responsible to balance supply and demand in their control area (balancing area). Control areas are geographic regions, usually of the size of countries. The control area imbalance is the sum of all BRP imbalances. Specifically, TSOs have four obligations:

- determine the required amount of capacity that has to be reserved as control power ex ante (section 3)
- acquire the control power capacity and determine the price paid for capacity and energy ex ante (section 4)
- activate the control power in moments of physical imbalance in real time
- determine the price of balancing energy, and clear the system financially by charging BRPs according to their imbalance and/or recovering expenses via grid fees ex post (section 5).

Suppliers of control power reserve positive or negative capacity, and deliver energy once activated by the TSO. They are obliged to deliver energy under pre-specified terms, for example within a certain time frame. Suppliers are traditionally mostly generators, but can also be consumers.

We call the institutional setup for acquiring control power the “control power market” and the system to settle BRP’s imbalances financially the “balancing power market”.



TSOs
1 Prequalification of control power providers
2 Dimensioning of required capacities $SC^{+/-}$, $TC^{+/-}$
3 Tender (pay as bid) and calculation of merit order lists for activation order of suppliers
6 Activation signal for $SC^{+/-}$, $TC^{+/-}$
9 Energy and capacity payments
10 Calculation of balancing energy expenses for activated control power

BRPs
4 Binding schedules of load and generation
5 Causing control power demand
8 Reduction of accounting imbalances
11 Remuneration of balancing energy expenses (note: in Germany, the capacity charge is socialized and reckoned up in grid fees)

Suppliers of Control Power
7 Supply of $SC^{+/-}$, $TC^{+/-}$

Figure 1. Overview of a balancing system.

2.2. Power and Energy, Negative and Positive

Unlike on many wholesale markets for electricity, transactions in the balancing system regularly involve capacity and energy. Capacity is reserved in advance for periods of days to years, and activated (deployed, ordered, called upon) shortly before real time for periods of seconds to hours.

Typically suppliers of control power receive a capacity (€/MW per hour)[4] because capacity reservation occasions opportunity costs and/or energy payment (€/MWh) since activation is costly. Hence the price for control power can be classified as a two-part tariff.

Furthermore, it is important to distinguish between positive (upward-regulating, incremental) control power and negative (downward-regulating, decremental) control power. Positive control power is needed if the system is short of energy (undersupplied) and negative control power if the system long of energy (oversupplied). Negative control energy is provided by reducing generation or increasing consumption. While energy prices for positive control are always positive, they can be positive or negative for negative control (suppliers pay the TSO for being activated, that is, for producing less).

2.3. Control Power, Re-Dispatch, and other Ancillary Services

Control power is one of several “ancillary services” that TSOs use to secure and restore system stability. Short-term active power imbalances, which control power is meant to solve, is not the only threat to stability. If power flows on transmission lines exceed rated capacity, TSOs use “counter-trading” or “re-dispatch” to geographically re-locate generation and reduce line flows. Local reactive power imbalances cause voltage deviations that require capacitive or inductive reactive power, sometimes called “voltage support”. Power plants with “black-start capabilities” are used to re-build power supply after a blackout.

It is important to keep in mind that control power is not used to change transmission flows or to steer local voltage levels, but to stabilize the active power balance. In small island systems different ancillary services are often less clearly separable.

2.4. Types of Control Power in Continental Europe

Most power systems feature different types of control power. They can be distinguished along several dimensions.

- Operating v. contingency reserve: operating reserves are used to balance operational disturbances such as load forecast errors, while contingency reserves are meant to replace tripped power plants or transmission lines.
- Spinning v. stand-by reserve: spinning or synchronous reserves are synchronized generators or consumers that can response fast. Stand-by reserves, even fast-starting equipment such as open-cycle gas turbines or hydro plants, take more time to be activated.
- Reserves that balance a control area v. reserves that balance an interconnected synchronous system (interconnection). Synchronous systems usually consist of several of control areas.
- Positive v. negative reserves.
- Time of activation (fast v. slow).
- Way of activation (manual v. automatic).

These dimensions are not independent. For example, spinning reserves can be activated quicker than stand-by reserves. A unit of capacity can be used both as operational and contingency reserve (but of course can only be activated once).

Since there are various sources of imbalances with different characteristics (see section 3.1), in most power systems a set of different types of control power has evolved. In the synchronous power

[4] This is the price of reserving capacity per MW and per hour, which is not identical to the price for delivering one MWh of electrical energy. TSOs report prices usually in €/MW per day, €/MW per week, or €/MW per month. Market actors sometimes use €/kW per year. We report all capacity prices as €/MW per hour (€/MWh). Note that despite having the same unit, these capacity prices have nothing to do with energy prices.

system of continental Europe (the former UCTE) three types of control power are used: primary control, secondary control, and tertiary control (minute reserve) – each positive and negative. They differ in purpose, response time, and the way they are activated (Table 1).

Primary control power ($PC^{+/-}$) can be fully deployed within 30 seconds. Being a shared resource within the UCTE, it is not activated by TSOs but activated based on the locally measured grid frequency. If the frequency deviates more than 20 mHz from 50 Hz ("dead band"), PC is activated; it is fully activated at 200 mHz deviation. PC can be classified as a fast, automatic, spinning reserve that is used to balance the synchronous system. The share of PC that is activated A_{PC} can be written as a linear function of deviation of the instantaneous grid frequency f_t from the nominal frequency of 50 Hz, f_n.

$$A_{PC} = \begin{matrix} 0 & \text{if } (f_t - f_n) < 20 \text{ mH} \quad \text{(dead band)} \\ \lambda \cdot (f_t - f_n) & \text{if } 200 \text{ mH} < (f_t - f_n) < 200 \text{ mH} \\ 1 & \text{if } (f_t - f_n) > 200 \text{ mH} \end{matrix} \tag{1}$$

Secondary control power ($SC^{+/-}$) has to be available within five minutes after activation. It is activated automatically and centrally by TSOs. Activation depends mainly on the balance of the national control areas (physical net imports minus scheduled net imports), but also takes frequency deviation into account (UCTE 2009, P1 and A1). $SC^{+/-}$ can be supplied by some stand-by hydro plants, but is mainly provided by synchronized thermal generators. Hence, it is an automatic reserve that balances both the synchronous system and the control area and is, to a large extent, it is a spinning reserve. The share of SC that is activated A_{SC} can be written as a linear function of the frequency deviation and the deviation of the control area's physical net imports M_t from the scheduled net imports M_s.

$$A_{SC} = \theta \cdot (M_t - M_s) + K \cdot (f_t - f_n) \tag{2}$$

The parameter K is set roughly to $K = -\lambda$. The activation signal A_{SC} is smoothed by a proportional integral controller (UCTE 2009, Ela et al. 2011a), equation (2) gives the steady-state activation.

Tertiary control power ($TC^{+/-}$) is usually used to replace $SC^{+/-}$. It is either directly activated or in schedules of 15 minutes. In Germany, it has to be available within seven minutes. Activation is a manual decision usually based on current and expected deployment of $SC^{+/-}$. Both synchronized and fast-starting stand-by generators supply $TC^{+/-}$.

Table 1: Types of Control Power in the UCTE

	Primary Control	**Secondary Control**	**Tertiary Control (Minute Reserve)**
Response Time (full availability)	30 s, direct (continuously)	5 min, direct (continuously)	7-15 min, direct or schedule
System	UCTE	UCTE and Control area	UCTE and Control area
Control Variable	Frequency deviation from 50 Hz	Balance of the control area; Frequency deviation	Amount of $SC^{+/-}$ activated
Activation	Based on local frequency measurement	Centralized (TSO); active call through IT	Centralized (TSO); active call through phone / IT
Suppliers (typically)	Synchronized generators, (large consumers)	Synchronized generators, stand-by hydro plants, large consumers	Synchronized and fast-starting stand-by generators, large consumers
Reserved Capacity (see section 3)	3000 MW in UCTE (600 MW in Germany)	Decided by TSO (2000 MW in Germany)	Decided by TSO (2000 MW in Germany)

More technical details are provided by UCTE (2009) and Rebours et al. (2007a).

After a contingency, such as the loss of a large generator, control power is used to stabilize and restore grid frequency. When a generator trips, consumption exceeds production and the power system is imbalanced. As a consequence, the frequency drops in the entire synchronous network of the UCTE. The speed of the drop depends on the inertia (inertial response) of the power system, itself depending on the energy stored in the rotating masses of generators, and reduced consumption of frequency-dependent loads (Weißbach 2009, UCTE 2009 A1). The frequency drop activates PC^+ in the entire UCTE. The parameter λ is calibrated in such way that enough PC^+ is activated to compensate for the failed generator. After 30 seconds PC is fully available, demand equals supply again, and the grid frequency is stabilized. Within five minutes, SC^+ is activated, mainly in the control area of the failed generator. Now generation exceeds consumption and the frequency rises. Over time SC^+ is replaced by TC^+. Once the frequency has reached 50Hz, PC is deactivated, and SC^+/TC^+ is only deployed in the control area of the tripped generator. After about one hour, the failed generator is usually replaced by capacity contracted on the market and control power is deactivated again.

However, control power is not only used to stabilize and restore frequency by balancing the synchronous system, but also to balance control area imbalances. Take the example that wind generation is higher than expected in Germany, but lower by the same amount in Spain. Because the synchronous system is still balanced, the frequency will remain stable at 50 Hz. Nevertheless, SC^-/TC^- is activated in Germany and SC^+/TC^+ in Spain. In the remaining control areas, no control power is activated, and PC is not activated anywhere. Hence, control power is in the UCTE used to simultaneously balance *two* systems: the synchronous system of the UCTE as a whole, and each control area.

2.5. Control power and Other Power Markets

Control power markets are embedded in a system of wholesale electricity markets. Table 3 gives an overview and puts German control power markets into the context of other power markets. Control power markets and spot markets are not independent from each other. For example, a BRP who projects to be out-of-balance two hours ahead can decide to balance its portfolio with intraday trades, or remain unbalanced and pay the imbalance price. Similarly, TSOs can use the intra-day market when they foresee the control area to be unbalanced for several hours.

Table 2: Wholesale markets for electricity in Germany.

	PC	**SC**	**TC**	**Intra-day**	**Day-ahead**	**Forwards & Futures**
Gate closure (time between activation ad delivery / time between last bid and delivery)	30 sec	5 min	7 min	45 min	12-36 h	day … years
Program time unit ("schedule"; time span during which the product is supplied)	- (continuous)	- (continuous)	15 min	15 min / 1 h	1 h … 1 day	day … years
Buyer	TSOs			Market actors (consumers, traders, retail companies)		

Trading platform	www.regelleistung.net			Power exchange, over the counter (OTC)	
Pricing rule	pay-as-bid auction			price per contract	common clearing price auction (PX); price per contract (OTC)
Capacity payment	yes			no	
Energy payment	no	yes	yes	yes	

2.6. The European Target Model: Balancing Framework Guideline and Network Code

As part of the integrated European electricity market, the European Union aims at harmonizing and integrating European markets for control power. As a consequence, the European balancing system, and all of its markets, will be fundamentally remodeled in the coming years. In a joint effort, EU institutions, energy regulators (Agency for the Cooperation of Energy Regulators ACER) and European TSOs (European Network of Transmission System Operators for Electricity ENTSO-E) are developing market schemes that allow more international cooperation and market integration. This process led to the publication of Framework Guidelines (ACER 2012), based on which currently Network Codes are drafted (ENTSO-E 2013).[5] With this paper, we aim at supporting the implementation process by providing information on market design and price impacts to a wider audience.

3. Determining the Required Reserve Capacity

TSOs have to estimate the amount of reserves to be contracted ex ante. The methodologies used for doing this vary across types of control power and across countries. TSOs can use stochastic (probabilistic) or deterministic approaches to estimate the reserve requirement. In deterministic approaches, reserves are large enough to cover the largest possible contingency (N-1 criterion). In probabilistic approaches, reserves are dimensioned to balance the system with a certain probability.

Weather stochastic or deterministic, TSOs can determine the reserve requirement either for longer time periods such as one year (static dimensioning) or more frequently depending on the current or expected load or wind situation (dynamic dimensioning).

TSOs can use dynamic or static approaches: in static approaches, reserves are determined for longer periods such as one year; in dynamic approaches they depend on the current or expected situation, for example load levels or wind in-feed.

In continental Europe, reserve requirements are regulated by the UCTE (2009), which prescribes a common deterministic-static approach for PC, and leaves the decision for SC and TC dimensioning to the TSOs. European TSOs have agreed to reserve 3000 MW in the UCTE as $PC^{+/-}$, sufficient to compensate the loss of two large nuclear reactors. The total amount is distributed among control areas proportionally to previous year's generation (UCTE 2009, P1). The German control areas currently jointly have to reserve around 600 MW.

The necessary capacities of $SC^{+/-}$ and $TC^{+/-}$are set for each control areas by the respective TSOs. For $SC^{+/-}$, UCTE (2009, P1 B-D5) proposes different methodologies, such as a stochastic "risk management approach" or a deterministic-static "empiric noise management approach". The latter is an empirical approximation based on peak load l_{max} (in MW). Specifically, the reserved positive and negative secondary control capacity C_{SC^+} and C_{SC^-} is determined by:

$$C_{SC^+} = C_{SC^-} = \sqrt{10 \cdot l_{max} + 50^2} - 50 \qquad (3)$$

[5] For overviews, see www.acer.europa.eu/Electricity/FG_and_network_codes/Pages/Balancing.aspx and www.entsoe.eu/major-projects/network-code-development/electricity-balancing/

For $TC^{+/-}$, UCTE (2009) does not provide such methodologies, but relies on TSO judgment. As a consequence, the amount of SC/TC reserves vary widely even within the UCTE – from 5% of average load in France to 14% in Belgium (Cognet & Wilkinson 2013). In Germany, TSOs use a probabilistic approach to determine SC and TC capacities jointly. We will discuss this in the following two subsections.

3.1. Variables that Cause System Imbalances

Several factors cause imbalances in power systems. One way to categorize them is to distinguish stochastic from deterministic processes (Table 3).[6] Stochastic processes are forecast errors of generation and load. Traditionally, forecast errors of load and unplanned outages of thermal and hydro plants or their grid connection (contingencies) have been the most important factors in this group. Lately, forecast errors of VRE have been added to the list. Deterministic processes are the deviations between the stepwise schedules and continuous physical variables.

Table 3: Control power influencing variables

	Stochastic	**Deterministic**
Thermal and Hydro Generation	Unplanned power plant outages	Schedule leaps of generation and load
VRE Generation	Forecast error for wind and solar generation	
Load	Load forecast error	

Unplanned power plant outages are stochastic processes. They induce an unplanned power shortage in the electricity system and therefore only require positive control power. The probability of an outage is influenced by the characteristics of plants (technology, fuel, age) and the frequency of start- up and shut-down processes. Usually power plant outages last for several hours or days. However, only a part of this time span the outage is relevant for control power. In Germany, BRPs are obliged to replace tripped generators within one hour with scheduled capacities from their portfolio or the market.

Forecast errors of VRE generation and load affect the positive as well as the negative control power demand: An overestimation of VRE generations leads to a power shortfall that requires the activation of positive control power. An underestimation has the opposite effect. Wind, solar, and load forecasts are inherently uncertain due to the stochastic nature of the underlying physical processes. While day-ahead forecasts are significant in size, they improve as the prediction horizon shortens. If intra-day markets are liquid, it is only the prediction errors of the latest forecast that requires control power.

Next to these inherently stochastic processes, there is another source of system imbalances: deterministic processes resulting from the way contracts are designed in electricity markets. Schedules for generation and load are specified as discrete step functions in 15 minute-intervals. However, loads, VRE, and – to a lesser extend – also dispatchable generators do not change in steps, but smoothly (Figure 2). The deviations of actual load and production from scheduled load and production are called “schedule leaps.” These leaps can have a substantial impact on the control

[6] This has nothing to do with stochastic / deterministic estimation methodologies for reserve dimensioning.

power demand (Figure 3), see also Weißbach & Welfonder (2009). Shorter dispatch intervals result in a reduced need for balancing (section 6.2).

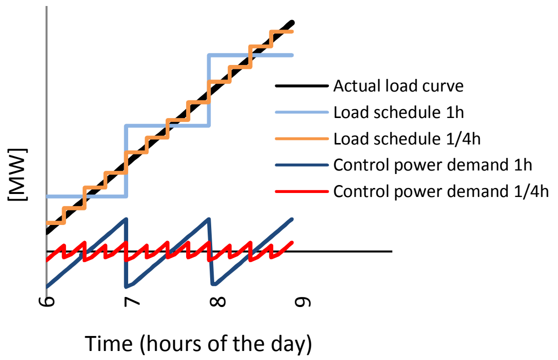


Figure 2. How discrete schedules cause imbalances.

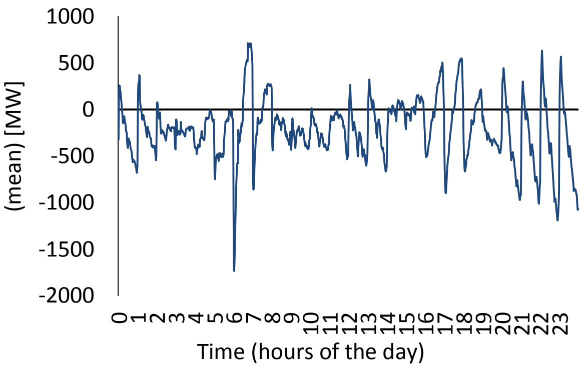


Figure 3. Average German system imbalance for every minute of the day. There are clear systematic patterns just before and after full hours.

While BRPs are obliged to schedule on a quarter-hourly basis, spot market trading on many power exchanges has an hourly granularity. Consequently, many BRPs use hourly schedules, which results in higher deviations (Consentec 2010).

The control area imbalance is the sum of all these deterministic and stochastic imbalances. Usually, individual imbalances cancel out to a large extent. In statistical terms, the control area imbalance follows the joint distribution of the individual distribution functions of the factors that cause imbalances. We will discuss in turn how to estimate these distributions empirically.

3.2. Statistical Convolution

The German TSOs use a probabilistic approach to determine $SC^{+/-}$ and $TC^{+/-}$ capacities, sometimes called the "Graf/Haubrich approach" (Consentec 2008, 2010). First, the individual density functions of all random variables are estimated, either from historical data or theoretical considerations. Then, the joint density distribution is derived by means of statistical convolution. Thereby it is assumed that the individual factors are independent from each other. Finally, positive and negative reserves are set in a way that the area under the density function equals a pre-defined level of system security. Figure 3 gives a high-level overview.

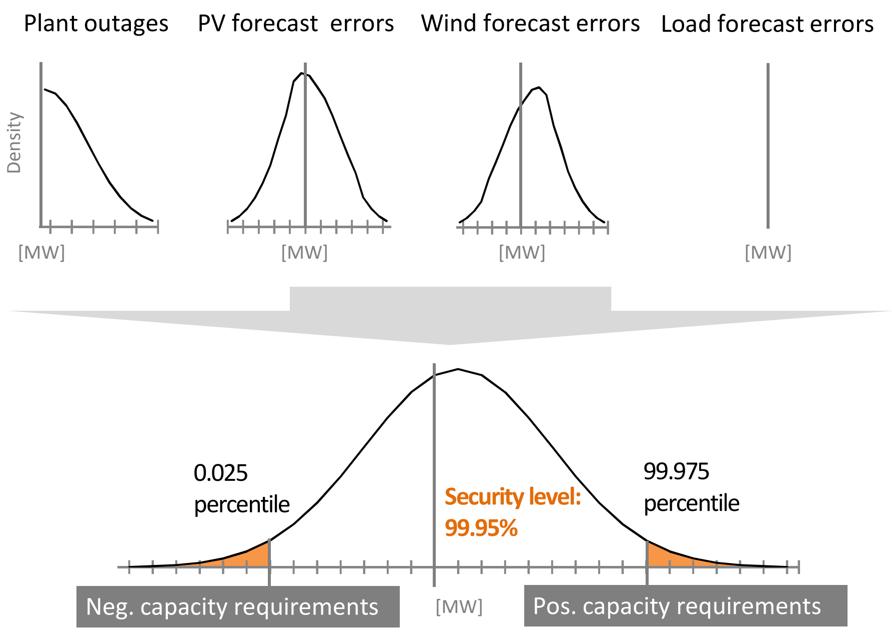


Figure 4. Probabilistic approach for ex-ante determination of requiring capacity of $SC^{+/-}$ and $TC^{+/-}$. The 0.025% percentile and the 99.975% percentile of the joint density function determine the required amount of reserves.

In Germany, the security level was recently increased to 99.95% (Consentec 2010). This corresponds to approximately four hours of the year where the momentary control power demand can exceed the reserved capacities. In those rare circumstances, TSOs support each other with ad hoc measures. The German TSOs determine the required capacity for the next quarter based on empirical data of the previous twelve months.

Many studies have estimated the impact of VRE on control power reserve requirements. Good surveys are provided by Ela et al. (2011a) and Holttinen et al. (2011). However, to the best of our knowledge, none of these studies is based on statistical convolution.

3.3. TSO Cooperation

The size of a control area determines crucially the shape of the different density functions. A larger control area with a higher number of more diverse loads leads to a more narrow distribution of load forecast errors. Similarly, a geographically larger control area with more and more widely dispersed wind and solar generators leads to a more narrow distribution of VRE forecast errors.

Since 2009/10 the German TSOs closely cooperate in the field of control power (*Netzregelverbund*). Today, both reserve dimensioning and activation is done jointly. In practice, Germany can be treated almost as one control area (Zolotarev et al. 2009, Zolotarev & Gökeler 2011).

Since 2012, the cooperation is expanding to surrounding control areas as “International Grid Control Cooperation” (IGCC), as one of several European regional cooperations. By early 2013, the Danish, Dutch, Swiss, and Czech TSO have joined. At this stage, the IGCC members outside Germany cooperate in terms SC activation, but reserve capacities are dimensioned separately. This “bottom-up” process develops in parallel with the “top down” framework guideline process described in section 2.6.

3.4. Control Power Capacities in Germany

Variable renewables, being inherently stochastically electricity sources, *ceteris paribus* increase the need for balancing, both capacity reservation and utilization. In academic and policy circles, it seems to be often believed that indeed they have become major drivers for control power demand. However, in this subsection we present empirical data from Germany that show that this is not necessarily the case: Control power reserves were reduced during the last five years, while VRE capacity doubled. Other factors, such as the cooperation of TSOs or improved imbalance management, must have overcompensated for the strong growth of VRE. We conclude that, at least at moderate VRE penetration rates, control power is not a major barrier for system integration, and not a major driver of integration costs.

In 2012, German TSOs tendered about 600 MW $PC^{+/-}$ and 2000 MW each of $SC^{+/-}$and $TC^{+/-}$ (Table 4). This means that total upward and downward regulation capacity was roughly 4600 MW. This compares to a peak load of 80-90 GW and an installed combined wind and solar capacity of 64 GW (end of 2012). The share of VRE in energy terms increased from 7% to 13% between 2008 and 2013.

Table 4: Contracted volumes of control power in Germany (MW).

	$PC^{+/-}$	SC^{+}	SC^{-}	TC^{+}	TC^{-}
2008	670	3100	2400	3200	1900
2009	670	2900	2200	2700	2700
2010	640	2400	2100	2300	2400
2011	630	2200	2100	2100	2500
2012	600	2100	2200	1700	2300

Rounded for better readability.

Figure 4 shows the contracted volumes of secondary and tertiary control power. Since 2008, total quantities decreased by more than 20%. While downward-regulation quantities remained roughly stable, upward-regulation quantities decreased by about 40%. This was possible even though the level of security was increased from 99.9% to 99.95%.

Several factors might have caused the decrease in volumes: wind and solar forecasts have become better; TSOs might have become more cost-conscious and decreased the security margin; load forecasts might have become better. However, the cooperation of TSOs (section 3.3) is probably the single most important reason for this decrease.

Figure 5 compares these quantities to the installed capacity of variable renewables. While VRE capacity doubled, control power reserves decreased significantly. Of course that does not mean that wind and solar power reduce the balancing reserve requirement. However, it shows that variable renewables were *not* the dominant driver for reserve requirements. Other factors can over-compensate the impact on VRE on reserve requirements, and apparently have done so during the last five years in Germany.

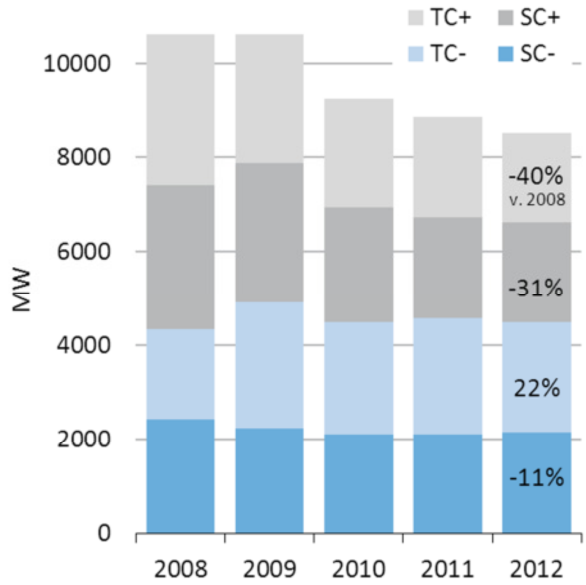


Figure 5. Tendered volumes of secondary and tertiary control power in Germany.

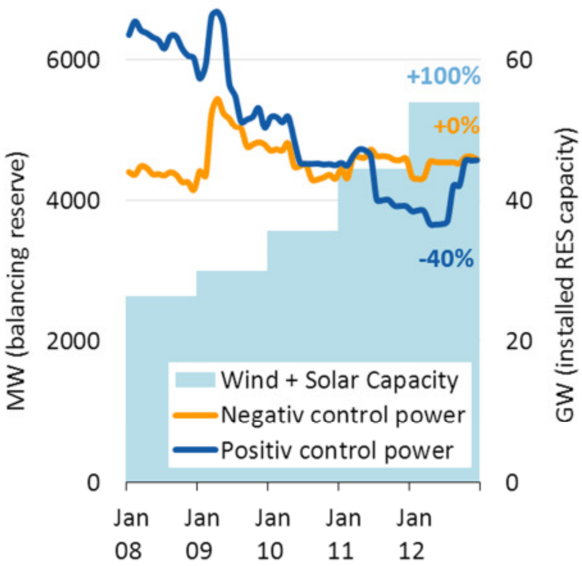


Figure 6. The demand for control power and growth of variable renewables in Germany. Despite the installed capacity of wind and solar power doubling since 2008, the demand for regulating power decreased.

In this section we have explained that a number of factors determine the reserve requirement for control power: plant outages, load forecast errors, and VRE forecast errors. While wind and solar power increase the reserve requirement, they are not necessarily the dominating factors, even at substantial penetration rates. Specifically, German reserve capacity has been reduced by 20% during the last five years, while installed VRE capacity doubled.

3.5. Policy Recommendations

As currently discussed in Switzerland (Abbaspourtorbati & Scherer 2013), reserve dimension could be dynamic and price-elastic. Dynamic dimensioning means that, depending on the projected load, wind, and solar conditions, different amount of reserves are procured. For example, if a wind front is expected to arrive the next day, more reserve can be procured than for a calm day.

Price-elastic dimensioning means that the amount of capacity reserved should reflect the price of capacity. When capacity reservation is cheap, it is probably welfare-improving to procure more reserves, thereby increasing the security level.

4. Control Power: Market Design and Price Formation

The last section discussed methodologies to estimate the reserve requirement for control power. As a next step, TSOs need to acquire that amount of capacity from generators and loads. The acquisition is mostly organized nationally and follows different concepts in each country. A wide range of institutional setups exist: supply obligation for generators with or without compensation, mandatory offers by generators, dedicated tender platforms, procurement via power exchanges, or joint spot and control power markets. Rebours et al. (2007b), ENTSO-E (2012a) and Cognet & Wilkinson (2013) provide comprehensive overviews of market rules. TenneT (2011) provides a detailed comparison of the Dutch and the German market. Ela et al. (2011b) discusses American market design.

4.1. Control Power Market Design in Germany

In Germany, after the liberalization of spot markets, ancillary service markets were created in 2001 when the regulator forced to replace bilateral contracts between generators and TSOs with public procurement auctions. Since late 2007, the four German TSOs procure control power via their common platform www.regelleistung.net. The auction design is prescribed by the energy regulator Bundesnetzagentur. Table 5 summarizes auction design as it is in place since mid-2011, when auction periods were shortened and minimum bid sizes reduced.

TSOs determined the reserve requirement independently from control power prices, hence the demand is perfectly price-inelastic. Since only TSOs procure control power in one common tender, it is a single-buyer auction. Bidders have to prove that they can deliver control power according to the UCTE requirements (Table 1) before bidding ("prequalification"). All auctions are pay-as-bid auctions: in contrast to uniform (marginal) pricing as on spot markets, bidders receive the price they bid (on pay-as-bid auctions in energy markets see Morey 2001 and Chao & Wilson 2002). Bids are accepted based on their capacity price only; activation is done according to the energy price. Hence, there are two independent merit orders. PC and SC are tendered for a week, TC for each day. PC is a symmetric (bi-directional) base product, which means both upward and downward regulation has to be provided for an entire week. SC is tendered separately as positive and negative reserves for peak and off-peak periods. TC is auctioned in blocks of four hours, separately for negative and positive. Hence, there are four SC products and twelve TC products per acution. Minimum bid sizes apply, but generators can be pooled. Riedel & Weigt (2007), Growitsch & Weber (2007), and Müller & Rammerstorfer (2008) discuss consequences of introducing common tendering. Haucap et al. (2013) discuss several market design changes and provide econometric evidence that common tendering has decreased TC prices. Müsgens & Ockenfels (2011) discuss the ex-post publication of bidding information. Abbaspourtorbati & Scherer (2013) discuss price-elastic procurement in a similar market design in Switzerland.

Table 5: Control power market design in Germany since 2011.

	Primary Control	Secondary Control	Tertiary Control
Platform		www.regelleistung.net	
Price		pay-as-bid	
Auction Period	week	week	day
Number of Products	1 (base, symmetric)	4 (positive/negative; peak/off-peak)	12 (positive/negative; blocks of four hours)
Program Time Unit	week	week (peak/off-peak)	four hours
Capacity Payment	yes	yes	yes
Energy Payment	no	yes	yes
Minimum Bid	1 MW	5 MW	5 MW
Number of Suppliers	14	17	35
Pooling possible	yes	yes	yes

Growitsch et al. (2010) and Heim (2013) provides a number of indicators that support the impression that the market was quite concentrated and several suppliers were pivotal. In June 2011, auction rules were significantly altered in order to promote market entry of new actors. Apparently, that was successful: the number of prequalified suppliers has strongly increased (Figure 7). Today, municipal utilities (*Stadtwerke*), industrial consumers, aggregators, and foreign generators are pre-qualified for all three control power types.[7]

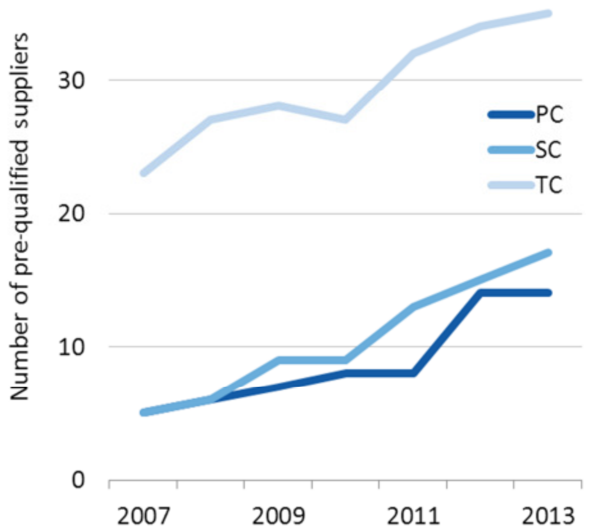


Figure 7. The number of pre-qualified suppliers of control power has strongly increased during the last years. Today, industrial consumers, foreign utilities, and municipal utilities are active in all three sub-markets.

4.2. Market Size in Germany

This subsection presents and discusses empirical market data for control power in Germany, focusing on capacity prices. Providing comparable energy prices is not easily possible because of pay-as-bid pricing and non-disclosure of activation data.

The control power capacity market had a size of about € 400-800 million during the last years. For the TSOs, this is the cost of capacity reservation. In section 5.2, we estimate the control power energy market (the costs of activation) to have a size of € 200-300 million. Hence capacity payments are about two thirds of the total costs for control power.

In terms of costs, regulating power is by far the most important ancillary service in Germany (Figure 8). However, relative to the wholesale market for electrical energy, control power is a small niche (Figure 9). With a market size of € 420 million in 2011, it was about 2% the size of the German wholesale market for electrical energy (€ 25 billion). For households, the costs of the balancing systems are negligible. Including all taxes and levies, private households are paying about 280 €/MWh for electricity. Of that, the capacity costs of control power are about 0.3% (including energy costs 0.4%). For other markets, Rebours et al. (2007b) report the balancing system to cost 0.5-5% of the wholesale market for electrical energy. Cognet & Wilkinson (2013) find a similarly wide range of costs across European markets.

[7] List of prequalified bidders, www.regelleistung.net/ip/action/static/provider.

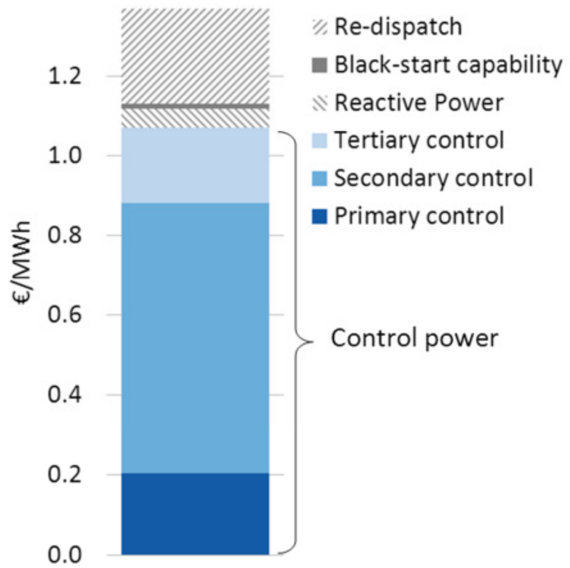


Figure 8. The total costs of ancillary services per MWh of total electricity consumed. Control power is by far the largest ancillary service in terms of market size (2011). See also Bundesnetzagentur (2012b).

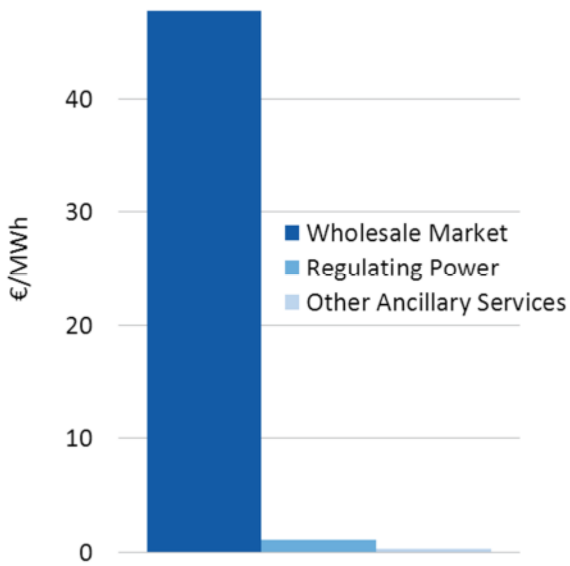


Figure 9. The costs of energy and ancillary service provision per MWh of consumed electricity. Control power is a very small market when compared to the wholesale market for energy (2011).

4.3. Price Development in Germany

This subsection discusses the price development of control power since 2008 and suggests some explaining hypothesis. Overall, prices decreased significantly, especially prices for upward regulation. The most important factors seem to be the decrease of volumes (section 3.4), market entry of new suppliers (4.1), and generation overcapacity due to the recession.

The average capacity price for control power in Germany during 2012 was between € 1 per MW and hour (€/MWh) and 16 €/MWh (Table 6). PC was the most expensive type of control power and TC^+ the cheapest. Note that while the SC and TC products are prices for one direction (up or down), the PC price is for regulation in both directions (symmetric). Maybe surprisingly, negative control power was on average three to four times more expensive than positive control. Overall, the market size was € 420 million, out of which two thirds was SC.

Table 6: Average capacity price (€/MW per hour) and market size (M€ per year, capacity payment only) in 2012.

	$PC^{+/-}$	SC^+	SC^-	TC^+	TC^-
Price (€/MWh)	16	3	12	1	3
Amount (MW)	600	2100	2200	1700	2300
Market size (M€)	90	50	220	10	60

Figure 10 shows monthly averaged prices since the common tender scheme was established in 2007. The four SC products as well as the 12 TC products are aggregated to symmetric base products to make the three types comparable. The first observation is that prices are very volatile. Moreover, there is a decreasing price trend in all types. The price level of SC is comparable to PC, which is plausible since they are close substitutes in terms of technical requirements of provision. Hence, observed prices confirm the expectation that PC and SC should be arbitrage-free. TC is much cheaper, because lower technical requirements allow much broader supply participation.

Figure 11 shows the price development of the four SC products individually. While during 2008 and 2009 SC^{+} was more expensive than SC^{-}, the opposite is true since then. A similar pattern can be observed in TC markets (not shown). Overall, price volatility is extreme.

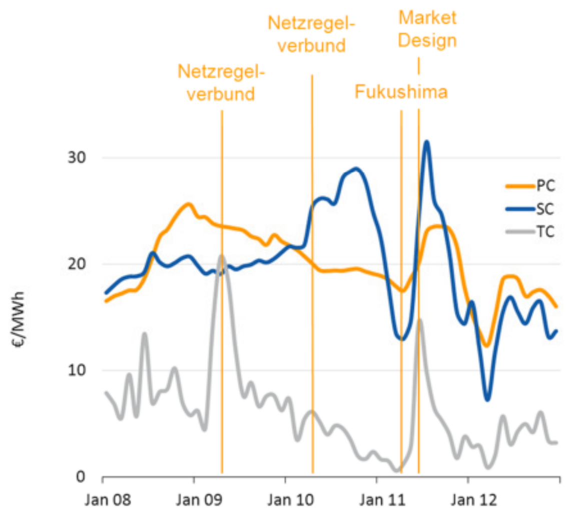


Figure 10. Capacity prices per MW and hour since 2008. The four SC products and the 12 TC products are aggregated to symmetrical base products in order to make prices comparable. The introduction of the control power cooperation, the phase-out of seven nuclear reactors, and the 2011 market design reform cause significant price reactions

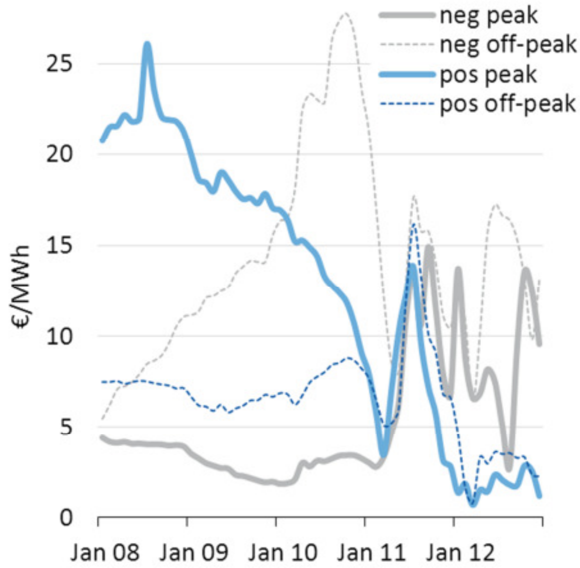


Figure 11. Capacity prices for different SC products. This more disaggregated perspective underlines how volatile control power prices are.

Figure 12 shows the price development as a yearly average. All control power types have experienced significant price drops. Compared to 2008, PC prices fell by 20%, SC by 30%, and TC prices by 50%. In conjuncture with decreasing tendered quantities, this caused the market size to contract 30-60% (Figure 13). The aggregated costs of control power provision fell by 50%. While the costs for positive control decreased dramatically, they even increased for negative control compared to 2008 (Figure 14).

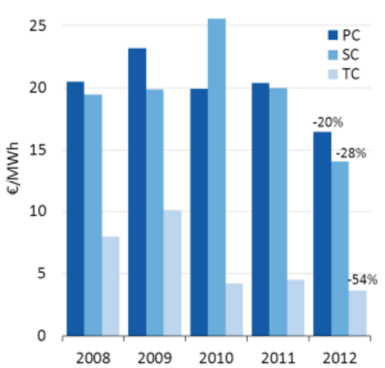


Figure 12. Control power prices as yearly averages. Products are aggregated to symmetric base, as in Figure 10. Relative changes compared to 2008.

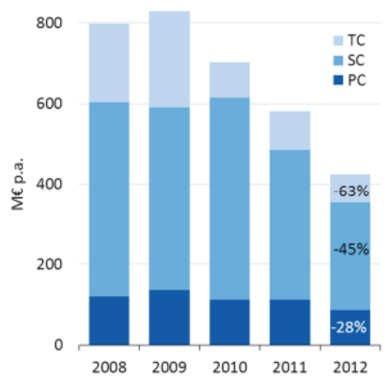


Figure 13. The market size of control power. The overall market size has contracted by 50% since 2008, with tertiary control decreasing most.

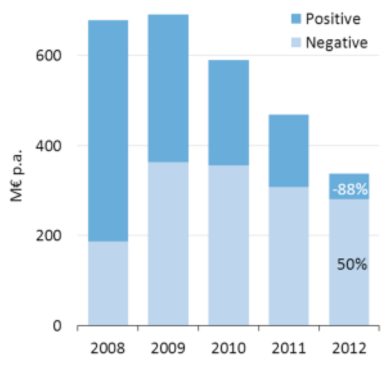


Figure 14. While the capacity costs for positive control power decreased by 90% since 2008, they increased by 50% for negative control.

Explaining the historical price movement is not trivial. A natural starting point is to look at the opportunity costs of suppliers. The opportunity costs of reserve capacity provision by a thermal plant are determined by the foregone profit from sales on the spot market. A generator that is in the money and generating electricity at its rated capacity can provide negative (downward-regulating) control power without opportunity costs. If that generator is to provide positive control, it has to operate constantly below its rated capacity. Reduced electricity sales and part-load efficiency losses determine its opportunity costs. However, most generators are not in the money during the entire time they reserve capacity.

A generator that provides negative control power has to keep producing even when making losses, while otherwise it would have ramped down to minimum load or even shut down. Hence, the opportunity costs of control power provision depend on the status the providing generator would be in otherwise, the spread between wholesale price and variable costs, ramping costs, and part-load efficiency losses.

Formally, the opportunity costs of providing positive spinning reserve, for example SC$^+$, O_{SC^+}, can be written as a function of the spot price p, the plant's variable cost c, minimum load P_{min} and the amount of control power the plant can deliver P_{SC}.

$$O_{SC^+} = \begin{matrix} (p-c) & \text{if } p > c \\ -(p-c) * P_{min}/P_{SC} & \text{if } p < c \end{matrix} \tag{4}$$

The opportunity costs of providing negative reserve O_{SC^+} can be written as this:

$$O_{SC^-} = \begin{matrix} 0 & \text{if } p > c \\ -(p-c) * (P_{min} + P_{SC})/P_{SC} & \text{if } p < c \end{matrix} \tag{5}$$

Figure 15 and Figure 16 show illustrative opportunity costs of providing spinning reserves for combined cycle gas turbines (CCGT), hard coal-fired, lignite-fired plants, and wind power. Under realistic parameters and 2012 European market prices for commodities these plants have variable costs of around 50 €/MWh, 33 €/MWh, and 21 €/MWh. If the spot price is just at a plant's variable cost, the generator is indifferent to run or not, and the opportunity cost of providing reserve is zero. At lower price levels plants are running minimum load if providing positive control power. The opportunity costs of control power supply are the losses they make on the spot market. At higher spot prices, plants run below full capacity. The opportunity costs of control power supply are the foregone profits on the spot market. To provide negative control power, plants have to run above minimum load, hence opportunity costs are higher if plants are out of the money. Once they are in the money, there are no opportunity costs. This illustration ignores any dynamic effects such as ramping or cycling costs, part-load efficiency losses, portfolio effects, and the fact that control power is provided for more than one hour. However, in general it is a plausible conclusion that high margins lead to low opportunity costs for the provision of negative control power.

Note that the opportunity costs for capacity reservation and energy delivery are different. Usually there are two different merit orders. The opportunity costs for positive and negative energy equal the marginal costs. Take the example of positive control. At prices above 50 €/MWh the capacity and the energy merit order are exactly reversed: it is cheapest for CCGTs to provide capacity, but cheapest for lignite to provide energy.

Because TC is to a large extent a stand-by reserve, opportunity costs are lower.

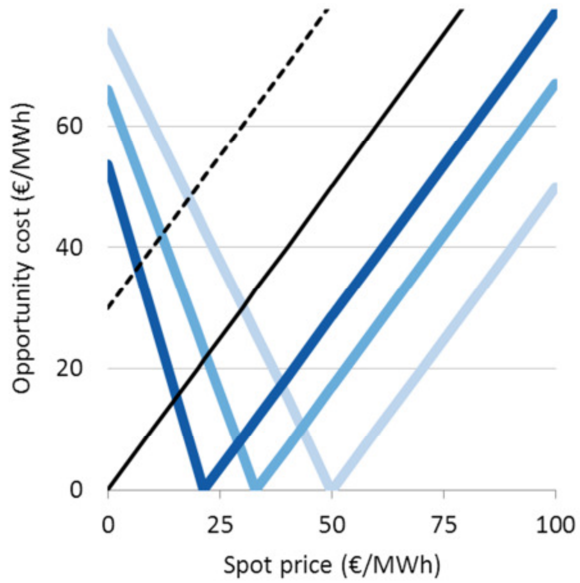


Figure 15. Opportunity costs of providing positive control reserves. Depending on the price, technologies with low or with high variable costs have lower opportunity costs.[8]

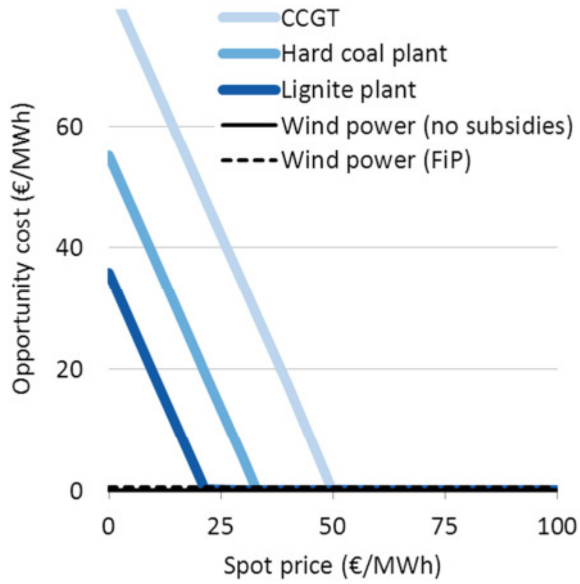


Figure 16. Opportunity costs of providing negative control reserves. Technologies with lower variable costs have lower opportunity costs. Plants that are in the money have zero opportunity costs.

Since 2008, the control power market was affected by a large number of shocks, which all potentially have influenced price development.

- Step by step TSOs cooperated more closely, reducing the demand for capacity reservation and activation (section 3.3).
- The design of the control power market was reformed several times, importantly in summer 2011 when weekly auctions for PC and SC were introduced.
- Several supply shocks hit the market, such as the entry of a large number of new companies (recall Figure 7), the shut-down of eight nuclear power plants in 2011, and a general oversupply of generation capacity as a consequence of the recession.
- Variable renewable capacity doubled, but at the same time forecasts were improved and a reform of the renewable support scheme in early 2012 exposed most renewables to market risks including the costs of forecast errors.
- Potentially market power abuse and regulator's response to that.

A more rigorous evaluation of the price development, such as multivariate regression analysis, is beyond the scope of this paper. Taken together, overcapacity, demand reduction, and market entry might jointly explain the strong overall price decrease. The price increase of negative control versus positive control can be explained by reduced margins on the spot market that reduce the opportunity costs of providing positive control power, but increase the costs of providing negative. The price spike during spring 2011 is related to the phase-out of seven nuclear reactors after the Fukushima accident. The price spike of TC prices in spring 2009 is connected to a shift of control power demand from SC to TC. Heim (2013) discusses the role of market power during the 2008-11 price increase for SC^-.

4.4. Barriers for VRE to Supply Control Power

The technical characteristics of wind and solar power make them well suited to provide negative control power. Also, since 2012, changes in the German support scheme have removed legal barriers

[8] Gas price 25 €/MWh, hard coal price 10 €/MWh, lignite price 3 €/MWh, CO_2 10 €/t, efficiencies for CCGT 55%, hard coal 40%, lignite 35%, min load CCGT 30%, hard coal 40% , lignite 50%, control range 20%.

for participation. However, the control market design constitutes a prohibitive entry barrier, which we discuss in this subsection.

In principle, VRE are well suited to provide negative control power when they generate electricity: unlike thermal plants, they can be ramped down very quickly without significant increase in maintenance costs. In contrast, they are not well suited to provide upward regulation. Given their low marginal costs, operating below generation possibilities would occasion higher opportunity costs in terms of foregone profits on the spot market than for thermal plants (Figure 15, Figure 16), see Kirby et al. (2010) and Bömer (2011).

Under the German feed-in-tariff, subsidized generators are not allowed to participate in control power markets. However, in early 2012 an optional feed-in-premium was introduced which allows generators to participate. So far, about 40% of VRE capacity has switched to the premium and would be legally able to enter control power markets.

However, wind and solar power currently do not seem to participate on the market in significant volumes (Köpke 2013).[9] The reason for that is the market design of control power markets that constitutes a significant entry barrier.

The ability of VRE to provide negative control power is limited to times when the primary resource is available: only when wind is blowing, wind turbines can be ramped down. The current control power market design constitutes a significant barrier to VRE participation, since it requires providing PC and SC for a full week. Over that time horizon, wind forecasts are very uncertain, and only rarely wind conditions are stable during such a long time. Shorter program time units are necessary to allow wind to enter this market.

In the case of solar power, in addition to the weekly auction another detail of the market design prevents participation: solar power is available in large amounts between 10 a.m. and 18 p.m. However, current market rules require PC to be provided as a base product and SC in peak (8 a.m. to 8 p.m.) and off-peak blocks. Shorter dispatch intervals are a necessary condition for solar power to supply these services.

4.5. Policy Recommendations

To improve economic efficiency and allow VRE to participate in the market, we propose a number of smaller changes to the control power market design.

More frequent auctions and shorter program time units would allow VRE generators to enter this market, and would also improve efficiency of thermal plant dispatch. Just (2010) and Müsgens et al. (2012) show that independently of VRE, shorter auction periods increase economic efficiency.

Specifically, we believe that daily auctions in steps of hours, as already implemented in the day-ahead sport market auction, would be a good solution. The cost of such reform would be transaction costs, which could be greatly reduced if the same bidding infrastructure for both markets would be used. This could imply using a power exchange instead of a proprietary platform for procurement.

If that is done, a logical next step could be to allow conditional bids for control power. Conditional joint bids on spot and control power markets, for example bidding on negative control power markets for those hours only where plants are in the money. This would mainly increase dispatch efficiency of plants that are at the money, and is not important for VRE. All three measures, daily auctions, hourly intervals, and conditional bids, would reduce control power-induced must-run of thermal plants, helping to prevent dramatic price drops in windy hours and thereby helping to mitigate the market value drop of variable renewables (Hirth 2013).

[9] List of prequalified bidders, retrieved January 27, 2013.

Alternatively or in addition, energy bids could be accepted after the capacity auction is closed, as already done in Denmark (energinet.dk 2008) and The Netherlands (TenneT 2011). TenneT argues that this feature is a key reason for lower balancing costs in The Netherlands than in Germany.

Summing up this section, we find two important results. Firstly, the prices for control power in Germany and the overall costs of control power provision decreased continuously since 2009. The costs for reserve capacity decreased by half. Moreover, control power is a very small component of the total costs of power supply: about 2% of the wholesale energy market or 0.3% of retail consumer prices. Secondly, while wind and solar power are well suited to provide negative control power during times they generate electricity, current market design in Germany impedes wind and solar power generators to supply this service. While market design reforms were successful to attract entry of new players, the current auction design continues to constitute a prohibitive entry barrier for VRE.

5. Imbalance Settlement: Imbalance Prices and Cost Allocation

We use “imbalance settlement” or “imbalance market” as an umbrella term for processes in the balancing system that take place ex post (after activation of control power). This involves two closely connected steps: the determination of the imbalance price (*Ausgleichsenergiepreis*) – the price that BRP have to pay for being out-of-balance; and the allocation of remaining costs or profits.

The imbalance price is crucial for economic efficiency, since it is the incentive for BRP to keep their portfolio balanced. A too low imbalance price leads to underinvestment in forecasts and adjustments of BRP schedules and a too high imbalance prices leads to overinvestments.

The imbalance price is not identical with the control power capacity price (the price suppliers receive for reserving capacity) or energy price (the price they receive when being activated).

5.1. Imbalance Settlement Systems

Vandezande et al. (2010) and Borggrefe & Neuhoff (2011) discuss different types of balancing settlement systems. ENTSO-E (2012a) provide an overview of balancing mechanisms and price determination in Europe. Van der Veen & Kakvoort (2010), van der Veen et al. (2010) and TenneT (2011) compare the German and the Dutch settlement systems. Elexon (2013) describes the UK system.

Usually, imbalanced BRPs that are on the “wrong” side (increase the control area imbalance) pay an imbalance price that is higher than the corresponding day-ahead price, while BRPs that are on the “right” side (decrease the control area imbalance) pay a price that is lower or receive a payment.

In practice, one can observe a large number of pricing mechanisms. They can be differentiated along several dimensions:

- Two-price v. one-price systems: In one-price systems short BRPs pay the same price per MWh that long BRPs receive. In two-price systems these prices are differentiated, for example by a punitive mark-up for BRPs that increase the system imbalance.
- Price based on the costs for control power v. price based on spot price.
- Price based on the costs of activating control power v. price based on the costs of both capacity reservation and activation.
- Price based on the average costs of control power activation v. price based on the marginal cost.
- Price based on costs v. prices that include punitive mark-ups.

- Dynamic v. static prices: static prices follow one price formula, dynamic prices follow different formulas, for example ad-hoc mark-ups during critical situations.
- The same price for all BRPs v. a differentiated price for generators and loads.

Economic efficiency suggests that the imbalance price should follow a one-price system that represents the marginal costs of both capacity reservation and activation, that is paid by all BRPs and does not contain any ad-hoc or punitive components.

The cost of capacity reservation, if not allocated via imbalance prices, is usually socialized via grid fees (ENSTO-E 2012).

5.2. Imbalance Prices and Cost Allocation Mechanism in Germany

Just as control power market design, the German imbalance pricing mechanism is regulated by the Bundesnetzagentur and has been adjusted several times during the past years. The latest reform came into force in December 2012.

Since May 2010, there is a common imbalance price for the for German control areas (*reBAP*). The German imbalance price system is a one-price system, based on the average costs of control energy, and settled for time intervals of 15 minutes, corresponding to BRP schedules (Consentec 2012, ENTSO-E 2012a). The system is designed to be cost-neutral in the sense that all costs for control energy are paid for by unbalanced BRPs. Capacity costs are not allocated via the imbalance price, but added to grid fees. Because suppliers of control power receive different energy payments (pay-as-bid), the energy price paid to any activated supplier of control power is in general different from the imbalance price.

Figure 17 displays all 70.000 quarter-hourly imbalance prices for the years 2011 and 2012 as a function of the corresponding system imbalance. It also displays the average imbalance price and the imbalance spread, the imbalance price minus the corresponding day-ahead price. As expected, there is a positive correlation between system imbalance and imbalance price.

The system does provide an economic incentive to stabilize the German supply-demand balance: when the German system was long, long BRPs lost 50 €/MWh (negative imbalance spread), since they had paid 46 €/MWh on the day-ahead market, and received -4 €/MWh as imbalance price. In times of shortage, the imbalance spread was 61 €/MWh, since short BRPs had to pay 109 €/MWh as imbalance price while the day-ahead price was 48 €/MWh. In less than one percent of all quarter hours the imbalance spread provided a perverse incentive to BRP, being negative in times of system undersupply or positive in times of system oversupply.

Surprising however, the imbalance price was on average only 40 €/MWh, while the day-ahead spot market price was 47 €/MWh. Hence, during these years, it would have been profitable (albeit unlawful) for a BRP to be constantly short (Table 7). Hence, in 2010/11 the imbalance market and the day-ahead market were not free of arbitrage opportunities.

Apparently the regulator perceived the imbalance spread as too low to provide a sufficiently strong incentive for BRP to avoid imbalances (Bundesnetzagentur 2012a). As a consequence, a punitive mark-up was introduced in late 2012. Since then, the price includes a mark-up of at least 100 €/MWh if more than 80% of all control power is activated – however, in 2010/11, this happened only in 0.5% of all quarter hours.[10] The revenues generated during those times are distributed to consumers via reduced grid fees.

[10] Bundesnetzagentur BK6-12-024, www.bundesnetzagentur.de/DE/DieBundesnetzagentur/Beschlusskammern/1BK-Geschaeftszeichen-Datenbank/BK6/2012/BK6-12-001bis100/BK6-12-024/BK6-12-024_Beschluss_2012_10_25.pdf

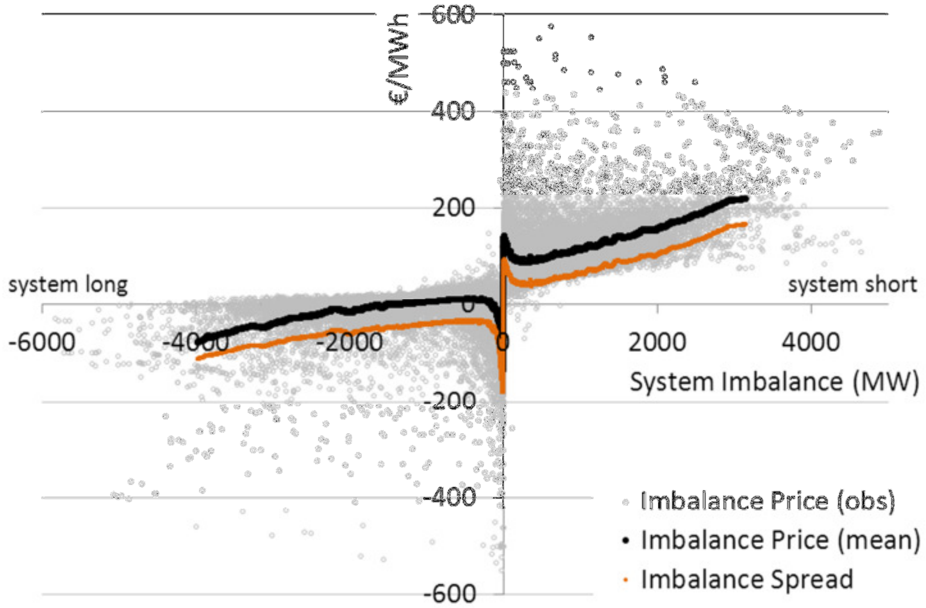


Figure 17. German system imbalance and imbalance price 2011-12 (70.000 quarter-hourly observations). At an imbalance of 2000 MW (positive control power activated), the imbalance price was 150 €/MWh on average, 100 €/MWh above the corresponding day-ahead spot price.[11]

Table 7: Imbalance prices and incentive to BRPs

	Average	System long (60% of all hours)	System short (40% of all hours)	System very long (<-2000MW) (4% of all hours)	System very short (>2000MW) (2% of all hours)
Imbalance price*	40 €/MWh	-4 €/MWh	109 €/MWh	-32 €/MWh	186 €/MWh
Day-ahead price*	47 €/MWh	46 €/MWh	48 €/MWh	41 €/MWh	52 €/MWh
Imbalance spread* (penalty for short BRP)	-7 €/MWh	-50 €/MWh	61 €/MWh	-73 €/MWh	134 €/MWh

*Time-weighted average.

In 2011, the net costs of activating regulating energy were € 200 million, and in 2010 to € 300 million.[12] Balancing energy is surprisingly cheap: divided by total electricity consumption, costs are not more than 0.5 €/MWh. This equals about 40% of the costs of reserving capacity, 1% of the size of the wholesale market, or less than 0.2% of households' electricity bill. An important reason why net costs are so small is that costs for activating upward regulating balances with income for activating downward regulation.

The German TSOs publish imbalance prices and the cost of imbalance energy only with a backlog of several months. Because of the long time until settlement, BRPs trade imbalances to cancel out individual imbalances on the so-called "day after" market. In a one-price system this does not affect expected costs; it is only done to reduce uncertainty.

Of the four TSOs, only 50Hertz publishes data on the financial flows between imbalanced BRPs. In 2011, unbalanced BRP were charged € 120 million, of which € 90 million were distributed to other (counter-balanced) BRPs and € 30 million used for activating control power. In 2010, financial flows

[11] www.amprion.net/ausgleichsenergiepreis; www.epexspot.com
[12] www.tennettso.de/site/Transparenz/veroeffentlichungen/bilanzkreise/finanzielles-gleichgewicht/finanzielles-gleichgewicht; www.amprion.net/finanzielles-gleichgewicht; www.transnetbw.de/strommarkt/bilanzkreismanagement-und-bilanzkoordination/finanzielles-gleichgewicht/; www.50hertz.com/de/1928.htm

were comparable. If 50Hertz data can be scaled up, German BRPs pay about € 750 million per year for being out-of-balance, of which about three quarters are recycled to other BRPs.

The imbalance price is based only on costs of activating capacity. The costs for control power reservation, however, are distributed to all electricity consumers on a pro-rata (€/MWh) basis.

5.3. The Balancing Price as Incentives for Accurate VRE Forecasts

TSOs and regulators often view the imbalance price primarily from a cost allocation perspective: the price is set in a way that the costs of control power are allocated and no profits or losses remain with the system operators. However, from an efficiency perspective, the crucial role of the imbalance price is that it constitutes the incentive to BRPs to avoid imbalances.

All BRPs have the possibility to reduce their imbalance, for example by means of more accurate and more frequent forecasts, shifting from hourly to 15 min scheduling, and more active intra-day trading. All these measures are costly. Alternatively, they are facing the imbalance price. Rational BRPs invest only in such imbalance management measures as long as the marginal costs of reducing their imbalances are lower than the imbalance price.

For static and dynamic efficiency, the imbalance price should reflect the marginal economic costs of solving imbalances by means of control power. In the welfare optimum, these marginal costs are identical to the marginal costs of avoiding imbalance by means of better forecasting and intra-day balancing.

While this is true for all sources of imbalance (section 3.1), it might be especially relevant for wind and solar power. Relative to their output, imbalances are larger than for other generators. In addition, forecasting methodology is relatively young and progressing quickly. Both for static and dynamic efficiency it is important that VRE generators see the true costs of forecast errors via unbiased price signals.

Until early 2012, German VRE generators were shielded from the costs of forecast errors, since they were granted a fixed remuneration under the feed-in-tariff. In 2012, an optional feed-in-premium was introduced which opened the possibility of supplying control power, but also exposed generators to imbalance costs and hence for the first time provided strong incentives to improve forecasts.

5.4. Passive and Active Balancing

When TSOs deploy control power, they compensate suppliers with an energy payment. This is the economic incentive for activated generators to actively balance the system. Similarly, the imbalance price provides the incentive to BRPs to “passively” balance the system.

Preconditions for a functioning passive balancing incentive are on the one hand a timely publication of the imbalance price and on the other hand the legal possibilities for BRPs to unbalance their on purpose on purpose. Often imbalances last for quite a while, for example during Christmas 2011 or early February 2012 in Germany (Bundesnetzagentur 2012a). Signaling BRPs critical situations via high prices would induce self-balancing behavior and stabilize the system.

Passive balancing is an alternative to allow energy-only bids after the control power tendering process (section 4.5).

5.5. Policy Recommendations

There are three major sources of inefficiency in the German imbalance market: the long time lag until prices are published, average pricing, and the allocation of capacity costs via grid fees. We discuss each in turn.

Imbalance prices are today published with a delay of several months. This implies that BRPs do not receive a price signal when they can still respond to system imbalances. In France, Benelux, and UK prices are published within less than one hour (ENTSO-E 2012a). TenneT (2011) reports smaller imbalances in The Netherlands than in Germany and identifies the quick publication of imbalance price as one of the reasons. We propose to publish imbalance prices as close to real time as possible, latest within one hour.

Economic theory suggests the imbalance price should be based on the *marginal* cost of control energy provision, not the average cost. The combination of pay-as-bid auctions on the control power market and average pricing on the imbalance market leads to inefficiently low imbalance prices. For efficiency, the price signal should reflect the marginal economic costs of activating control power, which is the energy bid of the last activated supplier. This could be implemented via a marginal common clearing price for activated energy, or via a marginal pricing rule for the imbalance price. The only difference between those two options is the allocation of the infra-marginal rent.

Similarly, economic theory suggests that the costs of capacity reservation should be born by those BRP that cause the need for capacity reservation. Charging BRPs economically efficiently for capacity reservation would mean, strictly speaking, to charge them only during times of extreme system imbalances (those hours that are relevant for the dimensioning of the reserve). However, it is ex ante impossible to determine which hours that would be, and hence such a pricing mechanisms seems to be unfeasible. A pragmatic approach could be to allocate the costs of capital provision proportionally to imbalanced BRP via the imbalance price. The costs of positive capacity could be allocated in times of undersupply and those of negative capacity in times of oversupply. Vandezande et al. (2010) proposed a similar pricing mechanism, and, acknowledging that it is still not strictly economically efficient, even propose to avoid capacity payments when procuring control power because costs are so difficult to allocate.

Take a simple numerical example. In 2011, the costs for positive and negative capacity reservation (not including PC) were € 160 million and € 310 million, respectively. The amount of energy activated was 7 TWh and 18 TWh (Bundesnetzagentur 2012b). Allocating capacity costs via imbalance prices would have increased the gap between day-ahead prices and imbalance prices by about 20 €/MWh, both in periods of undersupply and oversupply.

Both average pricing and the allocation of capacity costs via grid fees cause the imbalance price to be inefficiently low[13] and hence constitute a positive externality. Hence, BRPs receive a too weak incentive to balance their portfolios. Specifically, VRE generators have a too weak incentive to forecast accurately.

As a consequence of higher imbalance prices, we expect markets and technology to respond. More accurate scheduling will be more profitable. Hence, 15 min intraday markets will become more liquid and widespread. Both VRE and load forecasts will become more precise. Together, this will reduce both utilization of control power and reserve requirements.

Summing up the results from this section, we suggest that balancing settlement systems should provide correct price signals to BRP. Because imbalances of VRE are larger, and because wind and solar forecasting are relatively new technologies, correct incentives to VRE are especially important from a static and dynamic welfare perspective. Therefore, the balancing prices should be a one-price system without punitive charges, based on the marginal costs of control energy deliver, and include

[13] More precisely, the price deviation between spot prices and imbalance prices is too small. Imbalance prices in times of scarcity are too low and imbalance prices in times of oversupply are too high.

the costs of control power provision. In Germany, the imbalance price is currently inefficiently low, because it is based on the average cost of control energy, and does not include the costs of capacity reservation. Furthermore, the imbalance price should be published close to real time to incentivize passive balancing.

6. Balancing Systems in Other Regions

While the fundamental physical challenges of system balancing are the same in all power systems, the types of control power differ in terminology and technical specifications. There are a few studies that compare systems: ENTSO-E (2012a) provides an overview of control power types in the UCTE and other European synchronous systems. Rebours et al. (2007a) and Ela et al. (2011a) compare UCTE control power to American balancing systems and help a lot clarifying terminology. In the following, we briefly discuss the Nordic and American approach to balancing and identify elements that could improve German system.

6.1. Nordel

The synchronous system of Nordel covers Norway, Sweden, Finland, and the Eastern part of Denmark. Its balancing system and control power market is surveyed by Kristiansen (2007) and Bang et al. (2012).

There are four types of control power: primary regulating power, fast active disturbance reserve, fast active forecast reserve, and slow active disturbance reserve. Primary regulating power is comparable to PC, the two “fast” reserves are comparable to SC and the “slow” reserve to TC.

A common market was established in 2001, which means that trading can take place between TSOs. For example, one third of primary regulating power can be imported, but the contract is established between importing and exporting TSOs. Suppliers of control power always deliver to the TSO of their control area.

However, neither control power nor imbalance market design is uniform across countries. While in Denmark, the TSO procures reserves in pay-as-bid auctions, the other three TSOs use a marginal clearing price. In most markets, reserves are tendered in yearly, weekly, or daily auctions, but suppliers can adjust their bids until close to real time. While primary regulating power is remunerated with a capacity payment, it is only in Denmark that the suppliers of the other types receive a capacity price. Additional suppliers can bid after the tender, in which case they receive energy payments only (energinet.dk 2008, Kristiansen 2007).

Imbalance settlement follows a one-price system in Norway, while in the other countries two-price systems are in place for generators and one-price systems for loads. Loads are always settled with the imbalance (“regulation”) price. Generators that reduce the system imbalance are priced with the day-ahead spot price, while generators that increase the system imbalance pay the imbalance price. However, if generators update their schedules up to one hour prior delivery, they fall under the one-price regime as well. The imbalance price in the five bidding areas in Norway and the four areas in Sweden is different if transmission capacity is constrained. Bang et al. (2012) report price data that show that the imbalance prices are quite close to spot prices, with an average imbalance spread of less than 5 €/MWh.

6.2. United States

In many U.S. systems, control power is set up quite differently. In markets such as ERCOT/Texas, CAISO/California, NYISO/New York, or PJM, plants are dispatched centrally by an independent system operator (ISO). Unit commitment, dispatch, and control power is optimized jointly “in one go” subject to transmission constraints. Those markets are characterized by nodal pricing and high-resolution (typically 5 min) real-time markets. For a broader discussion of that market model see Schweppe et al. (1988), Hogan (1992), Morey (2001), O’Neill et al. (2006) and Pollitt (2012). Morey (2001) and Ela et al. (2011a, 2011b) provide good overviews of American control power markets.

In continental Europe, reserve requirements are regulated by the UCTE (2009), in the U.S. by the North American Electric Reliability Council (NERC 2012). American ISOs determine the regulation requirement usually as a share of peak load or as a percentile of reserves utilized under comparable conditions in terms of season and day of the week. The contingency reserve is set to cover the largest credible contingency (ERCOT 2010, Ela et al. 2011b).

In ISO systems, control power provision is typically co-optimized with dispatch. Because of high-frequency economic dispatch, the need for operational reserves is significantly lower than in Europe. While UCTE control power is used as operational and contingency reserve, American systems distinguish between those services. The types of control power traditionally used in these systems are called “governor response”, “regulation”, “spinning reserve”, “non-spinning reserve”, and “replacement reserve”. Governor response is a frequency-sensitive adjustment of output comparable to PC, but usually not remunerated. Regulation is a symmetric product, while the other reserves are only upward-regulation. Spinning and non-spinning jointly is regarded as “contingency reserve.” Regulation and spinning reserve are comparable to SC while non-spinning and replacement reserve to TC. The details of technical definitions vary across systems. (Hirst 2000, Ela et al. 2011a, 2011b).

Most ISOs procure capacities in a “rational buyer model” or a “smart buyer model”, where suppliers bid for all types of reserves at once and the ISO minimizes total costs of reserve provision (Morey 2001, Ela et al. 2011b). Suppliers typically receive a marginal capacity prices, and the real-time energy prices if activated. Regulation usually is only remunerated with a capacity payment. The cost of capacity procurement is socialized on consumers. Imbalanced market actors have to pay that energy price.

6.3. Lessons to Learn

The Nordic balancing system is relatively similar to UCTE and German setup. In two areas Nordel could serve as a role model: TSO cooperation and flexible control power market design. Specifically, allowing to adjust energy bids after the capacity tender, and allowing energy bids of suppliers that did not win the capacity auction, would help more generators to participate in control power markets.

The American setup, being part of a fundamentally different electricity market design, is quite distinct from the German balancing system. It shows that (very) short dispatch intervals greatly reduce the need for control power, and that joint procurement of control power along the lines of the “smart buyer model” is economically beneficial.

7. Conclusions and Policy Recommendations

In this paper, we have compiled a broad overview of the German balancing system, and discussed the role and impact of variable renewables on them.

Four important findings emerge from this study. Firstly, the required amount of reserved capacity depends on a multitude of factors. Wind and solar power forecast errors power are only one of several important drivers. Secondly, the empirical correlation between reserved capacity and installed wind and solar capacity is weak. Specifically, German control power reserves were reduced by 20% between 2008 and 2012 and costs by 50%, despite a doubling of VRE capacity during that time (Figure 18). Thirdly, the design of control power markets determines the incentives for VRE generators to provide control power themselves. Finally, the design of imbalance markets determines the incentives for BRPs for balancing their portfolios. Specifically, it sets the incentives for VRE generators to forecast accurately.

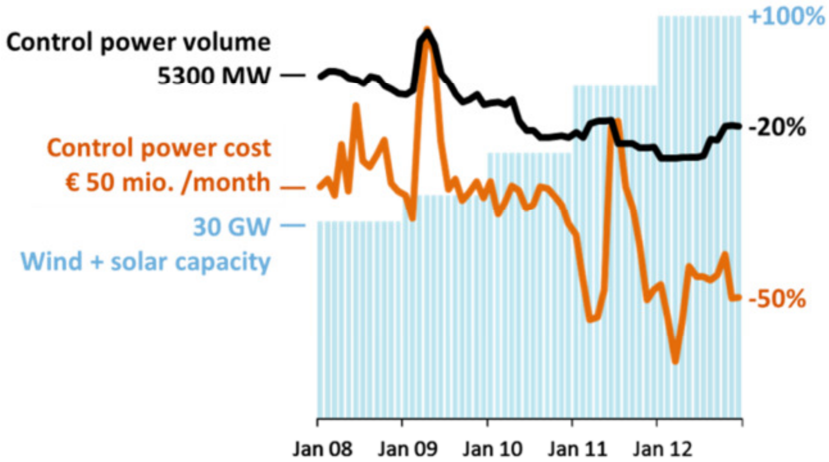


Figure 18. VRE capacity, reserves, and costs of control power.

These findings lead to a number of policy recommendations (Table 8).[14] In the control power market, entry barriers for variable renewables should be lowered to stimulate market entry. Specifically, we recommend to shift to daily auctions, and to reduce the time interval during which capacity has to be reserved to one hour, in line with day-ahead spot market. To reduce transaction costs and to allow conditional bids, procurement via the power exchange seems to be sensible. Moreover, we recommend switching from pay-as-bid to marginal pricing.

In the area of imbalance settlement, we emphasize the role of the imbalance price as price signal. Today, the imbalance price is often understood as a cost allocation mechanism, but we regard its role as economic incentive to BRPs as most important. Therefore, the price should be published close to real time. Moreover, we recommend to include the costs of capacity reservation in the imbalance price.

All these proposals affect VRE if and only if they are operating under the new feed-in-premium. Wind and solar generators under the old feed-in-tariff are not allow participating in the control power market, and are not obliged to pay for imbalance. Hence, any reform of the balancing system would be more effective if the remaining generators would be incentivized or forced to switch to the feed-in-premium.

[14] In general, we see significant efficiency potentials in international cooperation and market integration. Since these questions are widely discussed in the implementation process of the European target model (section 2.6) and regional TSOs cooperation initiatives (3.3), we restrict our recommendations to evolutionary developments of the German markets design.

Table 8: Policy proposals.

	Proposal	Intended Effect
Control power	Tender PC and TC daily (today weekly)	Allow wind and solar market participation (SC$^-$, TC$^-$)
	Reduce contract duration to hours (today blocks of four hours or peak/off-peak)	Allow wind and solar market participation (SC$^-$, TC$^-$)
	Marginal pricing (today pay-as-bid)	Cost-based bidding
	Smart buyer model / common auction for PC/SC/TC (today separate auctions)	More efficient resource allocation
	Dynamic and price-elastic reserve dimensioning (today static and price-inelastic)	Higher security level at reduces capacity costs
Imbalance	Publish imbalance price within one hour (today months later)	Provide price signals to BRP when they are able to respond
	Marginal pricing (today average with mark-up) (obsolete if marginal pricing is introduced in control power markets)	Economically efficient price signals to BRP
	Allocate costs of capacity reservation via imbalance prices (today grid fees)	Economically efficient price signals to BRP

This leaves us with two high-level conclusions. On the one hand, it seems to be possible to add even significant amounts of variable renewables to power systems without necessarily affecting the costs of control power provision dramatically. Control power supply does not seem to be a major issue for wind integration, at least not during the coming years. On the other hand, in Germany and elsewhere a lot can be done to improve incentives by changing the market design of control power markets and imbalance settlement systems.

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