Incentive Compatible Imbalance Settlement

Tobias W. Haring, *Student Member, IEEE*, Daniel S. Kirschen, *Fellow, IEEE*, and Göran Andersson, *Fellow, IEEE*

***Abstract*—Imbalance settlement markets are managed by the system operators and provide a mechanism for settling the inevitable discrepancies between contractual agreements and physical delivery. In European power markets, settlements schemes are mainly based on heuristic penalties. These arrangements have disadvantages: First, they do not provide transparency about the cost of the reserve capacity that the system operator may have obtained ahead of time, nor about the cost of the balancing energy that is actually deployed. Second, they can be gamed if market participants use the imbalance settlement as an opportunity for market arbitrage, for example if market participants use balancing energy to avoid higher costs through regular trade on illiquid energy markets. Third, current practice hinders the market-based integration of renewable energy and the provision of financial incentives for demand response through rigid penalty rules. In this paper we try to remedy these disadvantages by proposing an imbalance settlement procedure with an incentive compatible cost allocation scheme for reserve capacity and deployed energy. Incentive compatible means that market participants voluntarily and truthfully state their valuation of ancillary services. We show that this approach guarantees revenue sufficiency for the system operator and provides financial incentives for balance responsible parties to keep imbalances close to zero.**

***Index Terms*—Imbalance settlement, mechanism design, public good theory.**

I. Introduction

As part of their responsibility for the reliable operation of the grid, transmission system operators (TSO) must ensure that generation and consumption remain in balance at all times. Most of the electrical energy is typically traded in forward with different time frames. However, the balancing market is crucial for the stable operation of the system because it represents the market of last resort. TSOs use markets for ancillary services (AS) to procure the resources that they deem necessary to maintain this balance. The AS market interacts with the energy markets because the AS resources are deployed in real time to produce or consume energy [1]–[4]. For example, in the electricity markets of continental Europe, the trades reported by the Balance Responsible Parties (BRPs) must be combined with the deployed energy from the AS resources in the imbalance settlement process. BRPs are made responsible for keeping their own portfolio balanced over a given timeframe (i.e., the settlement period). Each market participant can decide for itself whether to become a BRP, or be part of one. In this paper, we examine how the determination of the needs for AS, the rules governing the procurement of these resources, and their deployment interact with the operation of the balancing market and with the other stages of the energy market.

Several authors have already highlighted design shortcomings in some of these markets [5]–[7]. First, the remuneration of costs of AS capacity and of the deployed balancing energy is often not transparent because it mixes prices from the energy markets with penalties that are not market-based. Remaining costs are socialized through grid tariffs. Second, these markets typically do not respect the principle of cost causality, because they do not include a locational component and do not price the reliability of the energy supply according to the willingness to pay. Third, if the imbalance settlement does not rely on market-based prices, participants may game the system for their own benefit. For example, market participants may find it beneficial to shift demand from the energy spot markets to the imbalance market if energy prices are predictably lower on this market. On the other hand, if imbalance prices are too high, generators may withhold capacity from the energy market to avoid any imbalances in real-time. Both processes reduce the liquidity of the energy market and provide opportunities to exploit market power. Fourth, well-functioning intra-day and balancing markets are beneficial for an economically efficient integration of stochastic renewable energy sources [7]. A market-based pricing of these imbalances would indeed reflect the true cost that these resources impose on the system. However, BRPs with a large share of fluctuating renewable energy injections should not be penalized per se for deviations from their schedule but rather according to their efforts to mitigate or avoid these fluctuations.

We argue that an economically efficient mechanism, where efficiency comes in several dimensions as highlighted in [8], for settling AS capacity and balancing energy should be based on the following principles:

1) It should cover the costs of the different types of AS capacity.
2) It should reflect the locational value of AS capacity when the grid is heavily loaded.
3) Charges should be based on the individual valuation of system services.
4) System participants who create imbalances should pay more to give them an incentive to invest in means of reducing imbalances, such as storage and demand response.
5) It should not include energy market components to avoid gaming opportunities.

It is shown that "market-like" solutions for imbalance settlement can be achieved, which support different forms of market efficiency. For example, efficiency in production, which means that the products with the lowest factor input costs are produced,

Manuscript received July 14, 2014; revised October 23, 2014; accepted December 18, 2014. Date of publication January 27, 2015; date of current version August 03, 2015. Paper no. TPWRS-00958-2014.

T. W. Haring and G. Andersson are with the EEH—Power Systems Laboratory, ETH Zurich, 8092 Zurich, Switzerland (e-mail: tharing@eeh.ee.ethz.ch; andersson@eeh.ee.ethz.ch).

D. S. Kirschen is with the Department of Electrical Engineering, University of Washington, Seattle, WA 98195 USA (e-mail: kirschen@uw.edu).

Color versions of one or more of the figures in this paper are available online at http://ieeexplore.ieee.org.

Digital Object Identifier 10.1109/TPWRS.2014.2387947

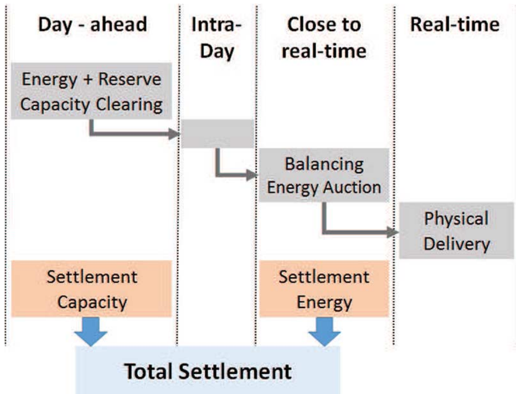


Fig. 1. Proposed imbalance settlement mechanism.

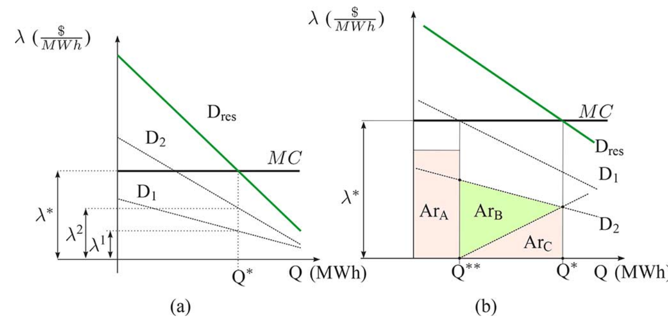


Fig. 2. Market clearing for public and private goods and constant marginal costs of supply: (a) Public good clearing: The demand curves D_1 and D_2 are added vertically (D^*_{res}) to achieve a Lindahl equilibrium (λ^*, Q^*). The individual price shares are λ^1 and λ^2, (b) Groves-Clarke Mechanism in case of linear demand and constant marginal costs of supply: The contribution of demand curves D_1 and D_2 on the market outcome is calculated separately. The individual gets charged the area Ar_A and Ar_C. Ar_B represents the benefit of the BRP of consuming the public good.

is achieved when the BRPs start to reduce their demand for AS capacity and energy in such a way that they reduce their share to pay for the total system costs incurred through their imbalances. Efficiency in allocation, which means that only those goods are produced which have the highest demand, is achieved through different demand-curves for different sorts of reserves. Finally, the whole framework serves dynamic efficiency, since it produces market-based outcome where changes in the environment can be internalized in a pricing mechanism. Other approaches do not ensure this efficiency because they include socialization of costs and therefore in the end no "demand" for AS capacity or deployed energy. In the end the consumer benefits from lower prices through a market-like framework which is less prone to gaming. Using the principles of mechanism design and public good theory [9], we have developed the settlement mechanism shown in Fig. 1. This design includes charges for both, AS capacity and deployed energy, and takes into account locational price differences. It achieves transparent cost remuneration and provides incentives for truthful disclosure of stated preferences regarding AS capacity and balancing energy. In this paper, it is assumed that estimations about preferences do exist. Reference [10] already indicated this issue for the case of utilities which estimate demand functions of customers for reliable electricity supply. Charges for non-event-based AS capacity are calculated using a Ramsey-type rule [11], [12]. This means that the reserve capacity is a function of the individual elasticity of demand [6], [13]. Additional fairness considerations, which modify the Ramsey-rule, e.g., [14] and [15], are not considered in this paper. To encourage a reduction in imbalances deviations, balancing energy costs are recovered using a real-time market for balancing energy.

The authors of [16] highlight design issues of a market for energy imbalances based on real-time prices signals, such as the real-time dispatch methodology, the ancillary service auctions, and the settlement. References [17] and [18] stress the necessity of a reliability differentiated real-time pricing in order to achieve efficient market outcomes. A mostly descriptive discussion of the need for proper imbalance pricing based on market based components can be found in [1] and [2]. The authors of [6] and [19] develop a game theoretic framework to analyze the possible negative consequences of suboptimal incentive mechanisms in the balancing market. Reference [20] investigates the possibilities for strategic behavior in the Nordic balancing market using an agent-based model. The authors of [21] and [22] apply a cost-based methodology for the valuation of AS capacity and balancing energy and allocate fixed and usage costs using a non-linear tariff system.

The remainder of this paper is organized as follows. Section II describes the proposed pricing mechanism methodology. Section III assesses the influence of the design parameters of this pricing framework using a simulation model and compares the proposed approach to a benchmark. Section IV concludes the paper and outlines further work.

II. Description of the Proposed Settlement Mechanism

A. Overview

Fig. 1 puts the proposed settlement mechanism in the context of the electricity market. As discussed in [23] and [24], many different types of AS have been defined in different markets. For the clarity of the exposition, we will consider only two types of AS: non-event-based AS represents the capacity held in reserve to balance the system under normal conditions and includes regulating reserve. On the other hand, event-based AS is the capacity provided to protect the system against outages of power plants and interconnections and is typically called contingency reserve [23], [24]. Energy as well as event-based and non-event-based reserves are traded on a day-ahead basis and the prices for these ancillary services are settled. After the closure of an optional intraday market, the real-time balancing market determines the price of short-term balancing energy. BRPs take part in this process because they need non-event-based AS capacity and balancing energy to compensate for deviations between their scheduled and their actual performance, particularly if they operate stochastic renewable energy sources. Balancing serving parties (BSPs) provide balancing energy and ancillary services to the TSO. The TSO determines the amount of AS capacity it needs based on security standards and procures this AS capacity and the required balancing energy in single buyer auctions. The BRPs get charged the costs of AS capacity on the basis of a non-linear pricing scheme, which differentiates between the costs of event-based and non-event-based AS. Each BRP requires a different amount of balancing energy and this amount is determined in part by the amount of flexible resources (e.g., fast ramping generation, storage, and demand response) that it can muster.

B. Determining the Cost of AS Capacity

For the achievement of a consistent set of prices for energy, reserves and corresponding quantities, energy and reserves are in this framework co-optimized in a day-ahead auction with regards to minimization of procurement costs and lost opportunity costs of generators [25]. However, the framework also supports the separate clearing of energy and AS capacity. BSPs are assumed to bid for the provision of AS using piecewise-linear cost curves. Certain assumptions are made with regards to the parametrization:

1) The event-based AS capacity requirements are modeled as a share p of total generation capacity at a given time. As an alternative, the largest generation unit in operation may be taken as an deterministic rule.
2) We use chance-constraints to determine probabilistically the amount of up and down non-event-based AS capacity required [26]–[28]. Thereby, we assume that a high percentage of normally distributed deviations from the schedule are covered by reserves.

Both assumptions influence the model since costs of reserves rise along with rising requirements. However, other forms of determination of reserve requirements are conceivable. The main issue is that the TSO is compelled to procure only the necessary amounts of reserves to remain system security. Doing so, we show in the following how the TSO gets fairly close remunerated the costs of remaining system security.

C. Allocation of AS Capacity Cost

We follow [12] to achieve an incentive compatible charge for capacity. We use the primal market outcome from the co-optimization problem and calculate the optimal two-part capacity charge for event-based and non-event-based AS, which ensures sufficient revenue for the TSO as a monopolistic service provider. The costs that the TSO has to cover are the procurement cost of the event-based AS capacity, $C_{\text{cap}}^{\text{evt}}$, the costs of non-event-based capacity, $C_{\text{cap}}^{\text{noevt}}$, and additional commitment costs, $C_{\Delta\text{commit}}$. The change in the commitment costs results from the difference between commitment costs from the co-optimization of energy and reserves as compared with an energy-only unit commitment problem. This has consequences in case of an unflexible generation portfolio where additional commitment costs can be very high [29]. For brevity we only state the problem formulation for up-AS capacity. The formulation is similar for down-AS capacity. The BRP j is assumed to have a willingness to pay for non-event-based AS capacity at time t, $B_{\text{cap}}^{j,t}$, of the form

$$B_{\text{cap}}^{j,t} = a^{j,t} + b^{j,t} Q_{\text{cap}}^{j,t} - c^{j,t} {Q_{\text{cap}}^{j,t}}^2 \tag{1}$$

where $a^{j,t}, b^{j,t}, c^{j,t} > 0$, and $Q_{\text{cap}}^{j,t}$ is the quantity of non-event-based AS capacity demanded by BRP j at time t. Because this function is concave, the benefit of the BRP from relying on system services provided by the TSO decreases. In other words, the BRP has a diminishing demand for externally provided flexibility resources either because of a low valuation of possible outages, flexible demand processes, or due to the installation of onsite backup capacity. The derivative of (1) with respect to $Q_{\text{cap}}^{j,t}$ is

$${MB_{\text{cap}}^{j,t}}^{-1} = \frac{dB_{\text{cap}}^{j,t}}{dQ_{\text{cap}}^{j,t}} = b^{j,t} - 2c^{j,t} Q_{\text{cap}}^{j,t}. \tag{2}$$

A reformulation of (2), with $(dB_{\text{cap}}^{j,t})/(dQ_{\text{cap}}^{j,t}) = \lambda_{\text{cap}}^{t}$ gives

$$MB_{\text{cap}}^{j,t} = Q_{\text{cap}}^{j,t} = \frac{b^{j,t}}{2c^{j,t}} - \frac{\lambda_{\text{cap}}^{t}}{2c^{j,t}}. \tag{3}$$

Equation (2) states the inverse marginal willingness to pay for AS capacity as a function of the quantity demanded, MB_{cap}^{-1}. On the other hand, (3) shows the marginal willingness to pay for capacity, $MB_{\text{cap}}^{j,t}$, as a function of price for up-reserve capacity at time t, λ_{cap}^{t}. We use a stepwise approximation of (1), (2), and (3). We define sets of indices $v = \{j,t\}, v' = \{j',t\}, w = \{j,t,k\}, w' = \{j',t,k\}$. The indices j, k, and t refer to BRP j, time interval t, and segment k of the piecewise linear curve, respectively. j' refers to all other BRPs except j. The problem of cost allocation in case of AS capacity is stated as a weighted maximization of the profit of the TSO and the wealth of the BRPs, $SU^{j,t}$:

$$\begin{aligned} \max_{\boldsymbol{\vartheta_1}} \cdot \sum_{t=1}^{N_{\text{T}}} \Bigg\{ (1-\beta) \Bigg[\sum_{j=1}^{N_{\text{BRP}}} \sum_{k=1}^{N_{\text{K}}} (p_{\text{var}}^{w} - {p_{\text{var}}^{*}}^{w} \\ - \left(\left(\lambda_{\text{cap}}^{t} M_{\text{BRP}}\right)' \mathbf{1}^{\boldsymbol{K}} \right) \times u^{w} \Big) \times MB_{\text{cap}}^{w} + p_{\text{fix}}^{v} \Bigg] \\ + \beta \sum_{j=1}^{N_{\text{BRP}}} SU^{j,t} \Bigg\} \end{aligned} \tag{4}$$

subject to a no-loss constraint for the TSO:

$$\begin{aligned} \sum_{t=1}^{N_T} \Bigg\{ \Bigg[\sum_{j=1}^{N_{\text{BRP}}} \sum_{k=1}^{N_{\text{K}}} \Big((p_{\text{var}}^{w} - {p_{\text{var}}^{*}}^{w}) - \Big(\left(\lambda_{\text{cap}}^{t} M_{\text{BRP}}\right)' \mathbf{1}^{\boldsymbol{K}} \Big) \times u^{w} \Big) \Bigg] \\ \times MB_{\text{cap}}^{w} + p_{\text{fix}}^{v} \Bigg] - C_{\text{fix}}^{t} \Bigg\} \geq 0. \end{aligned} \tag{5}$$

The wealth of the BRPs is determined by

$$\begin{aligned} \sum_{t=1}^{N_{\text{T}}} \sum_{k=1}^{N_{\text{K}}} \left\{ B_{\text{cap}}^{w} \times u^{w} - (p_{\text{var}}^{w} - {p_{\text{var}}^{*}}^{w}) \times {MB_{\text{cap}}}^{w} \right\} \\ - p_{\text{fix}}^{v} \geq SU^{j,t}, \forall j, s. \end{aligned} \tag{6}$$

Further, it has to be ensured that the amount of procured reserves is matched with the demand:

$$\sum_{j=1}^{N_{\text{BRP}}} \sum_{k=1}^{N_{\text{K}}} {MB_{\text{cap}}}^{w} \times u^{w} \geq R_{\text{Req}}^{\text{noevt},t}, \forall t. \tag{7}$$

Incentive-based payments are ensured via

$$\begin{aligned} \sum_{t=1}^{N_{\text{T}}} \sum_{k=1}^{N_{\text{K}}} \left\{ B_{\text{cap}}^{w} \times u^{w} - (p_{\text{var}}^{w} - {p_{\text{var}}^{*}}^{w}) \times {MB_{\text{cap}}}^{w} \right\} - p_{\text{fix}}^{v} \\ \geq \sum_{t=1}^{N_{\text{T}}} \sum_{k=1}^{N_{\text{K}}} \left\{ B_{\text{cap}}^{w'} \times u^{w'} - \left(p_{\text{var}}^{w'} - {p_{\text{var}}^{*}}^{w'} \right) \times {MB_{\text{cap}}}^{w'} \right\} \\ - p_{\text{fix}}^{v'}, \forall j, k, t. \end{aligned} \tag{8}$$

Constraints (9)–(13) are necessary for using the right segment on the piecewise cost curve:

$$\sum_{k=1}^{N_{\mathrm{K}}} u^{w} \leq 1, \forall j, t \tag{9}$$

$$p_{\mathrm{var}}^{w} - {p_{\mathrm{var}}^{*}}^{w} \leq \sum_{k} {MB_{\mathrm{cap}}^{-1}}^{w} \times u^{w}, \quad \forall j, t, k = [1, N_K - 1] \tag{10}$$

$$p_{\mathrm{var}}^{w} - {p_{\mathrm{var}}^{*}}^{w} \geq \sum_{k} {MB_{\mathrm{cap}}^{-1}}^{w} \times u^{w}, \quad \forall j, t, k = [2, N_K] \tag{11}$$

$$0 \leq p_{\mathrm{var}}^{w} - {p_{\mathrm{var}}^{*}}^{w} \leq u^{w} M, \quad \forall j, t, k \tag{12}$$

$${p_{\mathrm{var}}^{*}}^{w} \leq (1 - u^{w}) M, \quad \forall j, t, k \tag{13}$$

where

$$\boldsymbol{\vartheta_1} = \{p_{\mathrm{fix}}^{v}, u^{w}, p_{\mathrm{var}}^{w}, {p_{\mathrm{var}}^{*}}^{w}\}$$

and $M_{\mathrm{BRP}} \in \mathbb{R}^{N_{\mathrm{B}} \times N_{\mathrm{L}}}, \mathbf{1}^{\boldsymbol{K}}$ is a unity vector of dimension $[1 \times N_{\mathrm{K}}], \lambda_{\mathrm{cap}}^{t} \in \mathbb{R}^{N_{\mathrm{T}} \times N_{\mathrm{B}}}$. All decision variables are greater or equal to zero. Parameters $N_{\mathrm{T}}, N_{\mathrm{K}}, N_{\mathrm{BRP}}, N_{\mathrm{B}}$ are the number of time periods, the number of segments in the stepwise curves, the number of BRPs, and the number of buses, respectively. p_{fix}^{w} refers to the fixed part of the nonlinear charge, which is not dependent on the demand of non-event-based reserves. p_{var}^{w} is the variable charge part of the cost, which is charged to BRP j for its individual demand for non-event-based AS capacity. ${p_{\mathrm{var}}^{*}}^{w}$ is an auxiliary variable, which is necessary to avoid a multiplication of binary and continuous decision variables [30]. u^{w} is a binary vector, which is used to choose between the different segment of the piece-wise linear curves. $\lambda_{\mathrm{cap}}^{t}$ is the price of the non-event-based services at N_{B} buses at time t. C_{fix}^{t} are the costs of the event driven system services. M_{BRP} is the connectivity matrix of BRP j to bus n where an element is one if the BRP j is connected to a certain bus n. The symbol $\times$ refers to an element-wise matrix multiplication.

Constraint (5) ensures that the TSO does have sufficient revenue to cover all procurement costs of system services. Constraint (6) ensures the individual rationality of the BRP is dependent upon its individual willingness to pay for event-based and non-event-based reserves. Constraint (7) ensures that the total non-event-based AS capacity that the BRPs are willing to pay for is at least equal to the quantity procured by the system operator. Constraint (8) ensures incentive compatibility so BRPs reveal their true preferences about non-event-based system services. Each BRP is therefore better off by stating its true valuation of AS capacity. Constraint (9) allows only one segment on the stepwise-linear willingness to pay functions to be active. Constraints (12)–(13) ensure that the determined variable charges are in the range of the stated demand curves for non-event-based reserves.

D. Pricing and Cost Allocation of Balancing Energy

1) Imbalance Settlement in the Real-Time Energy Market: Real-time energy balancing can be modeled as a re-dispatch at time t [16]:

$$\min_{\boldsymbol{\vartheta_2}} \cdot \sum_{i=1}^{N_{\mathrm{G}}} \sum_{m=1}^{N_{\mathrm{M}}} MC_{\mathrm{up/dn,en,seg}}^{i,m,t} G_{\mathrm{up/dn,en,seg}}^{i,m,t} \tag{14}$$

subject to

$$\boldsymbol{h_2}(\boldsymbol{x}, \boldsymbol{u}) = \mathbf{0}, \tag{15}$$

$$\boldsymbol{g_2}(\boldsymbol{x}, \boldsymbol{u}) \leq \mathbf{0} \tag{16}$$

where N_{G} and N_{M} are the number of generators and cost segments of the generators offer, respectively. The set of decision variables comprises

$$\boldsymbol{\vartheta_2} = \left\{G_{\mathrm{up/dn,en,seg}}^{i,m,t}\right\}.$$

The most recent re-dispatch prices or the average of the most recent prices are used for the imbalance settlement at the time instant of physical delivery [31]. This pricing scheme is ex post, and assumes that the demand for balancing energy is inelastic. Variable $G_{\mathrm{up/dn,en,seg}}^{i,m,t}$ represents the injection of real-time up/dn balancing energy production. $MC_{\mathrm{up/dn,en,seg}}^{i,m,t}$ is the marginal costs of up/down balancing energy in segment m, of BSP i, at time t. Constraints $\boldsymbol{h_2}(\boldsymbol{x}, \boldsymbol{u}) = \mathbf{0}$ refers to the equality of deviations with balancing energy. Constraints $\boldsymbol{g_2}(\boldsymbol{x}, \boldsymbol{u})$ include the capacity constraints for the generators resulting from the day-ahead clearing.

2) Imbalance Settlement in a Real-Time Balancing Energy Market: In contrast to the pricing of imbalances based on energy market information, we propose a remuneration of balancing energy based on the BRP's valuation of it. The system operator matches demand and supply for balancing energy and determines the prices of real-time balancing energy for the point of physical delivery. The difference to the real-time energy market framework presented in (14)–(16) is that it,

- differs explicitly between market operation and operations to keep system security, where the latter is the duty of the TSO. The framework therefore allows the separation of these two goals as currently done in most of the European market frameworks.
- uses as a supply curve the offers from the BSPs. The balancing energy bid block of a BSP is bounded by the amount of AS capacity scheduled on a day-ahead basis.
- considers an expected demand for balancing energy by the BRPs.

We assume that an individual BRP j has a demand for up/down balancing energy at time t, $MB_{\mathrm{up/dn,en}}^{j,t}$, of the form

$$MB_{\mathrm{up/dn,en}}^{j,t} = \left(\frac{Q_{\mathrm{up/dn,en}}^{j,t}}{B_{\mathrm{up/dn}}^{j,t}}\right)^{\gamma^{j,t}} \tag{17}$$

where $\gamma^{j,t} = (1)/(\eta_{\mathrm{up/dn,en}}^{j,t})$. $Q_{\mathrm{up/dn,en}}^{j,t}$ is the real-time deviation of BRP j from the schedule at time t, $F_{\mathrm{up/dn,en}}^{j,t}$ is a positive factor, and $\eta_{\mathrm{up/dn,en}}^{j,t}$ is the price elasticity for balancing energy. Formally, (14)–(16) can be extended as

$$\min_{\boldsymbol{\vartheta_3}} \cdot \sum_{i=1}^{N_{\mathrm{G}}} \sum_{m=1}^{N_{\mathrm{M}}} MC_{\mathrm{up/dn,en,seg}}^{i,m,t} G_{\mathrm{up/dn,en,seg}}^{i,m,t} - \sum_{n=1}^{N_{\mathrm{N}}} \overline{MB}_{\mathrm{up/dn,en,seg}}^{n,t} D_{\mathrm{up/dn,en,seg}}^{n,t} \tag{18}$$

subject to

$$\boldsymbol{h_3}(\boldsymbol{x}, \boldsymbol{u}) = \mathbf{0}, \tag{19}$$

$$\boldsymbol{g_3}(\boldsymbol{x}, \boldsymbol{u}) \leq \mathbf{0} \tag{20}$$

where

$$\boldsymbol{\vartheta_3} = \left\{ G^{i,m,t}_{\mathrm{up/dn,en,seg}}, D^{n,t}_{\mathrm{up/dn,en,seg}} \right\}.$$

Parameter $\overline{MB}^{n,t}$ represents segment n of the piece-wise sum of all BRP balancing energy demand curves at time t [32], [33]. $D^{n,t}_{\mathrm{up/dn,en,seg}}$ is the market clearing demand. Constraints $\boldsymbol{h_3}(\boldsymbol{x},\boldsymbol{u}) = \mathbf{0}$ and $\boldsymbol{g_3}(\boldsymbol{x},\boldsymbol{u}) = \mathbf{0}$ represent the balance of generation and demand, and the generation limits for balancing energy, respectively. The shown benefit function gives a constant price elasticity for deployed energy. This means that the percentage change of the marginal benefit of deployed energy in response to the amount of deployed energy stays constant. Other forms such as a quadratic cost function, or linear cost function are conceivable. Note that those demand functions have different price elasticities depending upon the point of operation. We chose this function because it combines aspects of a quadratic benefit functions with a lower number of parameters of freedom, namely two. The evaluation of which cost function fits best depending upon the assumed technology for balancing and the market environment, is out of the scope of this paper. Given this framework, we have to consider 1) how the demand for balancing energy is determined, and 2) that physically only the aggregation of all deviations matter in terms of deployed balancing energy.

The cost allocation of the deployed balancing energy can be viewed as a public good problem. Public goods are commodities which are non-excludable (or only at high costs), which means that an individual can be excluded from the consumption of it, and non-rivalrous, which means that the consumption of the good does not interfere with the desires of other individuals. One problem with public goods is that individuals can benefit from them without contributing sufficiently to their production. Fig. 2(a) shows the mechanism to aggregate the individual demand curves for balancing energy. The established equilibrium in the public good case is called a Lindahl equilibrium [34]. This cost allocation methodology requires the implementation of a preference revelation mechanism such as the Groves-Clarke mechanism which enables preference revelation in case of public good provision [35].

Fig. 2(b) illustrates this mechanism: Given the individual demand curves, several market equilibria are calculated, each one leaving out always one demand curve. The Groves-Clarke tax, $\mathrm{Ar_C}$, represents the costs that a participant imposes on the other market participants by consuming the public good. Area $\mathrm{Ar_B}$ represents the benefit that the BRP obtains by consuming the public good. If the BRP misrepresents its preferences, i.e., by stating a lower marginal benefit of consuming the public good, it loses welfare.

This preference revelation mechanism requires the solution of $N_{\mathrm{BRP}} + 1$ optimization problems in order to determine the influence of every BRP on the energy clearing. Area $\mathrm{Ar_A}$ has the purpose of ensuring that there is sufficient revenue sufficiency to cover the costs of balancing energy. We assume it to be

$$Ar_A = \sum_{j=1}^{N_{\mathrm{BRP}}} p^j_{\mathrm{up/dn,en}} D^{j,t}_{\mathrm{up/dn,en,min1}} \tag{21}$$

where

$$p^j_{\mathrm{up/dn,en}} \sim \mathcal{U}(LB, UB), \forall j. \tag{22}$$

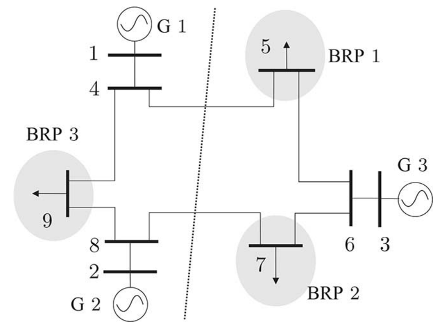


Fig. 3. Considered test system with BRPs at buses 5, 7, and 9, BSPs at buses 1, 2, and 3. In the course of the simulations, we consider transmission limits between 4–5 and 8–7.

Parameter $D^{j,t}_{\mathrm{up/dn,en,min1}}$ is the clearing quantity when the demand curve of BRP j is removed. The weighting factor $p^j_{\mathrm{up/dn,en}}$ is drawn from a uniform distribution where the lower bound, LB, and the upper bound, UB, are determined by the system operator. Due to the revenue sufficiency part, $\mathrm{Ar_A}$, this preference revelation mechanism may charge balance responsible parties more than necessary to recover the costs of balancing energy costs, which reduces the overall efficiency. The outcome is Pareto optimal, if the amount of payments collected is not greater than the total cost of the public good. Excess payments to the system operator beyond cost remuneration may require an appropriate redistribution algorithm, which weakens again incentive compatibility. The Groves-Clarke tax is only non-zero as long as the preference of the BRP has an influence on the market outcome.

III. Test System and Simulation Framework

We evaluate the proposed approach and compare it with alternative imbalance settlement frameworks proposed in the literature and implemented in practice. We also investigate the influence of locational pricing and the change in BRP wise payments in case that no incentive compatibility constraints are set.

A. Test System

We use the IEEE 9-bus test system as shown in Fig. 3. The authors chose a small system in order to be able to highlight how payment change with the preferences the BRP. However, bigger test systems are conceivable but do not change the argument of the paper. We assume three BRPs at nodes 5, 7, and 9, respectively. The BSPs are located at buses 1, 2, and 3. The BRPs have predefined preferences for AS capacity and balancing energy. Further data are given in the Appendix. The approach was implemented in MATLAB using the interface YALMIP and IBM ILOG CPLEX as the solver [36], [37].

B. Real-Time Imbalances

All approaches are evaluated given the same set of imbalances. We draw several physical imbalances of every BRP from a normal distribution function in every hour t

$$Q^{j,t}_{\mathrm{up/dn,en}} \sim \mathcal{N}(\mu, \sigma^2) \tag{23}$$

where $\mu = 0$ and $\sigma^2 = 1\%$ of the actual demand of the BRP, $D^{j,t}_{\mathrm{En,seg}}$. We proceed with a simple Monte Carlo simulation for all the approaches and assess the expected payments in case of imbalances.

TABLE I
ONE PRICE SYSTEM WITH NO ADDITIONAL PENALTY FACTORS

BRP/System	Long	Short
Long	$0.5\lambda^{n,t}_{\text{En,DA}}Q^{j,t}_{\text{up,en}}$	$0.5\lambda^{n,t}_{\text{En,DA}}Q^{j,t}_{\text{up,en}}$
Short	$-1.5\lambda^{n,t}_{\text{En,DA}}Q^{j,t}_{\text{dn,en}}$	$-1.5\lambda^{n,t}_{\text{En,DA}}Q^{j,t}_{\text{dn,en}}$

C. Benchmark Approaches

We compare our approach with stylized versions of one- and two-price systems as explained in the following. We assess the expected sum of payments for deployed energy given the imbalances drawn from (23). The parametrization of the demand function of the proposed approach in (18)–(20) is such that it very well covers the clearing quantities in (23). All benchmark mechanisms are ex-post pricing mechanisms and do not provide a real-time price signal to the BRP. Further, different from the proposed approaches, their validity in terms of being incentive compatible which means that market participants are not tempted to game the market cannot be theoretically proven [9]. One-price schemes allocate the cost of deployed balancing energy independently from the imbalance status of the system. They are in general preferable to two-price schemes, which penalize imbalances asymmetrically depending upon whether the system's net power balance is positive or negative. For example, Switzerland has implemented a one-price scheme to settle imbalances [38].

Capacity remuneration is important to encourage the long-term supply of sufficient AS capacity [6]. This form of remuneration may be done either via a uniform socialization and grid tariffs, a periodical fee, or as an additional component to the balancing energy payments. For example, the imbalance settlement schemes in Austria and Germany incorporate an additive component dependent upon the extent of real-time deviations [39], [40]. However, these forms of remuneration are not transparent since they are established on heuristic rules and may create too view or excess payments to the TSO for capacity reservation.

1) Symmetric-Settlement (Sym): Table I illustrates that the imbalance charge is computed depending on the net position of the BRP and the overall system [6]. For example, in the upper left box, the TSO pays the BRP for excess production. In the lower left box the BRP has to pay a penalty for a negative generation demand mismatch. The settlement does not include additional penalty factors. Parameter $\lambda^{n,t}_{\text{En,DA}}$ is the day-ahead clearing price at node n and time t for traded energy and $Q^{j,t}_{\text{up/dn,en}}$ is the real-time up/down imbalance, where $Q^{j,t}_{\text{up/dn,en}} \geq 0$, respectively. The approach *Sym* has the advantages of a one-price system as stated previously. However, it includes components from energy market operation and is therefore prone to gaming.

2) Asymmetric-Settlement (Asym): Table II illustrates the case of an asymmetric settlement [6]. We assume additional penalty factors depending on the contribution to the overall system balance. The approach *Asym* has the characteristics of a two-price system as stated previously. This approach also incorporates energy market components and due its weighting factors creates additional incentives to use the balancing market as a mechanism to circumvent high costs in the energy market trading.

3) Settlement Based on the Price of Balancing Energy Without/With Capacity Component (En/EnCap): The previous settlement schemes do not include 1) the price of balancing energy but use instead the day-ahead price for traded energy and 2) the remuneration of AS capacity. In the imbalance settlement scheme shown in Table III, we consider the price for up/down balancing energy and we consider AS capacity costs with an additive component. The additive component does not depend on the net position of the BRP or the control area. The additive component per BRP for a time instant t includes the commitment costs of providing reserves, the AS capacity costs for event-based AS, and the costs for non-event-based AS, which are socialized among all BRPs

$$\text{cap}^{j,t} = \frac{1}{N_L}\frac{\left(C_{\Delta\text{commit}} + C^{\text{evt}}_{\text{cap}} + C^{\text{noevt}}_{\text{cap}}\right)}{N_t}. \tag{24}$$

However, this setup still does not fulfill the economic requirements of cost allocation according to cost causality for capacity costs. Further, the setup is not incentive compatible as (4)–(13) and (18)–(20).

4) Swiss-System Settlement (Swiss): In Table IV we use a simplified version of the imbalance settlement framework of the Swiss TSO. As in the previous symmetric settlement schemes, the imbalance charge is independent of the net position of the overall system, however it still incorporates the traded energy prices and in a small market may be prone to gaming:

$$A = \min\left(\lambda^{n,t}_{\text{En,DA}}, \lambda^{n,t}_{\text{up,cap}}\right), \tag{25}$$

$$B = \min\left(\lambda^{n,t}_{\text{En,DA}}, \lambda^{n,t}_{\text{dn,cap}}\right). \tag{26}$$

Parameter $\lambda^{n,t}_{\text{up/dn,cap}}$ is the day-ahead clearing price for non-event up/down-reserve capacity at node n at time t. The parameters values $P_1 = 100$ (\$)/(MWh), $P_2 = 50$ (\$)/(MWh), $\alpha_1 = 1.1$, and $\alpha_2 = 0.9$ from [38].

TABLE II
TWO PRICE SYSTEM WITH DISTINCTION BETWEEN SUPPORTING AND COUNTERACTING BALANCE STATE OF THE BRP

BRP/System	Long	Short
Long	$\frac{\lambda^{n,t}_{\text{En,DA}}}{(1+0.25)}Q^{j,t}_{\text{up,en}}$	$\lambda^{n,t}_{\text{En,DA}}Q^{j,t}_{\text{up,en}}$
Short	$-\lambda^{n,t}_{\text{En,DA}}Q^{j,t}_{\text{dn,en}}$	$-\lambda^{n,t}_{\text{En,DA}}(1+0.4)Q^{j,t}_{\text{dn,en}}$

TABLE III
IMBALANCE SETTLEMENT WITH ADDITIONAL CAPACITY REMUNERATION

BRP/System	Long
Long	$\lambda^{t}_{\text{up/dn,En}}Q^{j,t}_{\text{up,en}}(-cap^{j,t})$
Short	-$\lambda^{t}_{\text{up/dn,En}}Q^{j,t}_{\text{dn,en}}(-cap^{j,t})$

TABLE IV
SIMPLIFIED IMBALANCE SETTLEMENT SCHEME OF SWITZERLAND. THE BRPS SETTLEMENT IS INDEPENDENT FROM THE NET POSITION OF THE TSO

BRP/System	Long/Short
Long	$(A + P_1)\alpha_1 Q^{j,t}_{\text{up,en}}$
Short	$(B - P_2)\alpha_2 Q^{j,t}_{\text{dn,en}}$

D. Cost Recovery of AS Capacity and Balancing Energy

We test our approach in terms of recovery of costs of procured AS capacity and procured balancing energy. Fig. 4 shows the ratio between the charges imposed in total on the BRPs and the costs of procured up/down AS capacity comprising event-based reserves, non-event-based reserves, and additional commitment

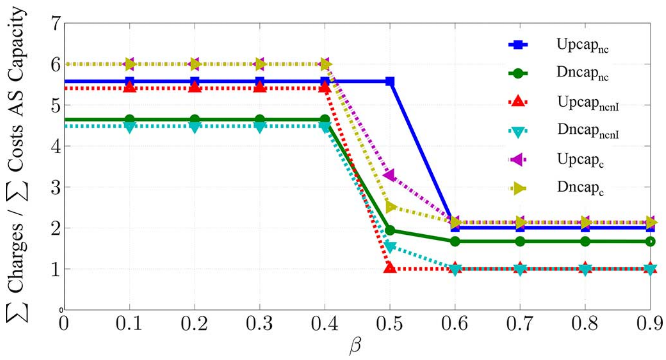


Fig. 4. Cost recovery of AS capacity dependent upon a weighting of the TSO surplus and the BRP surplus, β. Shown scenarios comprise up and down reserve capacity and no congestion in the network ($\mathrm{Upcap_{nc}}$ and $\mathrm{Dncap_{nc}}$), no congestion and no incentive compatibility constraints ($\mathrm{Upcap_{ncnI}}$ and $\mathrm{Dncap_{ncnI}}$), and congestion between lines 4–5 and 7–8 ($\mathrm{Upcap_{c}}$ and $\mathrm{Dncap_{c}}$).

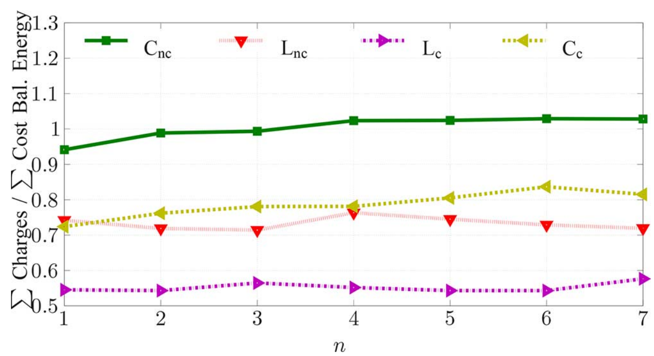
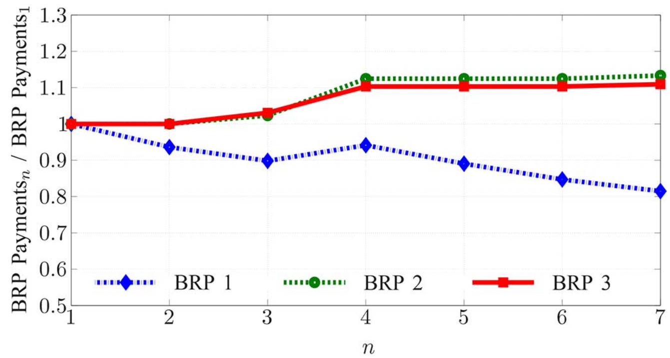
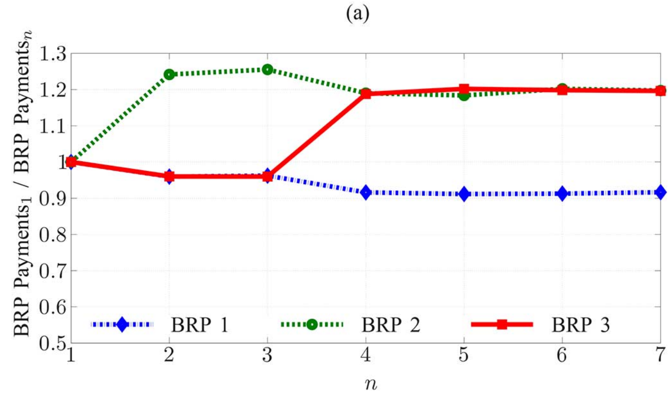


Fig. 5. Ratio of BRP payments for balancing energy to costs of procured balancing energy by the TSO in a Lindahl clearing framework, L, and in case of Groves-Clarke payments, C, dependent upon the change of BRP 1 change of elasticity of demand. Scenarios comprise no congestion (L_{nc} and C_{nc}), and congestion (L_c and C_c).



(a)



(b)

Fig. 6. Ratio of payments compared with base case ($n = 1$) of BRPs dependent upon a rising price elasticity of BRP 1 in case of (a) Lindahl clearing and (b) Clarke payment.

costs, dependent upon the weighting factor β in the maximization problem of TSO profits and BRP surplus. The shown scenarios include

- no congestion in the network ($\mathrm{Upcap_{nc}}$ and $\mathrm{Dncap_{nc}}$);
- no congestion and no incentive compatbility constraints ($\mathrm{Upcap_{ncnI}}$ and $\mathrm{Dncap_{ncnI}}$);
- congestion between lines 4–5 and 7–8 ($\mathrm{Upcap_{c}}$ and $\mathrm{Dncap_{c}}$).

We find that due to an increase of the weighting factor β over 0.5, we achieve an reasonable cost recovery mechanism for AS capacity. The existence of incentive compatibility constraints reduces the efficiency of cost recovery. An intuitive trade-off between the amount of truthful information exchange and efficiency in the market solution can be seen. In order to minimize the costs of system operation for market participants, β should be kept in our simulations fixed above 0.5. Otherwise the TSO would get excess payments. However, compared to socialization of costs via grid tariffs, the algorithm gives a transparent recovery of costs and incentives BRP which highly value AS capacity to pay more. The existence of network congestion additionally leads in all investigated approaches to efficiency losses. We find, that the extent of these losses is dependent upon the system setup.

Fig. 5 shows the total recovery of costs for balancing energy as a function of the individual elasticity of demand for balancing energy per BRP. $\mathrm{L_{nc/c}}$ and $\mathrm{C_{nc/c}}$ are the total payments in case of a Lindahl clearing, L, or a Clarke mechanism, C, in presence of no congestion (nc) or congestion (c). We assume that BRP 1 changes its elasticity of demand according to $\Delta\eta^{1,t} = -0.035 * (n-1)$ for every time instant t where n is a control variable. We find that an incentive payment via Groves Clarke leads in general to higher payments in case of imbalances. However, total payments stay constant even as BRP 1 changes its preference. Note that we did not assume a nodal-pricing scheme for balancing energy since network congestion has already been priced in the course of AS capacity reservation.

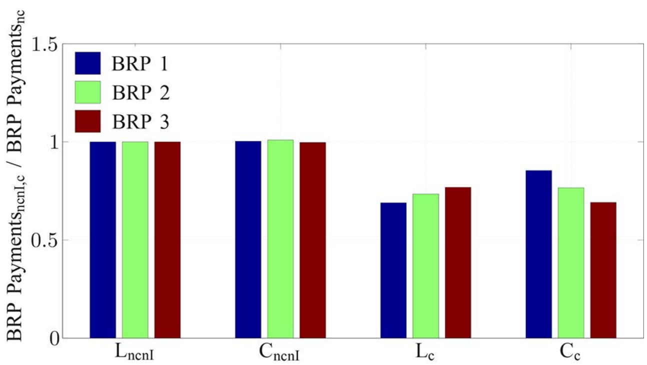
In Table V we list the ratio of imbalance payments to costs of balancing energy in the benchmark approaches in case of no congestion (nc) and congestion (c) (nodal pricing framework). The costs of approaches $\mathrm{EnCap_{nc/c}}$ also include the costs of AS capacity (event-based reserves, non-event-based reserves and additional commitment costs). We find that our approach is comparable to approaches of symmetric and asymmetric settlement. However, these approaches do not ensure payments dependent upon the individual preference of the BRP and its willingness to avoid real-time deviations. Further, the ex-post settlement of the benchmark approaches does not contain any real-time price component.

E. Influence of Change of Preferences on Energy Payments Per BRP

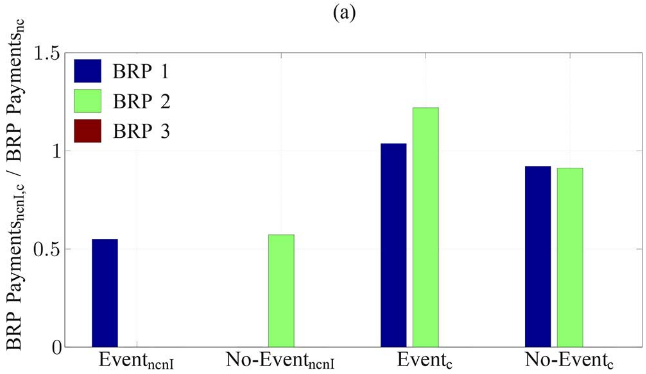
Fig. 6(a) and (b) shows the change in BRP payments as BRP 1 changes its preference for balancing energy. Since the total payments stay constant as seen in Fig. 5, the payments of the other BRP have to rise. This may lead to a general tendency that BRPs try to avoid the use of balancing energy in a non-cooperative setting.

TABLE V
SUM OF PAYMENTS OF BRPS IN % TO THE TOTAL COSTS OF BALANCING ENERGY (...* COMPRISES ALSO THE COSTS OF AS CAPACITY)

$\mathrm{Sym}_{\mathrm{nc}}$	84.48	$\mathrm{Sym}_{\mathrm{c}}$	73.07
$\mathrm{Asym}_{\mathrm{nc}}$	99.47	$\mathrm{Asym}_{\mathrm{c}}$	84.44
$\mathrm{Swiss}_{\mathrm{nc}}$	175.89	$\mathrm{Swiss}_{\mathrm{c}}$	167.75
$\mathrm{En}_{\mathrm{nc}}$	299.99	En_{c}	300
$\mathrm{EnCap}_{\mathrm{nc}}$	152.18*	$\mathrm{EnCap}_{\mathrm{c}}$	152.42*



(a)



(b)

Fig. 7. Change in BRP payments for balancing energy and AS capacity compared to benchmark dependent upon assumed simulation scenario. (a) Energy. (b) Capacity.

F. *Effects of Incentive Compatibility and Congestion on BRP Payments*

In Fig. 7(a) and (b), we show the BRP-wise change in payments for balancing energy and AS capacity in the case of no incentive compatibility constraints and congestion on the BRPs payments, compared with the base case with no congestion and incentive compatibility constraints. We find that in case of payments for balancing energy as shown in Fig. 7(a), congestion leads to a decrease in the payments as also seen in Fig. 5. With regards to changes in charges for AS capacity, Fig. 7(b) shows a decrease in the charges for event-based and non-event-based reserves in the case of no-incentive compatibility constraints and no congestion. However, congestion and a rise in the procurement costs leads to a shift of charge dependent upon the location of the BRP.

IV. CONCLUSION AND FUTURE WORK

This paper proposes a novel mechanism to allocate costs of ancillary service capacity and balancing energy based on the willingness of balance responsible parties to pay for reserve

TABLE VI
TECHNICAL DATA SYSTEM

	$\overline{G}$	$\underline{G}$	$Initial\ Status[MW]$	Start-Up [$]
G_1	150	0	1	450
G_2	120	0	1	400
G_3	80	0	1	300

TABLE VII
ECONOMIC DATA GENERATORS. THE NUMBERS IN ONE TABLE ELEMENT REFER TO ONE SEGMENT OF THE GENERATOR COSTS CURVES, RESPECTIVELY

	$MC_{En}\ \frac{[\$]}{MW}$	$MC_{up}\ \frac{[\$]}{MW}$	$MC_{dn}\ \frac{[\$]}{MW}$
G_1	39.49/40.02/40.55	42.49/43.02/45.55	39.49/40.02/40.55
G_2	53.01/54.24/55.41	56.01/58.24/59.41	53.01/54.24/55.41
G_3	63.01/64.24/65.41	65.01/67.24/68.41	63.01/64.24/65.41

TABLE VIII
ECONOMIC DATA BALANCE RESPONSIBLE PARTIES, CAPACITY DEMAND

	$a^j/b^j/c^j$	PD_{Base}	ϵ/A^t
BRP 1	2000/200/1.76	90	$-0.35/2s^tPD_{Base}$
BRP 2	1300/150/1.6	100	$-0.35/2s^tPD_{Base}$
BRP 3	800/120/1.36	125	$-0.35/2s^tPD_{Base}$

TABLE IX
ECONOMIC DATA BALANCE RESPONSIBLE PARTIES: WILLINGNESS TO PAY FOR AS CAPACITY, BASE ENERGY DEMAND, PARAMETERS FOR DEMAND FOR BALANCE ENERGY

	$a^j/b^j/c^j$	PD_{Base}	$\eta^{j,t}\ /\ B^{j,t}_{\mathrm{up/dn}}$
BRP 1	2450/140/1.8	90	$-1.0\ /\ 2s^tPD_{Base}$
BRP 2	1750/115/1.4	90	$-1.2\ /\ 2s^tPD_{Base}$
BRP 3	1050/70/0.9	115	$-1.4\ /\ 2s^tPD_{Base}$

TABLE X
TIME SERIES OF BRP DEMAND: FACTORS s^t ARE MULTIPLIED WITH BASE ENERGY DEMAND PD_{Base}

t	1	2	3	4	5	6	7	8
I	0.60	0.60	0.60	0.59	0.59	0.60	0.74	0.86
II	0.62	0.61	0.61	0.58	0.60	0.65	0.79	0.82
III	0.61	0.61	0.61	0.61	0.61	0.60	0.64	0.76
t	9	10	11	12	13	14	15	16
I	0.95	0.96	0.96	0.95	0.95	0.95	0.93	0.94
II	0.94	0.94	0.95	0.95	0.90	0.95	0.93	0.94
III	0.95	0.96	0.96	0.95	0.95	0.95	0.93	0.94
t	17	18	19	20	21	22	23	24
I	0.99	1	1	0.96	0.91	0.83	0.73	0.63
II	0.95	0.95	0.95	0.96	0.95	0.85	0.63	0.63
III	0.79	0.60	0.50	0.55	0.41	0.43	0.43	0.43

capacity and balancing energy. We have presented a recovery mechanism for ancillary service capacity costs, where excess charges may be paid due to incentive compatibility assurance. However, the proposed approach enhances market efficiency since balancing services are remunerated and provided based on the individual valuation of reserves. The market framework can be operated by two different entities such as a market operator and a system operator and is therefore also valid for power market setup in continental Europe. However, it differs from current mechanisms used in European power systems because it also provides real-time price signals. It therefore may be seen as a hybrid form of centrally organized markets with a system operator, as in US power systems, and a decentralized self-scheduling setting. It provides financial incentives for decentralized netting of imbalances and performs at least as well as various benchmark approaches tested in this paper. Finally, the proposed approach is able to deal with locational price signals, which is a crucial market design feature when it comes to scarcity conditions in transmission.

Appendix

Tables VI–X contain system data used for the simulations.

References

[1] A. Abbasy and R. Hakvoort, "Exploring the design space of balancing services markets—A theoretical framework," in *Proc. 2nd Int. Conf. Infrastructure Systems and Services: Developing 21st Century Infrastructure Networks (INFRA)*, 2009.

[2] R. van der Veen and R. Hakvoort, "Balance responsibility and imbalance settlement in northern Europe—An evaluation," in *Proc. 6th Int. Conf. European Energy Market, EEM*, 2009.

[3] S. Oren, "Design of ancillary service markets," in *Proc. 34th Hawaii Int. Conf. System Sciences*, 2001, pp. 1–9.

[4] H. Singh and A. Papalexopoulos, "Competitive procurement of ancillary services by an independent system operator," *IEEE Trans. Power Syst.*, vol. 14, no. 2, pp. 498–504, May 1999.

[5] Y. Smeers, "Study on the general design of electricity market mechanisms close to real time," Commissioned by: The Commission for Electricity and Gas Regulation (CREG), 2008.

[6] L. Vandenzande, L. Meeus, R. Belmans, M. Saguans, and J.-M. Glachant, "Well functioning balancing markets: A prerequisite for wind power integration," *Energy Policy*, vol. 38, pp. 3146–3154, 2010.

[7] C. Weber, "Adequate intraday market design to enable the integration of wind energy into the European power systems," *Energy Policy*, vol. 38, pp. 3155–3163, 2010.

[8] R. Baldick, U. Helman, B. Hobbs, and R. O'Neill, "Design of efficient generation markets," *Proc. IEEE* (Invited Paper), vol. 93, no. 11, pp. 1998–2012, Nov. 2005.

[9] A. Mas-Colell, M. Whinston, and J. Green*, Microeconomic Theory*. New York, NY, USA: Oxford Univ. Press, 1995.

[10] M. Fahrioğlu and F. Alvarado, "Using utility information to calibrate customer demand management behavior models," *IEEE Trans. Power Syst.*, vol. 16, no. 2, pp. 317–322, May 2001.

[11] F. Ramsey, "A contribution to the theory of taxation," *Econ. J.*, vol. 37, pp. 47–61, 1927.

[12] C. Schlereth, T. Stepanchuk, and B. Skiera, "Optimization and analysis of the profitability of tariff structures with two-part tariffs," *Eur. J. Oper. Res.*, vol. 206, pp. 691–701, 2010.

[13] W. Hogan, "Revenue efficiency and cost allocation," Comments Submitted to the Federal Energy Regulatory Commission, 2006 [Online]. Available: http://ksghome.harvard.edu/

[14] J. Rawls*, A Theory of Justice*. Cambridge, MA, USA: Belknap Press of Harvard Univ. Press, 1971.

[15] P. Diamond, "A many-person Ramsey-rule," *J. Public Econ.*, vol. 4, no. 4, pp. 335–342, 1975.

[16] G. Angelidis and A. Papalexopoulos, "On the operation and pricing of real-time competitive electricity markets," in *Proc. IEEE Power Eng. Soc. Winter Meeting*, 2002, pp. 420–427.

[17] S. Siddiqi and M. Baughman, "Reliability differentiated real-time pricing of electricity," *IEEE Trans. Power Syst.*, vol. 8, no. 2, pp. 548–554, May 1993.

[18] S. Oren, "The reliability at a price concept," in *Proc. IEEE Power Eng. Soc. Summer Meeting*, 2002, pp. 631–633.

[19] T. Haring and G. Andersson, "Ensuring energy market liquidity through adequate imbalance settlement," in *Proc. 51th University Power Conf., UPEC*, 2012.

[20] A. Abbasy, R. van der Veen, and R. Hakvoort, "Possible effects of balancing market integration on performance of the individual markets," in *Proc. 8th Int. Conf. European Energy Market, EEM*, 2011.

[21] A. Zobian and M. Ilic, "Unbundling of transmission and ancillary services part I: Technical issues," *IEEE Trans. Power Syst.*, vol. 12, no. 2, pp. 539–548, May 1997.

[22] A. Zobian and M. Ilic, "Unbundling of transmission and ancillary services—Part II: Cost-based pricing framework," *IEEE Trans. Power Syst.*, vol. 12, no. 2, pp. 549–558, May 1997.

[23] Y. Rebours, D. Kirschen, M. Trotignon, and S. Rossignol, "Survey of frequency and voltage control ancillary services—Part I: Technical features," *IEEE Trans. Power Syst.*, vol. 22, no. 1, pp. 350–357, Feb. 2007.

[24] Y. Rebours, D. Kirschen, M. Trotignon, and S. Rossignol, "Survey of frequency and voltage control ancillary services—Part II: Economic features," *IEEE Trans. Power Syst.*, vol. 22, no. 1, pp. 358–366, Feb. 2007.

[25] Y. T. Tan and D. Kirschen, "Co-optimization of energy and reserve in electricity markets with demand-side participation in reserve services," in *Proc. Power Systems Conf. Expo. (PSCE)*, 2006, pp. 1182–1189.

[26] K. Margellos, T. Haring, P. Hokayem, M. Schubiger, J. Lygeros, and G. Andersson, "A robust reserve scheduling technique for power systems with high wind penetration," in *Proc. Probabilistic Methods Applied to Power Systems, PMAPS*, 2012.

[27] T. Haring and G. Andersson, "Cost allocation in ancillary service markets," in *Proc. Hawaii Int. Conf. System Sciences (HICSS)*, 2014.

[28] T. Haring, D. Kirschen, and G. Andersson, "Efficient allocation of balancing and ramping costs," in *Proc. 18th Power Systems Computation Conf. (PSCC)*, Wroclaw, Poland, Aug. 18–22, 2014.

[29] T. Qiu, T. Haring, and D. Kirschen, "Cost recovery in a rolling horizon unit commitment with energy storage," in *Proc. Power Systems Computation Conf. (PSCC)*, Wroclaw, Poland, Aug. 18–22, 2014.

[30] L. Garces, A. Conejo, R. Garcia-Bertrand, and R. Romero, "A bilevel approach to transmission expansion planning within a market environment," *IEEE Trans. Power Syst.*, vol. 24, no. 3, pp. 1513–1522, Aug. 2009.

[31] CAISO, last visited Aug. 2, 2014 [Online]. Available: http://www.caiso.com/Documents/DiscussionPaper-Real-timeRevenueImbalance_CaliforniaISO_Markets.pdf

[32] A. Magnani and S. P. Boyd, "Convex piecewise-linear fitting," *Optimiz. Eng.*, vol. 10, pp. 1–17, 2009.

[33] S. Boyd and L. Vandenberghe*, Convex Optimization*. Cambridge, U.K.: Cambridge Univ. Press, 2004.

[34] E. Lindahl, "Just taxation—A positive solution," in *Musgrave, R. A.; Peacock, A. T., Classics in the Theory of Public Finance*. London, U.K.: Macmillan, 1919.

[35] E. Clarke, "Multipart pricing of public goods," *Public Choice*, vol. 11, no. 1, pp. 17–33, 1971.

[36] J. Löfberg, "Yalmip: A toolbox for modeling and optimization in MATLAB," in *Proc. CACSD Conference*, Taipei, Taiwan, 2004 [Online]. Available: http://users.isy.liu.se/johanl/yalmip

[37] IBM ILOG CPLEX [Online]. Available: http://www.ilog.com

[38] Swissgrid, "General balance group regulations," last visited Aug. 2, 2014 [Online]. Available: http://www.swissgrid.ch/dam/swissgrid/experts/legal_system/balance_group/en/130410_AllgemeineBilanzgruppenRegelungen_V1-5_EN.pdf

[39] APCS, last visited Aug. 2, 2014 [Online]. Available: http://www.apcs.at/en/rules/market-rules/current-version

[40] TenneT, last visited Aug. 2, 2014 [Online]. Available: http://www.tennettso.de/site/en/Transparency/publications/balance-group/price-position

Tobias W. Haring (S'10) received the Master's degrees in electrical engineering and economics at Technical University of Graz and the University of Graz, Austria. He is pursuing the Ph.D. degree at the Power System Laboratory at ETH Zurich, Switzerland.

His research interests are optimization, power system analysis, and electricity market design.

Daniel S. Kirschen (M'86–SM'92–F'07) received the electrical and mechanical engineer's degrees from the Université Libre de Bruxelles, Belgium, in 1979, and the M.Sc. and Ph.D. degrees from the University of Wisconsin, Madison, WI, USA, in 1980 and 1985, respectively.

He is currently Close Professor of Electrical Engineering at the University of Washington, Seattle, WA, USA. His research focuses on smart grids, the integration of renewable energy sources in the grid, power system economics, and power system security.

Göran Andersson (M'86–SM'91–F'97) received the M.Sc. and Ph.D. degrees from the University of Lund, Sweden, in 1975 and 1980, respectively.

Since 2000, he has been a Full Professor in electric power systems at ETH Zürich (Swiss Federal Institute of Technology), where he also heads the Powers System Laboratory. His research interests include power systems dynamics and control, power markets, and future energy systems.