Well-functioning balancing markets as a prerequisite for wind power integration

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ABSTRACT

This article focuses on the design of balancing markets in Europe taking into account an increasing wind power penetration. In several European countries, wind generation is so far not burdened with full balancing responsibility. However, the more wind power penetration, the less bearable for the system not to allocate balancing costs to the responsible parties. Given the intermittency and limited predictability of wind generation, full balancing exposure is however only feasible conditionally to well-functioning balancing markets. On that account, recommendations ensuring an optimal balancing market design are formulated and their impact on wind generation is assessed. Taking market-based or cost-reflective imbalance prices as the main objective, it is advised that: (1) the imbalance settlement should not contain penalties or power exchange prices, (2) capacity payments should be allocated to imbalanced BRPs via an additive component in the real-time price and (3) a cap should be imposed on the amount of reserves.

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KEYWORDS

Electricity market design, balancing services, wind power integration

1. Introduction

Many policy analyses on wind power integration mainly compare RES-E support policies such as feed-in tariffs and quota systems. However, the success of wind energy deployment does not only depend on the efficiency of support policies but also on the design of electricity markets and the interaction between both (Ragwitz et al., 2007).

In several European countries, wind generation is so far not fully exposed to market risks including balancing responsibility. While such an approach can be justified in countries with a low share of wind in the total generation mix, countries with a higher wind share and a significant impact of wind on their system should burden more responsibility and risks on wind generation in order to give them an incentive for cost-reflective market behaviour and as such limit the indirect costs to society. As illustrated in Klessman et al. (2008), full market risk exposure is however only feasible conditionally to well-functioning intra-day and balancing markets.

This paper therefore focuses on the design of balancing markets in Europe. Section 2 formulates recommendations ensuring an optimal market design. Section 3 assesses the impact of these recommendations on wind generation.

2. Recommendations on balancing market design in Europe

Balancing or real-time markets provide market parties with a last resort of energy transactions. The expected prices to be brought forth by this market are reflected in wholesale prices and consequently affect market parties' decisions at the forward stage. On that account, electricity markets can only function efficiently conditionally to market-based or cost-reflective real-time prices.

Taking market-based real-time prices as the point of departure, the recommendations in Table 1 on real-time market design harmonisation are derived and elaborated on in this Section.

Table 1: Long run recommendations on real-time market design harmonisation

Real-time prices should be market-based.	
Market-based means that:	Market-based implies that:
Imbalances in real-time are settled at a price that *fully* reflects the costs of real-time balancing. → Even though there is a rationale to socialize part of reserves' costs, total procurement costs of reserves that deliver a significant amount of energy in the real-time should be fully reflected in the imbalance settlement. → An imbalance settlement based on other components such as power exchange prices and penalties is not market-based, but an additive component is necessary to settle capacity payments of reserves procurement.	A cap should be imposed on the amount of reserves such that: ▪ Their share in the energy delivered in real-time is marginal. ▪ The real-time price is mainly based on balancing services procured. As market-based solutions are not always feasible on a national scale, cross-border balancing implementation should precede market design harmonisation.

2.1. Meaning of market-based

Real-time prices are market-based insofar as they fully reflect all procurement expenses incurred by the TSO for real-time balancing. As such, real-time prices should in principle correctly pass on both energy and capacity payments

2.2.1 Allocation of energy payments

Real-time or imbalance prices are usually based on the up- and downward regulating power offers accepted by the TSO for real-time balancing. Either they start from the price of the *marginally* accepted up- or downward regulating offer or from the *average* price of all accepted up- or downward regulating offers, depending on how balancing service providers (BSP) are remunerated. For a discussion on the pros and cons of remunerating BSPs by means of marginal pricing versus average or pay-as-bid pricing, see for instance (Littlechild, 2007). Briefly, there is a widely held view that marginal pricing is economically more correct and will lead to a more efficient allocation of resources than average pricing. Apart from the choice between marginal and average pricing, a difference also exists between single and double imbalance pricing schemes. A typical one and two price system is schematically represented in Table 2 and Table 3 respectively.

Under a single imbalance pricing scheme or so-called one price system, real-time prices correspond to the marginal procurement price of balancing services, being either upward or downward regulating services depending on the overall status of the system. The same imbalance price – be it with a different sign – is applied for remaining short and long positions, making the imbalance settlement a zero sum game for the TSO.

Table 2: Imbalance settlement through a typical one price system

	SYSTEM IMBALANCE	
	NEGATIVE (short)	**POSITIVE (long)**
	▪ ∑injections < ∑off-takes	▪ ∑injections > ∑off-takes
	▪ TSO asks more production	▪ TSO asks less production
	▪ NRV > 0	▪ NRV < 0

BRP IMBALANCE	**NEGATIVE (short)** Injections < off-takes	+ MP_u	+ MP_d
	POSITIVE (long) Injections > off-takes	- MP_u	- MP_d

MP_u = marginal price of upward regulation; MP_d = marginal price of downward regulation; NRV = net regulation volume

Under a double imbalance pricing scheme or so-called two price system on the contrary, a different imbalance price is applied for positive and negative BRP imbalances. While imbalances of BRPs contributing to the system imbalance are settled at prices based on the – usually average – procurement costs of balancing services, imbalances of BRPs counteracting the system imbalance are settled on the basis of wholesale price indices, typically power exchange prices. Compared to a one price system, which settles BRP imbalances opposing the system imbalance departing from marginal costs – i.e. the additional cost the TSO would have incurred if the BRP concerned was not imbalanced –, a two price system is considered not cost-reflective. In addition, a two price system does no longer imply a zero sum game for the TSO, who should have a financial disinterest in the imbalance settlement. Accordingly, insofar the difference is not used by the TSO to cover other costs in the real-time, it should result in a reduction of transmission tariffs. But even if this is done, it still entails a transfer of money from inflexible users – such as wind generators – to average users. Furthermore, a two price system puts small market parties – again often including wind generators – at a disadvantage as it involves lower imbalance costs for larger market parties due to netting. For that reason, small market parties are “gently forced” to outsource their balance responsibility. Under a one price system on the contrary, no extra discrimination is induced according to the size of market participants.

Table 3: Imbalance settlement through a typical two price system

		SYSTEM IMBALANCE	
		NEGATIVE (short) ▪ ∑injections < ∑off-takes ▪ TSO asks more production ▪ NRV > 0	**POSITIVE (long)** ▪ ∑injections > ∑off-takes ▪ TSO asks less production ▪ NRV < 0
BRP IMBALANCE	**NEGATIVE (short)** Injections < off-takes	$+ AP_u*(1+ penalty_u)$	$+ P_{DA}$
	POSITIVE (long) Injections > off-takes	$- P_{DA}$	$- AP_d/(1+ penalty_d)$

AP_u = average price of upward regulation; AP_d = average price of downward regulation; NRV = net regulation volume; P_{DA} = day-ahead power exchange price

Finally, a two price system often includes a multiplicative component or so-called penalty that affects BRPs with regard to their position before real-time. Typically this penalty is affecting negative imbalances more strongly than positive ones, inciting BRPs as such to avoid short positions. Other than for BRP incitation – and related to this security safeguarding – penalties are imposed for practical reasons such as accounting – for instance to generate extra revenues for the recovery of intra-settlement period imbalances – and the recovery of capacity payments (cf. infra). Insofar they are not cost-reflective, penalties can give rise to undesirable BRP behaviour, including over-contracting in the wholesale market, withholding services for its own use and nominating less than the expected injections. These negative side-effects are more extensively discussed below by means of some basic examples. Note that these examples are kept simple for clarification purposes and do not aim to be exhaustive. More specifically, the following assumptions are made:

- Both the one and two price system are based on marginal procurement prices (MP).
- Marginal procurement prices are expressed as a percentage of the day-ahead price: $MP_u = 1.5*P_{DA}$ and $MP_d = 0.5*P_{DA}$: while marginal prices for upward regulation are higher than day-ahead prices, marginal prices for downward regulation are lower. For the moment, marginal procurement prices for upward regulation are usually higher than day-ahead prices. However, the better markets continue to function – and the more arbitrage opportunities are exploited –, the more day-ahead and real-time prices will converge. Note however that – even if both prices are equal – BRPs would not be indifferent between buying energy on the wholesale or real-time market. They would rather buy wholesale to hedge against typically higher and more volatile real-time prices. This is the case because not all generation resources can be controlled fast enough to deliver energy in the real-time.
- For simplification, the day-ahead price equals 1 ($P_{DA} = 1$).
- Penalties under the two price system are higher for short positions than for long ones: $Penalty_u = 0.4$ and $Penalty_d = 0.25$.
- BRPs are ignorant about the system imbalance: 50% of time positive/negative.

In Table 4 and Table 5, the above assumptions are applied to the one and two price system respectively.

Table 4: Input data for examples – One price system

		SYSTEM IMBALANCE	
		NEGATIVE (short)	**POSITIVE (long)**
BRP IMBALANCE	**NEGATIVE (short)**	+ 1.5*P_{DA} = **1.5**	+ 0.5*P_{DA} = **0.5**
	POSITIVE (long)	- 1.5*P_{DA} = **-1.5**	- 0.5* P_{DA} = **-0.5**

Table 5: Input data for examples – Two price system

		SYSTEM IMBALANCE	
		NEGATIVE (short)	**POSITIVE (long)**
BRP IMBALANCE	**NEGATIVE (short)**	+ 1.5*P_{DA}*(1+ 0.4) = **2.1**	+ P_{DA} = **1**
	POSITIVE (long)	- P_{DA} = **-1**	- 0.5* P_{DA} /(1+ 0.25) = - **0.4**

Impact of imbalance pricing on wholesale trade

To illustrate the potential impact of a two price system on wholesale markets, assume a BRP – consisting of only load – with an expected load of 100 MW or, more specifically, a load equalling 90 MW or 110 MW, each during 50% of the time. As calculated in Table 6, under a one price system, the BRP is neutral between buying energy in the wholesale or real-time market.

For instance, in case the BRP procures 90 MW on the day-ahead market – being below the expected load – he pays only 90 beforehand. In the real-time, he is balanced during half of the time. During the rest of the time, he faces a negative imbalance of -20. Therefore he pays an imbalance charge to the TSO which is calculated on the basis of an imbalance price equalling 1.5 or 0.5, depending on the direction of the system imbalance. Its expected total costs are 100. In case the BRP procures 100 MW on the day-ahead market – equalling the expected load – he pays 100 beforehand. In the real-time, he is faced with negative and positive imbalances of -10 and +10, each during 50% of the time. He accordingly pays and receives similar imbalance charges. Its expected total costs are again 100. In case the BRP procures 110 MW on the day-ahead market – exceeding the expected load – he pays 110 beforehand. In the real-time, he is balanced during half of the time. During the rest of the time, he faces a positive imbalance of 20. Therefore he receives an imbalance charge from the TSO which is calculated on the basis of an imbalance price equalling 1.5 or 0.5, depending on the direction of the system imbalance. Its expected final outcome is the same as in the former cases.

Table 6: Example on the impact of imbalance pricing on wholesale trade

	TOTAL EXPECTED COSTS	
	ONE PRICE SYSTEM	TWO PRICE SYSTEM
Purchase DA = 90	**100**	**105.5**
	= 90 + 0.5*20*(1.5+0.5)/2	= 90 + 0.5*20*(2.1+1)/2
Purchase DA = 100	**100**	**104.25**
	= 100 + 0.5*10*(1.5+0.5)/2 - 0.5*10*(1.5+0.5)/2	= 100 + 0.5*10*(2.1+1)/2 - 0.5*10*(1+0.4)/2

Purchase DA = 110	**100**	**-103**
	= 110 - 0.5*20*(1.5+0.5)/2	= 110 - 0.5*20*(1+0.4)/2

Under a two price system on the contrary, the BRP is inclined to over-contract energy on the wholesale market and in that way avoid a short position. For instance, in case the BRP procures 90 MW on the day-ahead market – being below the expected load – he pays only 90 beforehand. In the real-time, he is balanced during half of the time. During the rest of the time, he faces a negative imbalance of -20. Therefore he pays an imbalance charge to the TSO which is calculated on the basis of an imbalance price equalling 2.1 or 1, depending on the direction of the system imbalance. Its expected total costs are 105.5. In case the BRP procures 100 MW on the day-ahead market – equalling the expected load – he pays 100 beforehand. In the real-time, he is faced with negative and positive imbalances of -10 and +10, each during 50% of the time. He accordingly pays a higher imbalance charge to the TSO than he receives due to the relatively higher penalty imposed on short positions. Its expected total costs are 104.25. In case the BRP procures 110 MW on the day-ahead market – exceeding the expected load – he pays 110 beforehand. In the real-time, he is balanced during half of the time. During the rest of the time, he faces a positive imbalance of 20. Therefore he receives an imbalance charge from the TSO which is calculated on the basis of an imbalance price equalling 1 or 0.4, depending on the direction of the system imbalance. Its expected final outcome is -103.

A comparison of the expected costs under a two price system indicates that the BRP will prefer to increase its day-ahead purchases as a hedge against real-time short positions and the associated higher penalties. This BRP behaviour has an uplifting effect on wholesale prices, as modelled in Saguan (2007) and Saguan and Glachant (2007). Given that BRPs already exhibit a natural tendency to strive for long rather than balanced positions – because regulating downward is easier than regulating upward and/or downward regulating services are cheaper than upward regulating ones –, this behaviour should not be reinforced through the introduction of penalties.

Impact of imbalance settlement on the provision of balancing services

To illustrate the potential impact of a two price system on balancing services supply, assume a BRP – consisting of both generation and load – with generation equalling 110 MW and an expected load of 100 MW or, more specifically, a load equalling 90 MW or 110 MW, each during 50% of the time. As calculated in Table 7, under a one price system, the BRP is neutral between providing balancing services to the TSO via the real-time market or keeping services for own use. Note that in this example the activation cost of balancing services is taken into account. This activation cost is assumed to be equal to the marginal procurement price of upward regulating services, being 1.5.

For instance, in case the BRP offers 10 MW to the TSO, its services have a 50% chance to be activated in real-time – given a negative system imbalance during half of the time. Therefore, he receives a remuneration based on the marginal price for upward regulation, being 1.5, which exactly compensates its activation cost. Furthermore, the BRP is exposed to negative and positive imbalances of -10 and +10, each during 50% of the time. He accordingly pays and receives similar imbalance charges. Its expected final income is 0. In case the BRP keeps its 10 MW for own use, he has the possibility to avoid short positions in real-time. However, he will only activate its services on condition that the imbalance charge for short positions exceeds the activation cost. Given the imbalance prices of 1.5 and 0.5 – depending on the system imbalance – and the activation cost of 1.5, the BRP will never activate its 10 MW and will prefer to be short instead. As a result, the BRP is exposed to negative and positive imbalances of -10 and +10, each during 50% of the time. He accordingly pays and receives similar imbalance charges. Its expected final income is again 0.

Table 7: Example on the impact of imbalance pricing on the provision of balancing services

	TOTAL EXPECTED INCOME	
	ONE PRICE SYSTEM	TWO PRICE SYSTEM
Sell 10 to TSO	**0**	**-4.25**
	= 0.5*10*(1.5-1.5) - 0.5*10*(1.5+0.5)/2 + 0.5*10*(-1.5+(-0.5))/2	= 0.5*10*(1.5-1.5) - 0.5*10*(2.1+1)/2 + 0.5*10*(1+0.4)/2
Keep 10 for own use	**0**	**-2.75**
	= -0.5*10*(1.5+0.5)/2 + 0.5*10*(1.5+0.5)/2	= -0.5*10*(1.5+1)/2 + 0.5*10*(1+0.4)/2

Under a two price system on the contrary, the BRP is inclined to keep its on average excess generation for own use and in that way avoid a short position in the case load is higher than expected and the imbalance charge for short positions exceeds the activation cost. For instance, in case the BRP offers 10 MW to the TSO, its services have a 50% chance to be activated in real-time – given a negative system imbalance during half of the time. Therefore, he receives a remuneration based on the marginal price for upward regulation, being 1.5, which exactly compensates for its activation cost. Furthermore, the BRP is exposed to negative and positive imbalances of -10 and +10, each during 50% of the time. He accordingly pays a higher imbalance charge to the TSO than he receives due to the relatively higher penalty imposed on short positions. Its expected final income amounts to -4.25. In case the BRP keeps its 10 MW for own use, he has the possibility to avoid short positions in real-time. However, he will only activate its services on condition that the imbalance charge for short positions exceeds the activation cost. Given the imbalance prices of 2.1 and 1 – depending on the system imbalance – and the activation cost of 1.5, the BRP will only activate its 10 MW in case the former imbalance price holds. As a result, the BRP is exposed to negative and positive imbalances of -10 and +10, during 25% and 50% of the time respectively. He accordingly pays and receives imbalance charges. Through activation of its services during 25% of the time, he partly avoids to pay the relatively higher imbalance charge for short positions. Its expected final income is -2.75.

A comparison of both outcomes indicates that the BRP will prefer to keep its excess generation for own use as a hedge against real-time short positions and the associated penalties. This BRP "self-regulating" behaviour has a negative effect on the supply of energy in the real-time market and consequently limits TSOs' possibilities to balance the system. This effect has been mentioned in Newbery and McDaniel (2002) and Cornwall (2001). Most extremely, this behaviour could result in each BRP holding a back-up for its own largest plant, which is of course highly inefficient.

Impact of imbalance settlement on nominations

Note that this example is similar to the first one.

To illustrate the potential impact of a two price system on the accuracy of nominations, assume a BRP – consisting of only generation - with an expected generation of 100 MW or, more specifically, a generation equalling 90 MW or 110 MW, each during 50% of the time. As calculated in Table 8, under a one price system, the BRP is neutral between nominating accordingly to or differently from his expected generation.

For instance, in case the BRP sells 90 MW on the day-ahead market – being below its expected generation – he receives only 90 beforehand. In the real-time, he is balanced during half of the time. During the rest of the time, he faces a positive imbalance of +20. Therefore he receives an imbalance charge from the TSO which is calculated on the basis of an imbalance price equalling 1.5 or 0.5, depending on the direction of the system imbalance. Its expected total income is 100. In case the BRP sells 100 MW on the day-ahead market – equalling the expected generation – he receives 100 beforehand. In the real-time, he is faced with negative and positive imbalances of -10 and +10, each during 50% of the time. He accordingly pays and receives similar imbalance charges. Its expected total profit is again 100. In case the BRP sells 110 MW on the day-ahead market – exceeding the expected generation – he receives 110 beforehand. In the real-time, he is balanced during half of the time. During the rest of the time, he faces a negative imbalance of -20. Therefore he pays an imbalance charge to the TSO which is calculated on the basis of an imbalance price equalling 1.5 or 0.5, depending on the direction of the system imbalance. Its expected final outcome is the same as in the former cases.

Table 8: Example on the impact of imbalance pricing on nominations

	TOTAL EXPECTED INCOME	
	ONE PRICE SYSTEM	**TWO PRICE SYSTEM**
Sell DA = 90	**+100**	**+97**
	= 90 + 0.5*20*(1.5+0.5)/2	= 90 + 0.5*20*(1+O.4)/2
Sell DA = 100	**+100**	**+95.75**
	= 100 - 0.5*10*(1.5+0.5)/2 + 0.5*10*(1.5+0.5)/2	= 100 - 0.5*10*(2.1+1)/2 + 0.5*10*(1+0.4)/2
Sell DA = 110	**+100**	**+94**
	= 110 - 0.5*20*(1.5+(0.5))/2	=110 - 0.5*20*(2.1+1)/2

Under a two price system on the contrary, the BRP is inclined to nominate less than his expected generation and in that way avoid a short position. For instance, in case the BRP sells 90 MW on the day-ahead market – being below the expected generation – he receives only 90 beforehand. In real-time, he is balanced during half of the time. During the rest of the time, he faces a positive imbalance of +20. Therefore, he receives an imbalance charge from the TSO calculated on the basis of an imbalance price equalling 1 or 0.4, depending on the direction of the system imbalance. Its expected total income is 97. In case the BRP procures 100 MW on the day-ahead market – equalling the expected generation – he receives 100 beforehand. In the real-time, he is faced with negative and positive imbalances of -10 and +10, each during 50% of the time. He accordingly pays a higher imbalance charge to the TSO than he receives due to the relatively higher penalty imposed on short positions. Its expected total profit is 95.75. In case the BRP sells 110 MW on the day-ahead market – exceeding the expected generation – he receives 110 beforehand. In real-time, he is balanced during half of the time. During the remainder of the time, he faces a negative imbalance of 20. Therefore, he pays an imbalance charge to the TSO calculated on the basis of an imbalance price equalling 2.1 or 1, depending on the direction of the system imbalance. Its expected final outcome is 94.

A comparison of the expected profits under a two price system indicates that the BRP will prefer to under-nominate its expected injections as a hedge against real-time short positions and the associated penalties. This BRP behaviour has a negative effect on the reliability of the information TSOs receive through the nomination process.

A separate imbalance settlement to counteract the negative side-effects of a two price system

The above paragraphs illustrated the potential negative side-effects of a two price system, assuming a one step imbalance volume calculation or, in other words, a single settlement for generation and load. However, some European countries settle generation and load separately. Depending on the implementation, such a separate imbalance settlement can partly counteract the negative side-effects of a two price system.

For instance, the projected implementation of a harmonised imbalance settlement – which settles generation on the basis of a two price system and load using a one price system – in the Nordic region begin 2009, might affect the above described side-effects as follows (Nordel, 2007):

- TSO gains under a two price system – which should be redistributed via a reduction of the transmission tariffs – result in a transfer from average to inflexible users rather than the other way around.

- Small market parties – owning only load – will not be discriminated compared to larger ones as generation and load are settled separately.
- BRPs with only load will not be inclined to over-contract in the wholesale market as they are settled on the basis of a one price system.
- BRPs with both generation and load will not be incentivised to keep services for own use as generation and load are settled separately.
- BRPs with only generation will still have a tendency to nominate less than their expected injections as they are settled on the basis of a two price system.

2.2.2 Allocation of capacity payments

Necessity of capacity payments

Remunerations for capacity should be preferably avoided, amongst others because of the difficulties to accurately allocate the associated costs (cf. infra). However, two fundamental arguments account for the use of capacity payments and explain why this type of remuneration is difficult to avoid in some countries.

First, real-time markets often exhibit more volatile prices and activated volumes – and consequently more volatile revenues – than wholesale markets, inciting generators to sell on the wholesale rather than the real-time market. In such case, capacity payments – yielding a guaranteed income – can serve as a risk premium to attract more BSPs. Second, real-time markets – and in general all electricity markets – exhibit non-convexities, such as start-up costs and minimum output levels. To ensure an efficient dispatch in the presence of non-convexities and simultaneously safeguard uniform or marginal real-time energy procurement prices, these non-convexities can only be compensated for by an additional capacity payment in advance. The existence of non-convexities in electricity markets has been simply explained and illustrated in Elmaghraby et al. (2004). Note that – although being currently considered in several countries – capacity payments should not cover opportunity costs. In the presence of a well-functioning and unrestricted real-time market, BSPs have the possibility to pass on their opportunity costs via the real-time price. However, several countries still exhibit capped real-time prices, making generators' request for capacity payments covering both fixed and opportunity costs understandable.

Market-based allocation of capacity payments

Contrary to energy payments, capacity is procured for a time period far exceeding the settlement period. Consequently, its associated costs cannot be directly attributed to imbalanced BRPs. Therefore, a choice should be made between one of the following cost allocation methods.

- *Socialisation among grid users through transmission tariffs*

A socialisation of capacity payments among grid users does not entail cost-reflective real-time prices: it results in too low real-time prices as they do not include *all* procurement costs. Consequently, BRPs get fewer incentives to balance their portfolio using wholesale markets and increasingly rely on the real-time market.

A socialisation of capacity payments is justified for security insurance services, which are mainly deployed for capacity purposes and should accordingly only be remunerated for capacity. As these services mostly operate as a kind of public security insurance, their costs should not be allocated to individual BRPs. To avoid over-contracting by TSOs and consequently protect grid users against too high transmission tariffs, the amount of capacity payments for security insurance services should be regulated.

Current practices of capacity cost socialisation among grid users are manifold. Typically countries reasonably pass through the costs of primary reserves on grid users. Many countries do however allocate the costs of other services – deployed for real-time energy delivery rather than capacity purposes – via the transmission tariffs as well.

- *Socialisation among BRPs through periodical fee*

Although a socialisation of capacity payments among BRPs is already an improvement on the previous method, it does not yet provide BRPs with correct incentives. Since the periodical fee is fixed (€/period) or proportional to BRPs' injections or off-takes (€/MWh of injections/off-takes) – i.e. BRPs' size – rather than proportional to BRP's imbalances, real-time prices will again be too low, incentivising BRPs to over-rely on the real-time energy market.

Note that countries having implemented a pure one price system can only pass through energy costs via the real-time price and do have no other choice than allocating capacity costs via a socialisation among grid users or BRPs. Consequently, pure one price systems – like two price systems with non-market based components (cf. supra) – are not market-based.

Current practices of a socialisation among BRPs include:

- In France, a monthly fee – the so-called "prix proportionnel au soutirage physique" – is imposed on BRPs proportional to their off-takes to recover capacity payments of the “réserves rapides” (reserves with an activation time of 15’).

- In Great-Britain, capacity payments are partly allocated to BRPs via the so-called “BSUoS charges”, a fee imposed per settlement period (1/2 H) proportional to BRPs’ injections or off-takes.
- In the Nordic countries, a harmonised imbalance settlement will be implemented 2009 that partly allocates capacity costs through a monthly fixed fee and a fee proportional to BRPs’ measured generation or consumption.

- *Allocation to imbalanced BRPs through additive component in real-time price*

The 3rd and most market-based method consists in an inclusion of capacity costs in the real-time price (€/MWh of imbalances). Such an allocation of capacity payments is similar to the allocation of fixed costs under so-called Ramsey-Boiteux pricing, whereby fixed costs are recouped from customers by charging them prices in excess of marginal costs and this in inverse proportion to their demand elasticities. The argument of Ramsey-Boiteux pricing has been used similarly by Hogan (2006) with respect to the allocation of so-called “Resource Sufficiency Costs” in Midwest USA (MISO). Based hereupon, capacity payments can be recovered by means of an additive component[i] (component_{cap}) on top of the marginal procurement price of upward or downward regulating services ($MP_{u/d}$ (cf. supra)). Inelastic customers in this case include all BRPs that “chose” to be imbalanced despite a real-time price higher than the marginal cost of upward or downward regulation. Wind generators usually belong to the latter category. The allocation of both energy and capacity payments through the real-time price is summarised in Table 9.

Table 9: Allocation of capacity payments via the real-time price

		SYSTEM IMBALANCE	
		NEGATIVE (short) ▪ ∑injections < ∑off-takes ▪ TSO asks more production ▪ NRV > 0	**POSITIVE (long)** ▪ ∑injections > ∑off-takes ▪ TSO asks less production ▪ NRV < 0
BRP IMBALANCE	**NEGATIVE (short)** Injections < off-takes	$+ MP_u + \text{component}_{cap}$	$+ MP_d + \text{component}_{cap}$
	POSITIVE (long) Injections > off-takes	$- (MP_u - \text{component}_{cap})$	$- (MP_d - \text{component}_{cap})$

MP_u = marginal price of upward regulation; MP_d = marginal price of downward regulation; NRV = net regulated volume; component_{cap} = additive component

Note that the resulting imbalance pricing system exhibits characteristics of a one as well as two price system. Similar to a one price system, it allocates energy costs using marginal procurement prices only. Similar to a two price system, it entails different real-time prices depending on the sign of the BRP's imbalance, but – contrary to a two price system – without including non-market based components.

To ensure a cost-reflective real-time price, an accurate determination of the additive component is primordial. Spreading out capacity payments over all imbalanced BRPs during the time period of capacity reservation, the additive component can only be calculated using historical figures regarding the amount and magnitude of BRP imbalances. Consequently, an exact recovery of capacity payments via the additive component is out of reach. Moreover, the longer the terms of capacity reservation, the less accurate the additive component will be. Therefore, from a cost allocation point of view, capacities are preferably procured on a short term basis, for instance daily rather than yearly capacity payments. However, the impact of shorter reservation periods on competition is uncertain. On the one hand, short term capacity payments reduce market foreclosure, on the other hand they might provide incumbents with the opportunity to game on a more regular basis. On that account, the optimal length of the reservation period should be defined taking into account the impact on both cost allocation and competition. Besides, preferences of balancing service providers and TSOs should be considered. Most likely, they both prefer longer reservation periods because of the reductive effect on the risks they are faced with.

Current practices of an additive component in the real-time price include:

- In the Nordic countries, the harmonised imbalance settlement proposal to be implemented begin 2009 foresees a volume fee on consumption imbalances to recover part of the capacity payments.
- In Austria, the imbalance settlement system applied since 2006 allocates capacity costs through a component included in the real-time price that progressively increases proportional to the magnitude of the system imbalance during the settlement period concerned.

Note that in both cases, the additive component has been implemented in such way that it provides additional – but redundant or even wrong – incentives to BRPs, which should of course be avoided:

- In the Nordic countries, the additive component is only imposed on negative imbalances, which incentivises BRPs – similar to a penalty under a two price system – to be long rather than balanced.
- In Austria, the progressively increase of the additive component is achieved through addition of a non-market based component acting as a kind of “security penalty”.

2.2.Implications of market- based

The implementation of a market-based real-time design as discussed above has two major implications.

2.2.1 Need for restrictions on the amount of reserves

The allocation of capacity payments via an additive component has a negative impact on new entrants – being the most inelastic customers since they usually do not have the possibility to balance their own portfolio – rather than incumbents. Therefore, the reservation of balancing services mainly deployed for real-time energy delivery should be kept to a minimum[ii]. Consequently, in order to avoid barriers to entry, a cap should be imposed on the amount of reserves such that the share of $\text{component}_{\text{cap}}$ in the final real-time price is small compared to the marginal upward or downward regulation price. As a rule of thumb, reservations of real-time energy delivery services should only be accepted insofar as needed to compensate for the higher revenue volatility in real-time markets compared to wholesale markets and to deal with non-convexities. The appropriateness of the level of the imposed cap can be verified through monitoring whether (1) the real-time energy delivery of the reserves concerned is marginal and (2) the additive component only marginally affects the real-time price.

The actual relevance and necessity for a regulated amount of reserves is only reinforced by the fact that several TSOs' currently consider substantially increasing the amount of reserves or even building their own plants – being an extreme form of capacity payments – to ensure sufficient availability of services for real-time energy delivery purposes. A lacking confidence in the real-time market and an associated fear for a shortfall of reserves are often at the basis of these intentions. However, an over-contracting of reserves entails several negative side-effects:

- It reduces trade opportunities in the wholesale market and accordingly increases price differences between the wholesale and real-time market.
- It has a reductive effect on real-time prices – even when these should be high because of scarcity – which could finally result in a disappearance of the real-time market.
- It might increase moral hazard by granting BRPs the implicit guarantee that all imbalances can be covered by reserves procured by the TSO.

2.2.2 Infeasibility of a market-based design on a national level

Currently implemented real-time market designs across the EU often significantly deviate from the previously proposed market-based design. However, these deviations are understandable in a national context, considering market concentration and the (non)-existence of a well-functioning intra-day market. As such, concentration simply does not allow some real-time markets to function properly on a national scale. This explains why many real-time "markets" are currently more regulated than market based.

The potential infeasibility of a market-based design on a national scale implies that cross-border balancing should be implemented first and real-time market designs should only be harmonised afterwards.

3. Conclusions: impact of recommendations on wind power integration

Following the analyses in the previous Section, the use of non-market based components such as power exchange prices and penalties in the imbalance settlement should be avoided. Implementation of this recommendation positively affects wind generation in three ways. First, an abolition of penalties has a reductive effect on overall imbalance prices. Secondly, given that the correlation between system imbalance and individual wind power imbalances rises with increasing wind integration, wind generation's imbalance costs are lower under an imbalance settlement without penalties – payable only by those BRPs aggravating the system imbalance (Usuola et al., 2008). Third, strategies – as illustrated in the previous Section – to avoid short real-time positions in case of penalties are often more easily executable and profitable for conventional generation resources than for wind generation.

The implementation of a second recommendation – advising the use of an additive component to allocate capacity payments for services delivering a significant amount of real-time energy – might however have a negative impact on wind generation. The additive component mainly affects inelastic consumers like wind generators – given their limited predictability and intermittency – that have no other possibility than relying on the balancing market for their last resort energy needs. As such, wind generators are very likely to bear a significant part of the capacity payments carried out by the TSO, having an uplifting effect on their imbalance costs. However, these capacity costs are also partly caused by wind and – as indicated in Section 1 – the more wind power penetration, the less bearable for the system not to allocate these “hidden” costs to the responsible parties. Furthermore, implementation of a third recommendation capping the amount of reserves – to ensure that the share of capacity payments in the total imbalance price is marginal – dampens the increasing impact on imbalance prices.

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[i] It is important to distinguish this *additive* component from the *multiplicative* component as discussed previously in the context of two price systems. Contrary to the latter, the former is (a) cost-reflective, (b) not used for penalisation purposes and (c) not giving rise to undesirable BRP behaviour.

[ii] Note that the discriminatory impact of an additive component on new entrants can also be counteracted by the implementation of a separate imbalance settlement system for generation and load.