Refining Short-Term Electricity Markets to Enhance Flexibility

Stocktaking as well as Options for Reform in the Pentalateral Energy Forum Region

STUDY

Agora Energiewende

Microeconomix

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Preface

Dear Reader,

Throughout Europe, animated power market design discussions are going on. Although there are a lot of different approaches to market design, one consensus is emerging: It is a no-regret option to make the short-term energy markets more flexible. The reason lies in the fact that European power systems are increasingly shaped by wind and solar power, leading to more fluctuating production patterns. Thus, refinements of the design of short-term markets that contribute to system flexibility are essential.

By improving the design of short-term markets (day-ahead, intraday and balancing markets and imbalance settlement rules) – which is where the demand for flexibility is met – we can improve price formation to provide flexibility efficiently.

The Pentalateral Energy Forum (PLEF), consisting of Austria, Belgium, France, Germany, Luxembourg, the Netherlands and Switzerland, a region with a strong track record of regional cooperation and advanced power market integration, is currently working on options to make their power markets more flexible. Our study aims to contribute to the ongoing debate by identifying key market design elements that efficiently enable flexibility and further market integration.

I hope you find it inspiring and enjoy the read! Comments are very welcome.

Yours sincerely,
Patrick Graichen,
Executive Director of Agora Energiewende

Key Findings at a Glance

1. **Short-term markets in Central Western Europe are characterised by a rather inefficient patchwork of flexibility enabling and disabling design elements.** Some key design elements of intraday and balancing markets as well as imbalance settlement rules distort wholesale power price signals, increasing the cost of providing flexibility. This highlights the need to adjust key market design elements and requires continuous political momentum to coordinate efforts regionally.

2. **Current market designs are biased against demand side response and renewables.** Restrictive requirements for market participation, mainly relating to demand response and renewables, constrain the flexibility potential. In the balancing markets, small minimum bid sizes and short contracting periods would be required. A regulatory framework enabling independent aggregation should be implemented for fully tapping the flexibility potential.

3. **Balancing market rules show large differences across the region, leading to inefficient pricing in preceding day-ahead and intraday markets.** A joint balancing market design in the PLEF region with short product duration, late gate closure and marginal pricing would enable efficient cross-border competition for flexibility services. Getting the pricing right in balancing mechanisms is important as it supports efficient pricing in preceding day-ahead and intraday markets – where most of the flexibility is traded.

4. **Cross-border intraday trading needs reform to improve efficiency and enhance liquidity.** Intraday markets are critical for integrating wind and solar, as they allow for trades responding to updated generation forecasts. Today, explicit cross-border capacity allocation as well as misalignments in gate closure times across the region and differing product durations result in inefficient intraday energy and interconnector capacity allocation. Thus, harmonised rules and improved implicit cross-border allocation methods are needed, e.g. improved continuous trading or intraday auctions.

Content

Acronyms

aFRR	Automatic Frequency Restoration Reserves (also denoted secondary reserves - R2)
BM	Balancing Market
BRP	Balancing Responsible Party
CMM	Congestion Management Mechanism
DA	Day-ahead
DAM	Day-ahead Market
FCR	Frequency Containment Reserves (also denoted primary reserves - R1)
ID	Intraday
IDM	Intraday Market
mFRR	Manual Frequency Restoration Reserves (also called tertiary reserves - R3)
PLEF	Pentalateral Energy Forum
PX	Power Exchange
RR	Replacement Reserve
RT	Real-Time
vRES	Variable Renewable Energy Sources

Executive Summary

Refining Short-Term Electricity Markets to Enhance Flexibility — Stocktaking as well as Options for Reform in the Pentalateral Energy Forum Region

As Europe moves to meet its long-term energy and climate targets, its power systems will be increasingly shaped by wind power and solar photovoltaics (PV). A unique characteristic of these renewables is that power generation fluctuates strongly based on weather patterns. Accordingly, future power systems will need to be capable of integrating power from renewables, flexibly ramping production from conventional power sources up and down depending on need.

To manage this "flexibility challenge", the introduction of refinements to the regulatory design of short-term electricity markets represents an important "no-regret" option for policymakers and regulators. By improving the design of short-term markets – which is where the demand for flexibility is met – we can improve pricing mechanisms for supplying flexibility while simultaneously easing the general burden of ensuring sufficient flexibility. Indeed, experts believe regulatory changes that contribute to system flexibility are essential for ensuring system adequacy in coming years.

With the aim of isolating the key market design elements that enable the efficient provisioning of flexibility, Agora Energiewende commissioned CE Delft and Microeconomix to conduct an in-depth quantitative and qualitative analysis. Our study focused on the Pentalateral Energy Forum (PLEF) region, a set of countries with a track record of regional cooperation, advanced power market integration, and a relatively high level of physical interconnection. The study's main findings are presented below.

The role of short-term markets in supplying flexibility

The EU aims to generate at least 27 percent of its energy from renewables by 2030, a target that translates into a 45 to 53 percent share of renewables in the power sector.[1] This means the next 15 years will see roughly a doubling of the share of RES-E in Europe's power systems.[2] According to current trends, PV installations and onshore wind turbines will by far make up the largest share of the newly installed renewable energy capacity. This increasing share of wind and PV will, in turn, induce a fundamental transformation of our power systems. Overall, power systems will need to become more flexible both on the supply and demand side.

Figure ES 1 illustrates this need for flexibility. In the case presented, the wind dies down in tandem with a drop in the generation of solar power. Thus, controllable power plants have to cover a major portion of the demand within a few hours.[3]

Short-term electricity markets are responsible for ensuring flexibility is supplied by dispatchable conventional generation, demand side response, and storage. Market arrangements vary by country, but typically there are three different short-term markets: the day-ahead market (DAM), the intraday market (IDM), and the balancing market (BM).[4]

1 See the Commission Impact Assessment on a policy framework for climate and energy in the period from 2020-2030 (COM SWD (2014) 15 final of 22.1.2014) for scenarios in line with a 40 percent GHG emission reduction.

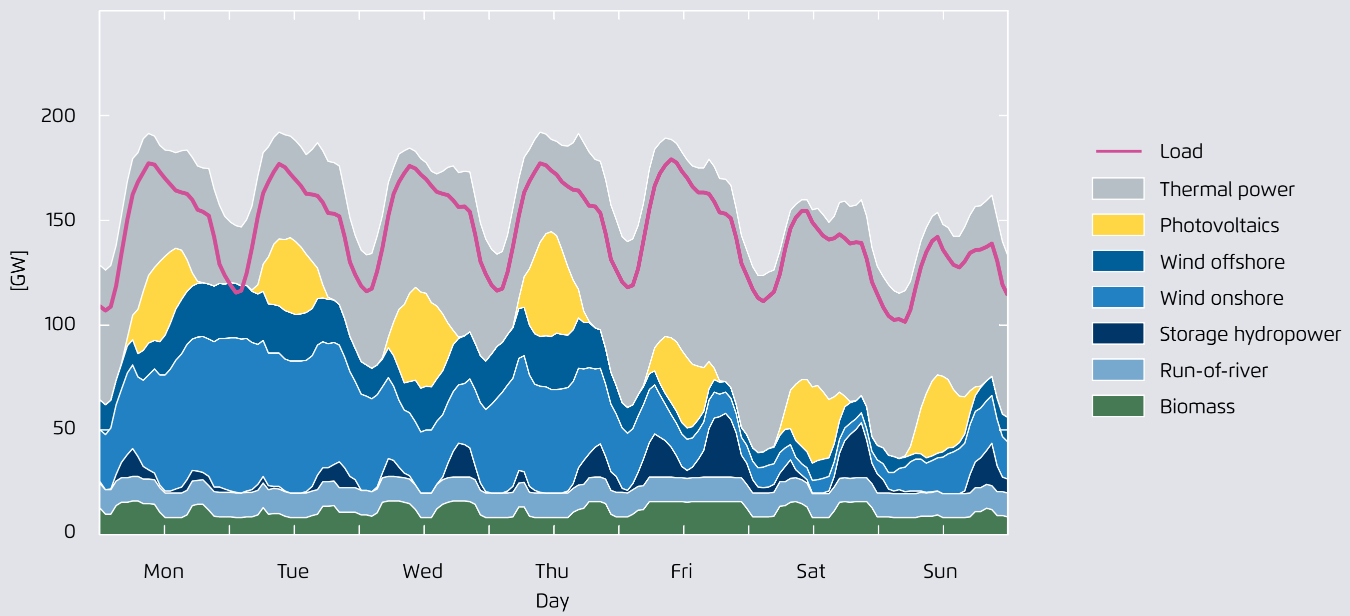
2 The 2015 share of renewables in gross electricity consumption was 28.6 percent (Agora Energiewende (2016): Energy Transition in the Power Sector in Europe: State of Affairs in 2015. Review of the Developments and Outlook for 2016.)

3 Fraunhofer IWES (2015): The European Power System in 2030: Flexibility Challenges and Integration Benefits. An Analysis with a Focus on the Pentalateral Energy Forum Region. Analysis on behalf of Agora Energiewende.

4 Also the incentives given to market actors to balance themselves before real-time (through the so-called imbalance settlement mechanism) are important for pricing in the energy and balancing markets and thus flexibility provision. We will discuss this in more detail below.

Electricity generation* and consumption* in the PLEF region in a week in late summer 2030 (calendar week 32).

Figure ES 1



Fraunhofer IWES (2015)

Public discussion concerning flexibility often focuses on balancing markets, as these markets explicitly remunerate actors who provide flexibility. However, all short-term market segments play a role in providing flexibility. While day-ahead and intraday markets do not trade a product called "flexibility" (only energy products are exchanged in these markets), flexibility is remunerated in these markets as well.

The DAM remunerates flexibility when there are high variations in residual demand, as some less flexible units cannot ramp up and down to follow these variations. Intraday markets integrate new information that was not available at the day-ahead stage and reflect the fact that flexible capacity becomes scarce moving from day-ahead to real-time. Thus, as only flexible capacity can participate in intraday and balancing markets (due to shorter product lengths and planning horizons), there is additional remuneration of flexible capacity from the DAM to the IDM and BM. In conclusion, the demand and supply of flexibility are (implicitly) spread over all short-term market segments. Furthermore, all market segments have a role in the coordination and remuneration of flexibility.

To ensure the efficient supply of flexibility, short-term market prices should reflect the real-time value of electricity. In certain instances, existing market arrangements are in need of reform to ensure efficient price-formation mechanisms.

How market design affects pricing and provision of flexibility in electricity markets

Market prices are fundamentally driven by supply and demand conditions. However, in short-term electricity markets, price dynamics are strongly affected by the design of the market, i.e. by the specific rules that govern its function. Essentially, the adopted market design creates specific incentives for market actors to balance themselves before real-time.

In this study we use three different metrics to assess existing regulatory arrangements in PLEF countries based on market design theory. While we focus on individual countries, these metrics are also useful for assessing rules that govern cross-border market integration. These three metrics are:

- *Market access:* To what extent can power markets be accessed by different market actors/ by different demand or supply side technologies?
- *Market completeness*: Can electricity be traded along a "continuous" set of markets – from "the far future" to "real-time"?
- *Market pricing*: How are clearing prices formed and to what extent is pricing constrained by market rules?

The market design should set a series of boundary conditions that enable efficient pricing, thus allowing markets to allocate resources efficiently. In our view, the selected market design should uphold the following three principles, as they are essential for efficient market prices:

- *Marginal pricing principle*: If the price of a good/service is set at its marginal cost/value to society, then the market players will act efficiently: they will produce the good/service if their internal marginal cost is lower or equal to that price, and they will consume the good/service if the internal marginal benefit is higher or equal to that price. Assuming that the market-wide generation cost function increases with the level of production, and that prices follow the marginal pricing principle, it is expected that prices increase when the market is tighter and decrease when the market is well supplied.
- *Opportunity cost pricing principle*: Some resources can be used to produce several goods or services (e.g. they can either sell energy on the DAM or provide balancing services to the BM). Efficient pricing for optimal allocation of these resources needs to include the opportunity cost, i.e. the foregone benefit of not producing alternative goods/services (as a simplified example: If a resource is used for the balancing market it cannot sell energy on the DAM). Thus, optimal coordination necessitates the inclusion of opportunity costs in prices.
- *No-arbitrage principle*: This principle asserts that prices for perfect substitute products should be equal, and that, accordingly, systematic arbitrage opportunities should not arise in efficient markets. It is also known as the *law of one price*. In the electricity market, several products/goods can be seen as at least partially substitutable. The arbitrage between different electricity markets contributes to efficient allocation across these markets, both over time and space. Arbitrage ensures that least-cost alternatives available in different markets are utilised, rather than their substitutes.

A snapshot of current market designs: Key market design parameters show a broad range of implementation specifications[5]

Regarding the first market design metric, *market access*, Table ES 1 shows that short-term markets in PLEF countries typically allow **demand side market participation**, usually relating to industrial electricity consumption, as well as aggregated demand side market participation.

However, the **product duration** (i.e. how long a product has to be delivered) can have relatively restrictive consequences for market participation, especially in balancing markets. The longer the contracting (capacity) or delivery periods (energy), the more this restricts the potential number of providers. As Table ES 2 shows, product duration for balancing energy are in the range of 15 minutes to 48 hours. Furthermore, operational reserves are contracted from weekly products to yearly products in most PLEF countries. Daily products are a rare exception. Longer contracting requirements are particularly restrictive, as both renewables and demand response (or small-scale storage) cannot be committed over longer time periods. This restricts the flexibility potential – as shown here for balancing markets.

5 The market design specifications shown in this study depict the situation as of 2015. Market design specifications are characterised by their potential to enable efficient flexibility provisions by means of a traffic light colour coding: Green-coded cells are enabling specifications, red-coded cells are disabling specifications. Yellow-coded cells are disabling, albeit to a lesser extent.

Demand side market access in the reserve markets (primary reserves (R1); secondary reserves (R2); tertiary reserves (R3)) in the PLEF countries in 2015. Note that demand side market access in the day-ahead and intraday markets is allowed across the PLEF region. Table ES 1

	Load				Aggregate load			
	R1	R2	R3	Special DR products	R1	R2	R3	Special DR products
Austria	yes	yes	yes	n.a.	yes	yes	yes	n.a.
Belgium	partial (R1 Load share max. 33%)	no	partial 10 per-cent (R3 DP) + 40% (R3 ICH)	n.a.	partial (R1 Load share max. 33%)	no	partial 10 percent (R3 DP) + 40% (R3 ICH)	n.a.
France	yes	yes	yes	yes	yes	yes	yes	yes
Germany	yes	yes	yes	yes	yes	yes	yes	yes
The Netherlands	yes	yes	yes	n.a.	yes	yes	yes	n.a.
Switzerland	yes	yes	yes	n.a.	yes	yes	yes	n.a.

CE Delft and Microeconomix based on TSO information and SEDC (2015).
Abbreviations: R1 Load = R1 interruptible load (FCR), R3 DP (Dynamic Profile) = interruptible load – max 2h interruptions (mFRR), R3 ICH = Interruptible load – 4h, 8h or 12h interruptions (mFRR), DR = Demand Response.

Product duration requirements imposed in the reserve markets in the PLEF countries in 2015. Note that product duration requirements for the DAM and the IDM are typically set at 1 hour, with the exception of the Austrian DAM and the Austrian, German, and Swiss IDMs that facilitate trading of 15 minute products as well. Table ES 2

	Temporal product resolution energy bids			Contracting period for operational reserves capacity bids			
	R1	R2	R3	R1	R2	R3	Spec. DR prods.
Austria	15 mins	12 hrs (WD), 48 hrs (WND)	4 hrs	1 week	1 week, 1 day	1 week	n.a.
Belgium	15 mins	15 mins	15 mins, 4 hrs (IL)	1 month	1 month	1 year (1 month for 10% fraction)	n.a.
France	30 mins	30 mins	30 mins	n.a. [6]	n.a. [7]	1 week or 1 year [8]	1 year (IL)
Germany	15 mins	12 hrs (WD), 48 hrs (WND)	4 hrs	1 week	1 week	1 day	1 month
The Netherlands	15 mins	15 mins	15 mins	1 week	1 year	1 year	n.a.
Switzerland	15 mins	15 mins	4 hrs	1 week	1 week	1 day	n.a.

CE Delft and Microeconomix based on TSO information. Abbreviations: WD = weekday, WND = weekend, IL = interruptible load.

6 The case of R1 and R2 is quite different in France since producers (above a certain size) have an obligation to reserve some capacity. On D-1, the TSO computes the required R1 and R2 and apportions these volumes among producers based on their expected generation (for instance, a producer who does not expect to produce is not required to have some reserved capacity). Producers obliged to provide reserves can buy needed capacity in a "secondary" market. Thus, there is not an auction for capacity as in other countries, but the obligation for a contracted reserve is defined one day ahead and a price can arise in the secondary market.

7 See previous footnote.

8 The auction for the reservation is done Y-1 and considers the whole year but bids are made on a weekly basis.

Alignment of delivery periods in short-term electricity markets in the PLEF countries in 2015. Table ES 3

	Temporal product resolution energy bids				
	DAM	IDM	R1	R2	R3
Austria	60 mins, 15 mins	60 mins, 15 mins	15 mins	12 hrs (WD), 48 hrs (WND)	4 hrs
Belgium	60 mins	60 mins	15 mins	15 mins	15 mins, 4 hrs (IL)
France	60 mins	60 mins	30 mins	30 mins	30 mins
Germany	60 mins	60 mins, 15 mins	15 mins	12 hrs (WD), 48 hrs (WND)	4 hrs
The Netherlands	60 mins	60 mins	15 mins	15 mins	15 mins
Switzerland	60 mins	60 mins, 15 mins	15 mins	15 mins	4 hrs

CE Delft and Microeconomix based on TSO information. Abbreviations: WD = weekday, WND = weekend, IL = interruptible load.

To illustrate the second market design metric, *market completeness*, Table ES 3 shows that **delivery periods** are not aligned well across the PLEF short term markets. The main difference between countries relates to the increasing temporal granularity when moving to real-time, i.e. shortening of the settlement period of the products traded when moving from day-ahead to balancing markets. Clearly, when the imbalance settlement period (ISP) involves 15 minute values, while such products are not traded in the day-ahead and intraday markets, these markets allow only for partial hedging of imbalance exposures. Differences also appear across borders: ISPs are set to 15 minutes in most PLEF countries, while the French ISP is set to 30 minutes. Any of these differentials imply that frictionless trading cannot be achieved, leading to inefficiencies.

To illustrate the third market design dimension, *market pricing*, the **pricing mechanisms** in the balancing markets typically remunerate providers of balancing services on a pay-as-bid basis. Only the Netherlands remunerates secondary and tertiary balancing energy through marginal pricing. Pay-as-bid pricing is generally thought to induce inefficiencies as it is likely to diverge from marginal pricing. Pay-as-bid remuneration incentivises inframarginal bidders to bid up to the expected marginal price in order to capture inframarginal rents. The resulting bidding induces inefficiencies in the allocation of resources, i.e. in the associated dispatch of supply and demand-side technologies.

Pricing mechanisms in the balancing markets in the PLEF countries in 2015. Table ES 4

	Settlement price for balancing energy	
	R2	R3
Austria	Pay-as-bid	Pay-as-bid
Belgium	Pay-as-bid	Pay-as-bid
France	Pay-as-bid	Pay-as-bid
Germany	Pay-as-bid	Pay-as-bid
The Netherlands	Pay-as-cleared	Pay-as-cleared
Switzerland	Pay-as-bid	Pay-as-bid

CE Delft and Microeconomix based on TSO information.

Efficiencies and inefficiencies are visible in current market prices

With current designs, the short-term markets in the PLEF region generally give adequate price signals for the remuneration of flexibility, although some specific market segments give contradictory signals.

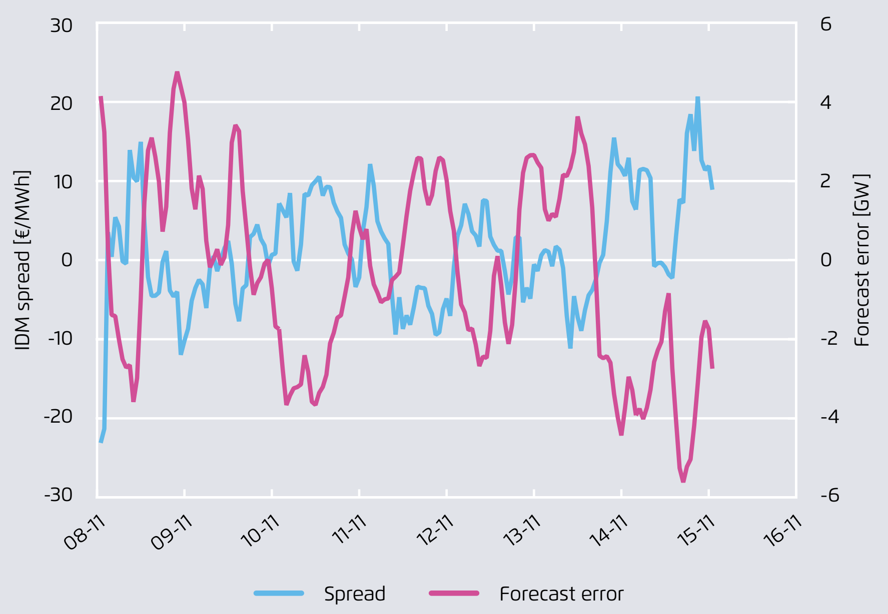
Remuneration on the **day-ahead market** increases slightly if more flexibility is required to serve the load. Also, the **intraday market** shows correlations with flexibility demanded to correct, for example, adjustments in the day-ahead vRES forecasts (particularly for wind). In this way, flexibility is remunerated through the intraday market. Depending on updated information on wind forecasts, intraday prices are generally higher or lower than day-ahead prices. For instance, in the event of a day-ahead overestimation of renewable production or underestimation of demand, additional power will be demanded on the intraday market, and intraday prices will be higher than day-ahead prices (or vice versa). Figure ES 2 illustrates the results for Germany.

The figure presents the difference between the intraday and day-ahead prices (the so-called intraday spread) and the day-ahead wind power forecast error for a period of seven days. The intraday spread shows strong correlation with the day-ahead wind forecast error, reflecting corrective trades on the intraday market.

However, we should note that *liquidity issues* in some PLEF intraday markets induce inefficiencies in price discovery and system allocation and dispatch.[9] Efforts seeking to increase liquidity in such instances represent a good market design reform for improving efficiency. Various measures can improve liquidity, such as intraday market coupling. Efforts to improve liquidity should be assigned high priority in the coming period.

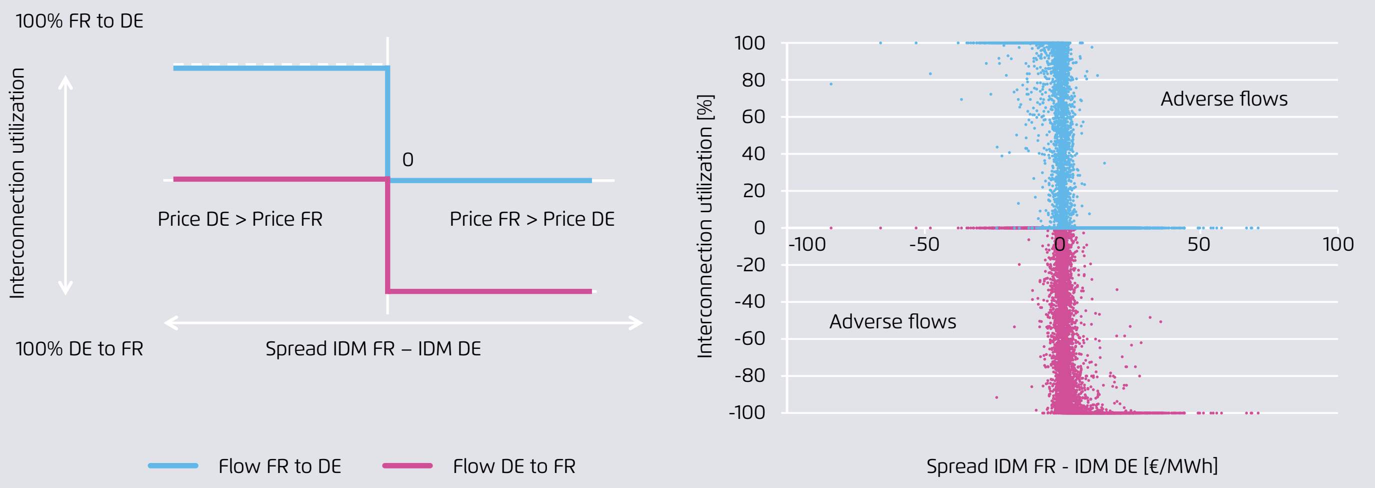
9 The German intraday market is an exception as it shows the highest liquidity in the PLEF region. Some 6% of German gross electricity demand were traded on the intraday market in 2015 (Some 50% of demand were traded on the German day-ahead market). Source: Agora Energiewende (2016), EPEX Spot (2016)

IDM spread (defined as intraday minus day-ahead price) vs. day-ahead wind forecast error (defined as actual wind generation minus day-ahead forecast) in Germany in November 2015. Figure ES 2



CE Delft and Microeconomix based on PX and TSO data

German-French IDM spreads (defined as French minus German intraday price) vs. cross border flows in 2014[10] Figure ES 3



CE Delft and Microeconomix based on PX and TSO information

Optimising cross-border intraday trade options is not only important for improving liquidity, however. It is also crucial for efficient flexibility provision and for minimising system costs. For example, current arrangements prohibit full consistency between cross-border power flows and cross-border intraday price differences. As an illustrative example, Figure ES 3 shows the nominated intraday cross-border capacity and the intraday cross-border price spread between France and Germany.

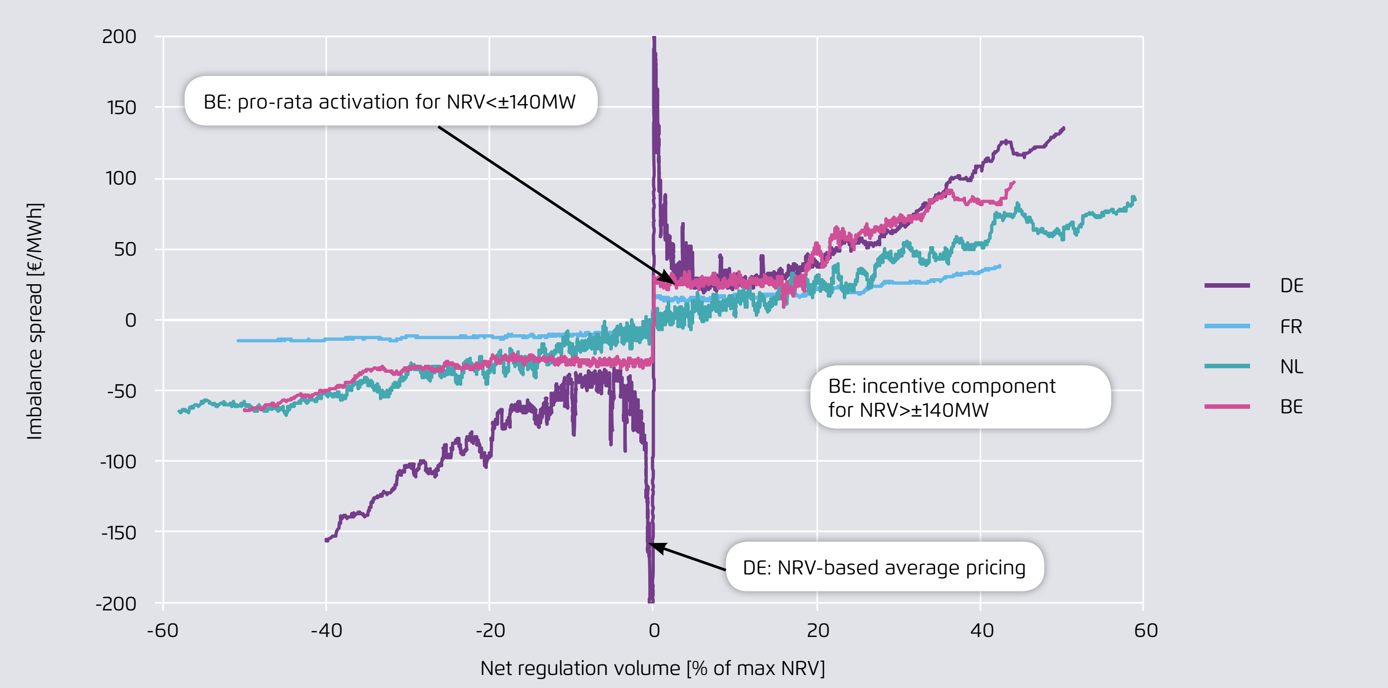
In case of efficient cross-border intraday trading arrangements, one should expect:

- a full utilisation of the available cross-border capacity if a non-zero cross-border intraday price spread prevails; and
- nominated cross-border trades occurring from the low price to the high price country.

These two assertions are represented in the left-hand side Figure ES 3. The right-hand side of the figure shows the actual intraday interconnector utilisation between France and Germany in 2014. Divergences from the expected pattern (which is shown on the left) indicate that cross-border capacity is inefficiently utilised. Indeed, one can see from the right side of the figure that in many instances, the interconnection is not fully used, although a non-zero cross-border intraday price spread prevails. Worse, interconnector capacity is occasionally used by market actors to deliver power flows from the high price to the low price country. This means that flexibility is often not provided at least cost. These results for the French-German border may be explained by the simultaneous use of explicit and implicit allocation for cross-border transmission capacity. Other potential causes of this inefficiency may be found in the difficulties associated with designing an efficient implicit market coupling system for continuous trading and in the lack of trading platforms with centralised pricing of intraday cross-border transmission capacity. Also, available cross-border transmission capacity is offered free of charge in the intraday timeframe, which contributes to inefficient allocation and flexibility provision.

10 For this comparison 2014 data were used, as in 2015 the cross-border capacity data were no longer readily available with the introduction of flow-based market coupling.

BM spread (defined as imbalance settlement price minus DAM price) vs. net regulation volume (NRV) in DE, FR, NL, and BE (2015). Figure ES 4



CE Delft and Microeconomix based on TSO data

Abbreviation: NRV = Net Regulation Volume

Balancing markets typically fail to adhere to the pricing principles cited above. Accordingly, they exhibit clear inefficiencies with a view to the remuneration of flexibility and system-resource allocation. If balancing markets diverge from optimal pricing principles, this means that also **imbalance settlement prices** will not fully reflect the real-time value of power, undermining efficiency.[11] These inefficiencies stem from balancing market design features, including pay-as-bid remuneration, pro-rata balancing deployment, regulated tariffs, delays in publication of imbalance prices, and the methods used to determine imbalance prices.

To test pricing efficiency in the balancing market/imbalance settlement segments, we compare the spread between imbalance settlement prices and day-ahead prices to the net regulation volume (NRV)[12] (see Figure ES 4). The imbalance settlement prices reflect the cost of balancing the system for the market parties.

As expected, the activation of upward regulation induces a positive spread, whereas downward regulation induces a negative spread. Given that the imbalance spread increases with net regulation volume (NRV) it can be concluded that the balancing markets remunerate flexibility in the assessed countries, albeit to a differing extent, as the spread profiles differ widely from country to country. The steeper the spread profile as a function of the deployed regulation volume and the closer the imbalance price reflects the real-time value of power, the higher the incentive for market actors to provide flexibility to the system, or to minimise one's

11 Balancing market prices drive the imbalance costs for market parties on the basis of their respective imbalances. Imbalance prices thus give an incentive to market parties to balance their respective portfolios in the day-ahead and intraday markets.

12 The difference between upward regulation volume (balancing power which is injected into the system if real-time demand unexpectedly exceeds real-time supply) and downward regulation volume (balancing power which is withdrawn from the system if real-time supply unexpectedly exceeds real-time demand) during an imbalance settlement period.

own imbalance (e.g. through corrective trades in the intraday market or optimisation its portfolio of assets).

The French spread profiles show relatively low price sensitivity to increasing NRV volumes. The Belgian prices show a comparably flat price profile between ±15 percent of the maximum NRV, while increasing more steeply for larger volumes. German imbalance spreads are very high for low volumes, but decrease steeply as NRV levels rise. Similar to Germany, in France and Belgium non-zero spreads between the imbalance price and the day-ahead price occur for very small NRV volumes. The Dutch spread profile follows the expected relation between NRV and imbalance spread, that is to say an increasing function with a zero imbalance spread for a zero NRV.

The observations can be explained as follows. The imbalance spreads are strongly affected by the imbalance settlement pricing mechanisms (i.e. whether they are based on net or gross regulation volumes, or average versus marginal pricing). The activation mechanisms for balancing energy bids also exert a strong influence on prices (i.e. parallel activation of all bids ["pro-rata activation"] versus merit order activation). In the interest of efficient flexibility supply, the two best practices for balancing market pricing are marginal pricing[13] and merit order activation. However, balancing markets in the PLEF region diverge considerably in this area.

What does current pricing in the short-term PLEF electricity markets tell us about options for improving the market design and options for further market coupling?

Based on the analysis above, it can be concluded that short-term markets in the PLEF countries show room for further refinements with a view to the efficient supply of flexibility. Beyond improving efficiency, improvements to existing regulatory rules could also enable further market integration between countries.

The current market environment is not always fully technology neutral due to specific **requirements for market participation**. This predominantly relates to the ability of *demand-side response (DSR)* options to access the market. Though DSR has long been recognised as a resource for short-term electricity markets to function effectively, PLEF countries have traditionally failed to account for DSR in their short-term market arrangements, most notably in their balancing markets. While many balancing markets have been opened up for large-scale (aggregate) demand side participation in recent years, it appears that crucial enabling factors have not yet been accounted for in all PLEF markets. The related activity of *independent aggregation*, which is believed to be an enabling factor for small scale flexibility and DSR activation at large, still remains only marginally institutionalised, for the roles and responsibilities of different market actors have not yet been defined in most PLEF markets. When assessing *product specifications* from the perspective of accessibility, *product duration* is a key aspect of balancing market design in need of attention. Specifically, product lengths should be shortened to unlock flexibility from new sources.

Looking at each specific segment of the PLEF short-term markets, the following can be observed.

First, **balancing markets** show a wide range of differences, both with respect to fundamental design elements such as pricing mechanisms, as well as with regard to more detailed provisions related to market access for several increasingly relevant flexibility categories. Furthermore, we can also see that market designs differ from some economic principles creating frictions in general short-term market trading.

In particular, *marginal pricing* does not typically apply in the PLEF balancing markets, neither in case of balancing energy nor in case of imbalance settlement pricing (notably in systems with dual pricing). Hence, efficient allocation is negatively affected (also in preceding intraday markets). Critically, the balancing mechanisms show a wide range of

13 Charging market actors with average prices induces inefficiencies, as it socialises the marginal cost of imbalances, typically inducing only moderate price increases at higher system imbalances.

pricing methodologies. *Pay-as-bid mechanisms* dominate the *balancing energy pricing* mechanisms in PLEF countries. With regard to *imbalance settlement pricing*, fundamentally different pricing methodologies occur across the region. A *single imbalance pricing mechanism*[14] is implemented in several PLEF countries, while *dual imbalance pricing*[15] is in place in others. Furthermore, *average pricing methodologies* for imbalance prices have been implemented in several of PLEF countries, in contrast to marginal pricing. These pricing provisions distort the process of price discovery, undermining the accurate cost valuation of flexibility. It is important to note that balancing market and imbalance prices should reflect the real-time value of electricity. Yet as shown above, existing pricing provisions often prevent this. Getting the pricing right in balancing mechanisms is important, as it also supports efficient resource allocation in the preceding day-ahead and intraday markets – where most of the flexibility is traded.

The foregoing recommendations align in several respects with the provisions set forth in the Network Code on Electricity Balancing.[16] The Network Code calls for marginal pricing (pay-as-cleared) for balancing energy and for single pricing for imbalance settlement. Furthermore, imbalances are to be settled at a price that reflects the real-time value of energy.

Several aspects, such as *product duration* and *gate closure* for operational reserve capacity, impose a significant hurdle for the supply of flexibility, both for new categories of flexibility provision as well as for conventional flexibility providers (albeit to a lesser extent). Notably, the *contracting of operational reserve capacity* stands out. Currently, such commitments occur well ahead of real-time and as such create significant uncertainty for market actors, e.g. with regard to the foregone value of the pre-contracted capacity. Accordingly, *increasing contracting frequency, shortening contracting period* and *shortening gate closure times* would allow for enhanced valuation of the product and notably the foregone value of the capacity in other market segments. Such measures would allow for more accurate pricing by flexibility providers, enhance flexibility price discovery and reduce the risks involved for flexibility providers.

These findings align qualitatively with several of the provisions in the Network Code on Electricity Balancing. It has to be noted that existing provisions in some PLEF countries already go beyond the minimum requirements of the Network Code.[17]

According to our analysis, **day-ahead** and **intraday markets** are more closely aligned with the principles of efficient pricing. The main exception in this respect may be found in the linkage between *cross-border energy trading* and *cross-border transmission capacity allocation* in the intraday timeframe. While shifts in vRES production forecasts after the day-ahead market induce increasing demand for corrective trading in the intraday timeframe, cross-border intraday market trading would offer significant potential for such corrective actions at least cost, as it would minimise both the exposure of market parties to imbalance payments and the deployment of balancing energy by the TSOs. However, existing cross-border capacity allocation arrangements are not perfectly geared to enable liquid intraday cross-border trading.

14 Single imbalance pricing means that imbalances of market actors in the same direction as the overall system imbalance are settled at the same price as imbalances of market parties that are in the different direction as the overall system imbalance.

15 Dual imbalance pricing means that different imbalance prices apply for market actors' imbalances in the same direction as the overall system imbalance and for market actors' imbalances in the different direction as the overall system imbalance.

16 Annex II to Recommendation of the Agency for the Cooperation of Energy Regulators No 03/2015 of 20 July 2015 on the Network Code on Electricity Balancing.

17 The Network Code foresees that the procurement of balancing capacity shall be done as close to real-time as possible, while contracting should be done for a maximum of one month in advance of the provision of the balancing capacity. Furthermore, the contracting period is to have a maximum period of one month, and balancing energy gate closure time are to be as close as possible to real-time. Lastly, the Network Code calls for balancing energy gate closure after the intraday cross zonal gate closure time for all balancing energy bids.

Implicit allocation has already been introduced in a number of cases, but often partially and alongside explicit allocation. The clearly advantageous approach of *aligning ID cross-border capacity allocation with IDM energy trading* unequivocally is often hampered. Clear benefits could also be derived by aligning intraday products with balancing market products when the respective energy products show different lengths (typically hourly for intraday and quarter-hourly for balancing). It should be noted that improved cross-border intraday trading not only improves the supply of flexibility in a timeframe critical to enable corrective trades, but has the potential to improve liquidity and efficiency in the intraday market as a whole. Thus, we believe it is extremely important to better align cross-border capacity allocation and energy trading (e.g. the goal of the XBID intraday market coupling project[18]) while also efficiently including the value of cross-border transmission capacity in the cross-border intraday market trades. Since the impact of vRES generation is typically smoother in a larger geographical contexts, these market changes can be expected to significantly add to short-term market resilience.

Conclusions: Pathways for robust market design

In order to facilitate the large scale introduction of renewable energy in electricity markets, European countries require a robust market design that promotes the effective allocation of flexibility. In this report, we assessed how efficient PLEF countries are in allocating flexibility on the basis of several fundamental principles for efficient pricing and allocation.

One finding of our review is that balancing markets are the market segment with the greatest divergence between countries in terms of design and implementation and with the largest efficiency improvement potential. Several PLEF countries currently do not have rules for marginal pricing in place – one requirement that is called for in the Network Code on Electricity Balancing. Often balancing energy is remunerated based on pay-as-bid pricing, and pro-rata activation mechanisms are used. Imbalance settlement pricing is often based on averaging balancing market prices and, hence, unlikely to reflect the real-time value of energy. This is a clear and pressing problem, as efficient pricing in the balancing markets and imbalance settlement is important to facilitate efficient resource allocation in the preceding day-ahead and intraday markets (where most of the flexibility is traded). The implementation of provisions in this regard contained in the Network Code on Electricity Balancing is likely to add significantly to the overall efficiency of flexibility allocation. This, in turn, can be expected to augment the resilience of short-term markets as renewable energy is introduced on a large scale.

Intraday market play a critical role in flexibility, linking the day-ahead and balancing markets. The intraday market facilitates a critical aspect of non-dispatchable renewable energy integration (e.g. solar PV and wind), as it allows for scheduling adjustments to respond to updated information about production forecasts. While the allocative efficiency in the intraday timeframe is significantly affected by the balancing market design – reinforcing the need for a robust balancing market design – it is also strongly affected by misalignments between the intraday energy market and intraday cross-border transmission capacity allocation. A better alignment based on improved implicit cross-border allocation (including the value of cross-border transmission capacity) – is not only likely to increase efficiency, but also enhance liquidity, an issue that currently hampers several of the PLEF intraday markets.

18 The XBID project aims to develop a unified intraday cross-border trading platform for continuous trading and implicit allocation of cross-border capacity across Europe.

1 Introduction

The European Union is committed to the broad-based decarbonisation of its economy, and has adopted ambitious targets for reducing greenhouse gas emissions. By 2050, in fact, the EU hopes to reduce emissions by as much as 80-95 percent below their 1990 levels. The European electricity sector will play a pivotal role in fulfilling these targets. While the EU's 2020 Climate and Energy Package was an important step on the road to decarbonisation[1], in October 2014, the European Union reaffirmed its commitment to further decarbonisation by adopting the 2030 Energy and Climate Policy Framework. The framework foresees an EU-wide target of 27 percent for renewable energy deployment and a 40 percent reduction in greenhouse gas emissions.

The 2020 targets foresee expanding the share of renewable energy sources (RES) in the electricity sector to approx. 34 percent, compared to its current share of 28.6 percent in 2015.[2] By contrast, the more recent targets for 2030 have been estimated to correspond to 45-53 percent[3] RES deployment in the European electricity sector.

Electricity markets in the region of Central West Europe (CWE)[4] have in recent years shown early signs of fundamental transformation due to increasing levels of renewable energy deployment. In several European Member States, electricity supply dynamics across the region have changed in part due to the expanded use of non-dispatchable, or variable, renewable energy sources (vRES) such as wind and solar PV. New patterns in wind and solar PV production have given rise to concerns regarding system security and network operation, and have also sparked discussions regarding system adequacy. With vRES making up a greater share of the power supply, residual load levels typically served by price-setting conventional generation have been in decline. This phenomenon, together with very low CO_2 prices in the EU Emissions Trading Scheme as well as low coal prices, has resulted in depressed market prices.[5] With the expansion of vRES, variability as well as the potential for forecast errors in short-term scheduling has increased, and this in turn has posed a challenge for system security and network operations. A need has arisen for better responsiveness in facilities generating dispatchable energy and controllable load.

With European power generation patterns poised on the brink of fundamental change as a result of increased wind and solar PV deployment, there is a general acknowledgement that the design of the market must be refined in order to assure system flexibility and reliability. Indeed, market reform debates are currently underway in countries that belong to the Pentalateral Energy Forum (PLEF), although the concerns driving these debates and the sense of urgency with which they are conducted differ from country to country. While some Member States have yet to firmly establish their position on the need for capacity remuneration mechanisms (CRMs) as a tool for assuring system adequacy, others have already adopted measures for CRM imple-

1 Among a broad set of measures, the package includes a series of energy policy targets for 2020 known as the 20-20-20 targets. These targets involve a 20 percent greenhouse gas emission reduction, meeting 20 percent of energy needs by renewables, and a 20 percent increase in energy efficiency by 2020.

2 Agora Energiewende (2016): Energy Transition in the Power Sector in Europe: State of Affairs in 2015. Review of the Developments and Outlook for 2016.

3 EC (2014): Impact Assessment Accompanying the Communication: A policy framework for climate and energy in the period from 2020 through 2030.

4 We use the term "CWE" synonymously with the Pentalateral Energy Forum (PLEF) region. The PLEF comprises Austria (AT), Belgium (BE), Switzerland (CH), Germany (DE), France (FR), Luxemburg (LU), and the Netherlands (NL).

5 Depressed wholesale prices are clearly an indication of a deteriorating investment climate for generation capacity. At the same time, they are sometimes characterised as indicators of an impending shortage in capacity, rather than a welcome incentive for reduction of overcapacity (see Agora Energiewende / RAP (2015): The Market Design Initiative and Path Dependency: Smart retirement of old, high-carbon, inflexible capacity as a prerequisite for a successful market design; and Agora Energiewende (2016): The Power Market Pentagon: A Pragmatic Power Market Design for Europe's Energy Transition).

mentation. Meanwhile, other countries have been focusing on the energy-only market model as a central instrument for ensuring system adequacy. Nonetheless, all countries generally acknowledge that a current "no-regret" option is to refine the design of the short-term market by adopting changes that mitigate flexibility requirements while also improving flexibility.[6] Short-term electricity markets, including the day-ahead market (DAM), intraday market (IDM), and balancing market (BM), play a critical role in this regard, as flexibility supply and demand manifest most immediately in these markets.

This study, therefore, seeks to establish the most relevant next steps that might be taken for the reform and greater integration of short-term markets in the PLEF region. In the following, we assess key differences in market design between participating countries with a view to providing flexibility, and compare these elements with design options or "best practices" in the PLEF markets. Moreover, we highlight options for the further coupling of short-term markets.

6 Further coupling of short-term markets across borders and balancing zones as well as linking the different segments (day-ahead, intraday, and balancing markets) may reduce flexibility requirements, mobilise flexibility provision, and provide more accurate reflection of the real-time value of energy and balancing resources.

2 The Flexibility Challenge

As a first step in establishing the role of short-term markets in supplying flexibility, this section characterises what sort of flexibility is required in short-term electricity system planning. In the following, we discuss the impacts of variable renewable energy and the need for flexibility resulting from these impacts (2.1). We then provide a more detailed characterisation of the challenges to greater flexibility (2.2). Finally, we describe the challenges linked to operational management in electricity system planning (2.3).

2.1 Variable Renewable Energy Sources and Flexibility

Wind and solar PV are often referred to as variable renewable energy resources (vRES), or intermittent resources. Their intermittent character differs markedly from the more stable nature of the resources used in conventional generation, such as dispatchable fossil fuel-based production or (pumped) storage hydroelectric plants. This intermittent character is key for an understanding of how vRES operate. Below are three critical aspects that differentiate vRES from conventional sources:

→ 1. **Large and speedy variability of available capacity:** Production is limited by the availability of natural resources – by wind speed and duration and solar irradiance; this imposes a natural limit on output that varies significantly and quickly over time.

→ 2. **Limited controllability:** In principle, vRES production can be restricted when wind and solar irradiance are non-zero. This means output can be modulated up and down depending on need. However, vRES are generally deployed at full output whenever wind and solar irradiation are present, not only because this production comes at virtually no marginal cost but also because, for the most part, today's subsidy schemes bring additional revenues that are both time-independent and volume-based. Thus, technical control features are generally only in place at modern, large-scale installations. As a result, vRES production profiles are typically driven by weather conditions rather than active output management.

→ 3. **Uncertainties:** vRES resources impose a forecasting challenge to power systems management, given that production forecasts on the relevant planning timescales are subject to significant forecast errors.[7]

Variability, controllability, and uncertainty are not new in power system management. Classically, power system management is faced with the challenge of serving a variable load profile that is not perfectly predictable and the potential of power plant failure. Accordingly, there has always existed the need to develop methods for reliable system operations that can handle variability and plan for uncertainty. Modern power system management methods address these needs in a variety of ways, including the application of advanced forecasting techniques, detailed mathematical optimisation methods for planning and scheduling of production, and the maintenance of adequate levels of short-term reserves in order to allow for corrective action in real-time.

These methods have allowed for the effective integration of vRES. Given that vRES are essentially deployed whenever possible, the forecast vRES production profile is typically taken as an input to generation planning and scheduling . The forecast *residual load*,[8] which is defined as forecast load minus wind and solar PV generation, thus remains to be served by conventional dispatchable production facilities. The impact of vRES is reflected in the residual load profile to the degree that residual load shows increasing variations and forecast errors.

7 Forecast errors decline significantly moving forward from day-ahead planning, approaching levels comparable to day-ahead load forecast errors in the last hours preceding real-time.

8 The literature on flexibility and flexibility requirements relating to large-scale integration of vRES often uses the term "net load" as well.

The 2030 and 2050 targets that have been set for the decarbonisation of the European electricity system will necessitate the integration of vRES on an unprecedented scale. The classic scheduling challenge, in which power systems management takes place under conditions of partial uncertainty, will intensify with vRES integration. Accordingly, there will be an increased need for flexible resources within the system.[9]

2.2 Taxonomy of Operational Flexibility

Both the variability and uncertainty associated with vRES deployment will necessitate more flexibility in power system operation spanning both the supply as well as demand, and including the management of transmission and distribution networks. Operational flexibility may be defined as the ability of the electricity system to balance supply and demand for electricity in real-time, within the limitations of the transmission and distribution system.

The operational flexibility required to meet residual load can be defined according to three related *flexibility metrics* (see also NERC 2010). The first metric is called the *ramp rate*, expressed in MW/h, which represents the rate at which a power plant can increase or decrease output. The second metric, measured in MW, calculates the instantaneous output, or *power*, that matches residual load in real-time. Finally, the third metric, measured in MWh, establishes the average output over time, or *energy*.

These three metrics – ramp rate, power, and energy – define the operational flexibility that can be supplied to a system by means of dispatchable conventional generation, demand response, and storage. Following Ulbig & Andersson (2015), the need for operational flexibility emerges in three distinct domains of power systems management:

→ 1) *Energy Management*
This involves the suppliers' week- to day-ahead forecast and planning activities, followed by intraday planning adjustments and actual production in order to serve aggregate demand in their respective portfolios. In Europe, the energy exchanges, i.e. withdrawals and injections, are typically organised through decentralised, bilateral market-based mechanisms and are resolved on a sub-hourly basis. In this case, the responsibility predominantly resides with the suppliers, also referred to in this context as the balancing responsible parties (BRPs).

→ 2) *Frequency Regulation*
Power systems must be operated within specific frequency ranges if they are to remain stable and reliable. Frequency limits may be exceeded due to real-time imbalances in supply and demand, which may in turn be the product of supplier forecast errors or equipment failures. Frequency regulation therefore involves the real-time balancing of supply and demand. Frequency regulation activities require real-time, i.e. instantaneous and (very) fast-response, adjustments to the power balance. This coordination is generally organised by the transmission system operator (TSO), often via market-based arrangements with energy suppliers and (typically large) consumers.

→ 3) *Congestion Management*
Congestion management, also referred to as power flow management, involves the adjustment of power injections and withdrawals in order to ensure that the network limits are respected. Here, one may distinguish between preventive methods in the day-ahead time frame and corrective methods for real-time adjustment. Congestion management is typically organised by the TSO either through market-based arrangements with energy suppliers and (typically large) consumers or through command-and-control schemes following orders given by the TSO, which

9 The EU 2030 target to draw at least 27 percent of its energy from renewables translates into a share between 45 and 53 percent of renewable electricity in the power sector (see Commission Impact Assessment on a policy framework for climate and energy in the period from 2020-2030). Looking further ahead, the scenarios included in the EU's Energy Roadmap 2050 show a share of wind power and solar PV of up to 72 percent in the electricity mix (EC (2011): Impact Assessment Energy Roadmap 2050, SEC(2011) 1565/2).

typically includes some form of financial compensation. In essence, congestion management is meant to align the dispatch resulting from wholesale market clearing (which does not necessarily reflect network constraints, depending on the structure of the price zones) with the physical realities of the network.

The short-term electricity system scheduling challenge (moving from week- to day-ahead scheduling down to real-time dispatch) involves a minimisation of system operating costs while, at the same time, residual load must be met and system and network constraints be respected. Scheduling is thus a multi-stage task under conditions of uncertainty that proceeds in the following order:

→ First, the week- to day-ahead scheduling costs are minimised, while ensuring sufficient residual load, taking system constraints into account, and maintaining sufficient short-term flexibility for the corrective action expected.
→ Second, the forward schedule must be corrected in a least-cost fashion when moving from a week or day ahead to real-time in light of new information concerning system residual load and system availability, while meeting the other system constraints and maintaining sufficient short-term flexibility to implement the corrective action expected.
→ Third, real-time least-cost corrective actions are to be taken in order to balance the system in real-time and to ensure reliability targets.

As real-time (RT) nears, expected residual load and availability of supply become increasingly certain. At the same time, least-cost longer-term scheduling options to meet residual load will inherently reduce the degrees of freedom in system allocation. For example, the start-up time of conventional thermal power plants requires forward decisions on their commitment, while minimum and maximum production levels of power plants require decisions on the number of units to be committed. Longer-term scheduling may to a certain extent limit the decline in flexibility options in real-time, though at some additional cost. For example, one may commit many power plants in partial load at higher cost rather than fewer units at full output.

A high penetration of vRES does not alter the logic of this multi-stage scheduling process, but it does imply an increasing need for operational flexibility as the forecasting challenge and variability of residual load increase.[10]

2.3 Flexibility Provision in Short-Term Markets

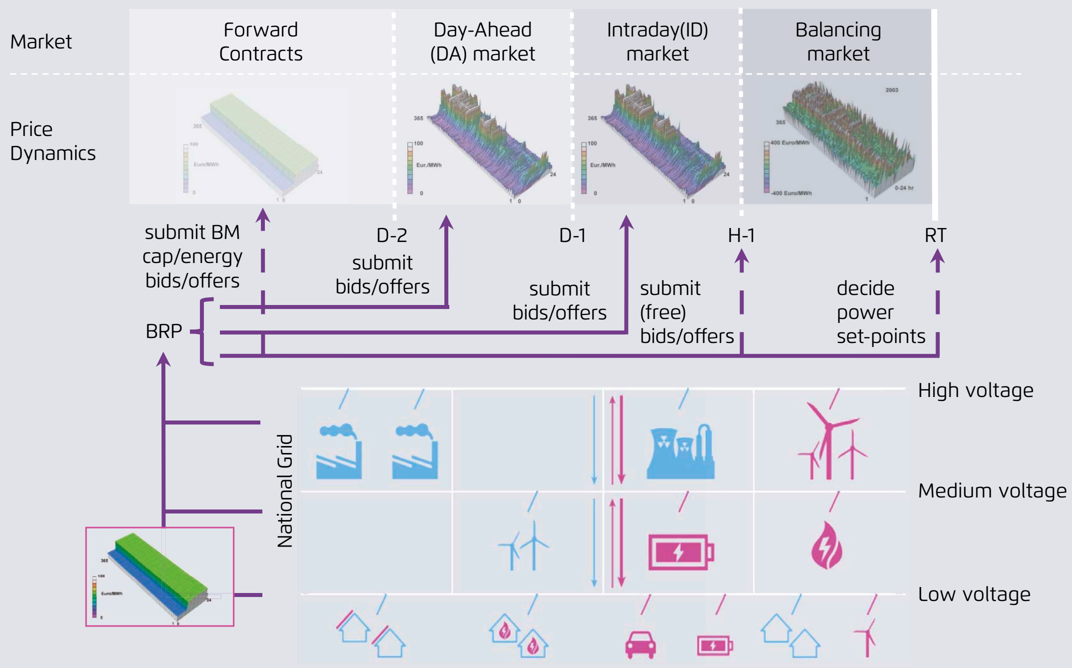
Since the 1990s, when many EU Member States liberalised their electricity markets, the allocation of system resources has been largely coordinated through market mechanisms. Flexibility is typically traded in a sequence of short-term markets for electricity, reflecting the planning stages involved with power systems management. Generally a day-ahead market (DAM), an intraday market (IDM), a balancing market (BM), and, in some instances, a market-based congestion management mechanism (CMM) have been organised. The DAM and IDM provide the market-based dispatch of supply and demand resources, while the BM covers frequency regulation, and, finally, the CMM addresses the management of power flow. In each of these markets, energy is traded, albeit at different time scales and, hence, with different underlying operational requirements.

To enable the efficient supply of flexibility, these market-based mechanisms must be able to provide for the efficient allocation of supply, demand, and storage resources. Therefore, market prices should reflect the value of flexibility (see Figure 1). The overall market design and the structure of short-term markets have a direct influence on price formation. As the allocative efficiency of short-term markets is critical for flexibility provision, we will take a closer look at this aspect of efficiency in the remainder of this report.

Section 3 introduces the relationship between the structure of short-term markets and the underlying operational requirements of the electricity system. This is followed by an

10 RAP (2014): Power Market Operations and System Reliability: A contribution to the market design debate in the Pentalateral Energy Forum. Study on behalf of Agora Energiewende.

Typical organisation of short-term markets for electricity in Europe, with increasing price volatility moving from end-user to supplier (balancing responsible party, or BRP) and moving from day-ahead to real-time. Figure 1



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introduction of several principles that should hold for markets in order to ensure efficient system allocation. The section concludes with examples of (mis)alignment of existing short-term electricity markets in several PLEF countries. Section 4 then offers a more detailed evaluation of current market design features that affect flexibility provision and/or induce (mis)alignment, in accordance with the principles introduced in Section 3. On the basis of this analysis, Section 5 identifies pathways for enhancing the design of short-term electricity markets in order to encourage the effective and efficient deployment and development of national and regional flexibility in PLEF countries.

We include the DAM, IDM, BM, and cross-border CMMs in this analysis. As national CMMs are less commonly based on market principles, these mechanisms have not been considered in the discussion.

3 Market Prices, Flexibility, and Short-Term Market Efficiency

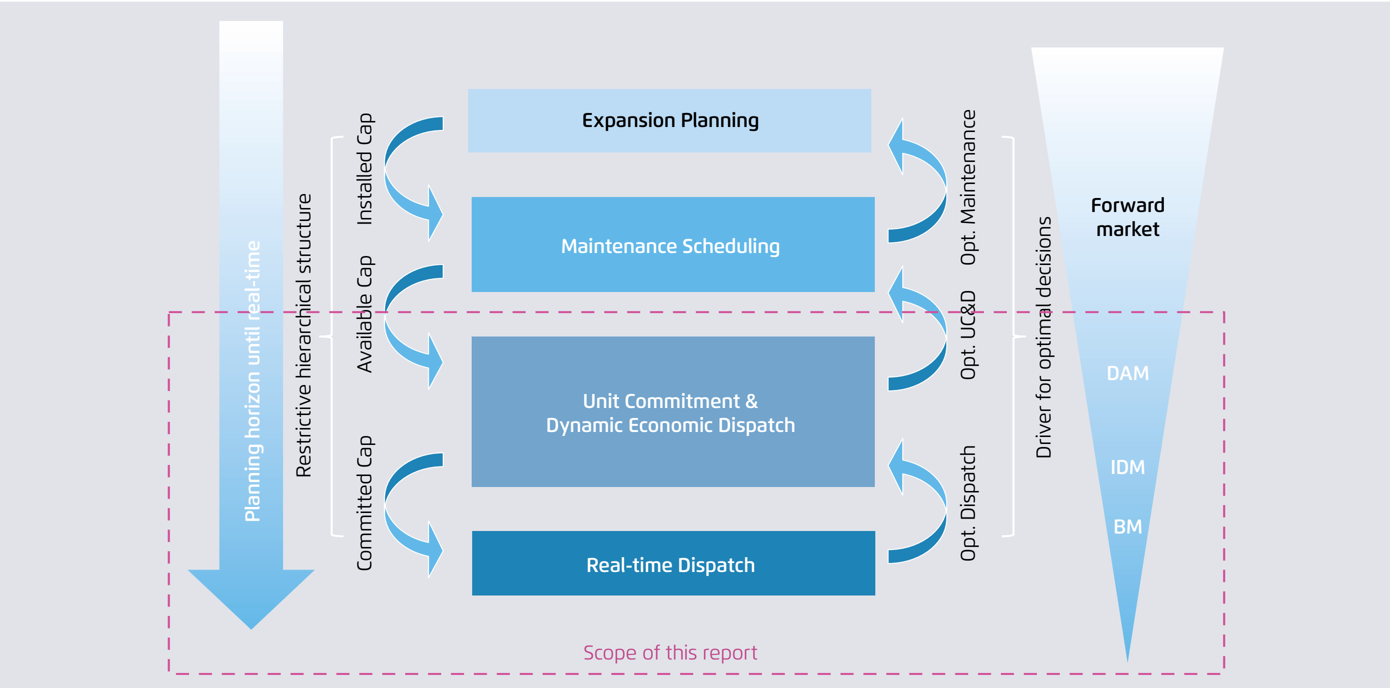
The aim of this section is to develop a sound understanding of pricing in short-term electricity markets as a coordinating mechanism for the supply of flexibility. The section is structured in four subsections. The first subsection (3.1) discusses the role of short-term markets for flexibility supply. The second subsection (3.2) presents three economic principles by which to assess the price dynamics of efficient markets. The third subsection (3.3) evaluates the adherence of four focus markets in the PLEF region (Belgium, Germany, France, and the Netherlands) to these three principles on the basis of empirical data and descriptive statistics. The section closes (3.4) with a discussion of short-term market efficiency in the four focus countries.

3.1 The Role of Short-Term Markets in Supplying Flexibility

Historically, prior to liberalisation, power plant scheduling and flexibility supply were coordinated centrally by means of optimisation algorithms employed to minimise generation costs (i.e. unit commitment, real-time dispatch) (see Figure 2). For instance, "unit commitment" and "dynamic economic dispatch" tools were used to schedule on/off decisions and output levels for the coming day so that expected (residual) demand could be met at minimum cost. The optimisation took into account a reserve target while respecting the constraints of individual power plant units (e.g. min/max output, minimum up-/down-time, ramp-rates, start-up time) and accounting for variable as well as start-up costs. "Real-time dispatch" tools were used to schedule and

Scheduling the supply of flexibility over time

Figure 2



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control output levels in order to meet (expected) real-time demand at minimum cost given the committed fleet, again while respecting power units' constraints and accounting for variable costs. To ensure the coordination of flexibility supply, these optimisation tools were run sequentially and repeatedly (often several times per day), explicitly coordinating both system and power unit constraints in an integral framework.

Since liberalisation, this short-term process and the corresponding flexibility provision have been coordinated by means of market-based mechanisms. The scheduling problem and the different stages of decision-making are reflected in the structure of the market segments that establish dispatch and flexibility supply. The role played in system scheduling by each of the four short-term electricity market segments can be characterised as follows:

→ *Day-ahead markets*
These markets coordinate preliminary least-cost scheduling in the day-ahead time frame in order to meet the expected residual demand while also maintaining sufficient flexibility for the intraday and balancing markets.
→ *Intraday markets*
These markets coordinate adjustments to day-ahead scheduling as more information on real-time drivers (such as demand, plant and line outages, and wind and solar PV production) becomes available.
→ *Reserve markets and balancing markets*
These markets coordinate least-cost adjustment of dispatch by TSOs in real-time, addressing forecast errors and equipment failures, in order to ensure system reliability. Reserve markets typically relate to forward capacity contracting of operational reserves, while the balancing markets[11] involve real-time energy trading.

Reserve and balancing markets are often the market segments associated with the provision of flexibility, since they remunerate it explicitly. For instance, reserve markets remunerate some power units for not producing energy (i.e. keeping production in reserve) and for keeping their flexibility ready for balancing purposes.

Note, however, that all market segments contribute to flexibility provision and allow flexibility providers to earn money. Although DA and ID markets do not trade a product called "flexibility" (only energy products are exchanged in these markets), flexibility provision is nevertheless remunerated in these markets as well. Both markets, for example, remunerate flexibility when there are high variations in residual demand, as some less flexible units will be unable to respond to these variations.

The remuneration of flexibility is also ensured by the relative price movements of different markets. Intraday and balancing prices integrate new information that was unavailable at the DA stage; these prices also reflect the fact that flexible capacity becomes increasingly scarce moving from DA to RT. Given that only flexible capacity can participate in ID and balancing markets (this is because its product length is shorter), relative price differences (DA vs. ID and DA vs. balancing) remunerate flexible capacity.[12] Ultimately, the demand and the supply of flexibility are (implicitly) spread across all short-term market segments; all market segments have a role in coordination and flexibility remuneration.

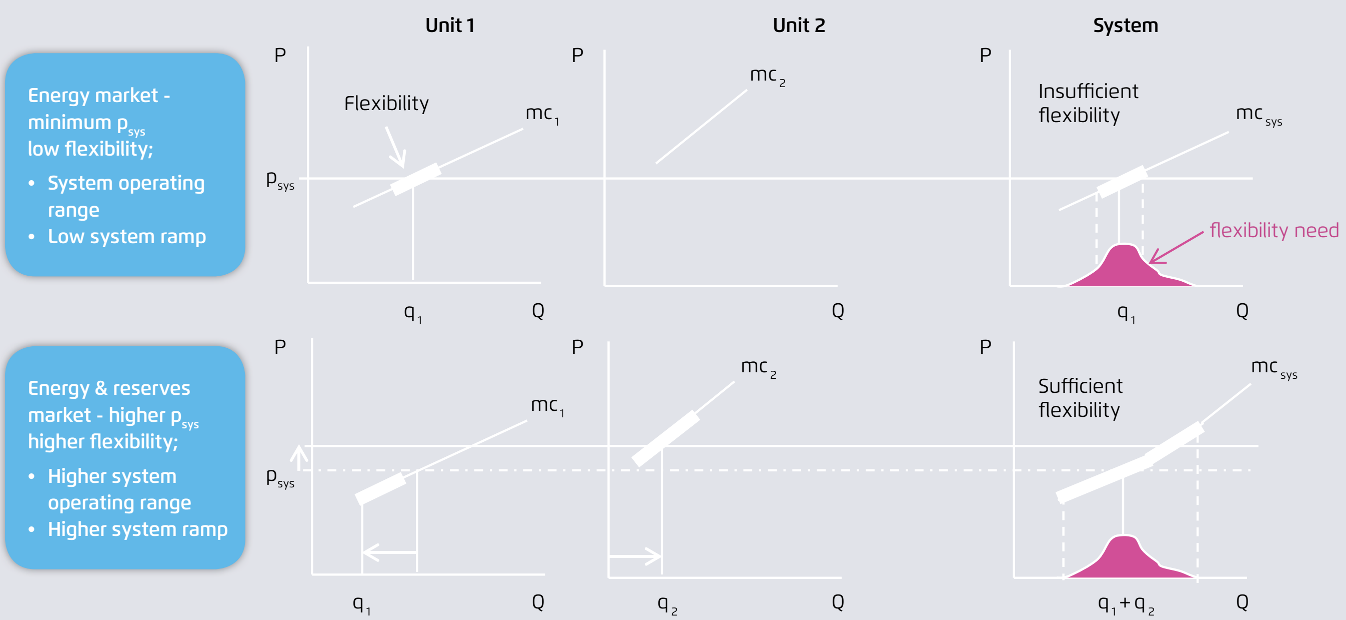
11 Note that the term "balancing market" generally shows a somewhat alternate arrangement from the common conception of market arrangements, as there are typically no demand bids for balancing energy submitted by a broad range of market actors in balancing markets. Rather, the TSO calls upon submitted bids to provide balancing energy (this can come from generation, demand response, or storage units), solely on the basis of its assessment of the balancing requirements. In terms of market design, the balancing market is referred to as a single-sided market, with completely inelastic demand.

12 Other market characteristics can contribute to flexibility remuneration. For instance, the definition of the size of energy products being exchanged (e.g. one hour, half hour, 15 minutes) in each market could be a source of remuneration. If the size of the product is short, flexible capacity can adapt energy scheduling for each period and may benefit from price differences.

Box 1: Example of coordination between the energy market and the reserve market

These market segments and their prices interact to ensure coordination. Figure 3 illustrates the interaction between the energy market (DA) and the reserve market. The upper row of figures shows a hypothetical case without a reserve market where, given the energy price, only Unit 1 is able to provide flexibility. This is shown in the two graphs on the left, which represent the marginal cost curves of Unit 1 and Unit 2. Here, the marginal costs are presented as a function of production. If the DA price P_{sys} on the left is higher than the minimal marginal costs of a unit, the unit is deployed. The least cost solution in this situation is associated with a DA price P_{sys} at such a level that only Unit 1 is deployed. Hence, only Unit 1 can offer spinning reserves, limited by the ramp-rate of the unit (the thickened segment of the marginal cost curves indicated as 'flexibility'). On the right, the system marginal cost curve of the two units is depicted, together with the probability distribution function of system load within the DA time frame (indicated in red). As can be seen, the flexibility offered falls short of addressing the potential load variations in real-time. In this case, the available flexibility is insufficient compared with the flexibility need. The lower row of figures illustrates a situation in which reserve and energy markets work together. When Unit 1 sells its flexibility to the reserve market, its production in the energy market decreases. This allows Unit 2 to enter the energy market. Since Unit 2 has higher marginal cost than Unit 1, the DA price will be higher with a reserve market than without one. Owing to the interaction of the reserve and the DA energy market, Unit 1 and Unit 2 provide sufficient flexibility to meet flexibility need.

Illustration of the coordination between the energy market and the reserve market. The upper series depicts a situation without a reserve market, whereas the situation depicted in the lower series of figures involves both an energy and a reserve market. Figure 3



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3.2 Principles of Price Dynamics in Efficient Markets

The previous section highlighted the role of short-term markets and short-term pricing in the coordination of scheduling efforts from DA to RT and the remuneration of flexibility supply. Market prices are expected to incentivise market participants to optimally schedule resources and to provide the flexibility required.[13] This section presents sound economic principles with which to assess the efficiency of prices in short-term markets.

In theory, the price dynamics of a market depend primarily on the fundamentals (supply and demand). In electricity markets, however, and in short-term markets in particular, price dynamics are highly affected by the market design, i.e. by the specific rules that govern the functioning of these markets (for instance, by the incentives provided to BRPs to balance themselves prior to real-time). Given a set of perfectly designed markets and perfectly competitive market players, efficient prices will induce efficient decentralised scheduling. Practical market design, however, may well diverge from this ideal – depending, for example, on operational requirements and complexity. Also, short-term markets are not typically designed for the sole purpose of efficient system allocation. For example, TSOs may be inclined to design the BM to assure system security, while the costs of balancing are of lesser concern to them.

Unfortunately, there is no unique and comprehensive theory indicating how the efficient prices in a system as complex as the electricity short-term markets should be determined. Consider, for instance, the different product definitions (e.g. energy vs. capacity, size of the settlement period). Considering any of these definitions in isolation would likely result in a different set of efficient prices. Accordingly, a good starting point might be the principle that competitive markets are only efficient when certain boundary conditions are respected (e.g. convexity of cost function, absence of externalities, homogeneity of products, perfect competition, rational expectations, etc.). Some of these conditions are known to apply to electricity markets, though only to a limited extent.

In order to assess price dynamics in existing power markets, we can draw upon a range of economic principles. Based on the economic literature, we have identified three distinct, though not mutually exclusive, theoretical principles:[14]

→ Marginal pricing principle
→ Opportunity cost pricing principle
→ No-arbitrage principle

Even if we relax the conditions that must be fulfilled for competitive markets to be considered efficient, (limited market power, relative homogeneity of products, existence of rational expectations, etc.), the principles listed above should all be satisfied. Non-adherence to these principles in any individual case would result in inefficient allocation from the market mechanism.[15] In the following, these three principles are described in more detail.

3.2.1 Principle of Marginal Pricing

Marginal pricing is a general economic principle that, under certain assumptions, leads to the maximization of social welfare and efficiency.[16] The idea behind the principle is simple. If the price of a good or a service is set at its marginal cost/value for the society as a whole, then the individual market players will act efficiently: they will produce the

13 Hence, pricing efficiency as a driver for allocative and productive efficiency is evaluated, not to be confused with the efficient market hypothesis that was developed in the field of financial economics by E. Fama.

14 The literature reviewed proposes sound general economic principles, focusing on different problems/aspects (see for instance Borggrefe & Neuhoff 2011, Wartsila 2014, Finon 2014, Hirth & Ziegenhagen 2015).

15 Some of these assumptions are not perfectly applicable in a real world and, in these situations, the use of the three theoretical principles should account for this. These issues will be discussed in the market design implementation section (Section 3).

16 Early exploration of this principle is already presented in economic papers dating back to the 1930s. See for example Hotelling (1938): "The optimisation of general welfare corresponds to the sale of everything at marginal cost."

good or service if the internal marginal cost is lower than or equal to the price, and they will consume the good or service if the internal marginal benefit is higher than or equal to the price. If prices follow the marginal pricing principle, then effective coordination between decentralised market participants is ensured, in the sense that social welfare is thereby maximised.

Economic analyses of short-term markets have already applied this principle (see, for instance, Wärtsilä 2014, RAP 2014, Selasinsky 2014, Hirth and Ziegenhagen 2015). As the literature shows, if price dynamics of short-term markets respect this principle, proper signals will be sent to market participants, which in turn will result in efficient scheduling and flexibility supply. Generally speaking, adherence to this principle leads to efficient system allocation that also maximises social welfare. As soon as prices differ from the marginal level, inefficiencies may appear. For instance, if the imbalance price is lower than the marginal cost/value of balancing the system, the market players may not deploy all of their available flexibility resources, and this can result in inefficiencies.

Prices in short-term markets can be assessed on the basis of the marginal pricing principle. Since a lot of information – much of which is not public – would be required to assess the absolute value of prices (with respect to system marginal cost or system marginal value), the marginal pricing principle should be tested indirectly, by studying the relative movements of prices, i.e. price dynamics. In this way, the principle can be tested in several market segments (DA, ID, balancing bid/offer prices, imbalance prices); the internal price dynamics of each segment can be analysed individually or across market segments. Three examples are provided in the following: [17]

- → First, price dynamics can be tested by assessing price movements in the context of how "tight" a given market may be.[18] Assuming that the generation cost function increases with the level of electricity/flexibility production, if prices follow the marginal pricing principle, it is expected that prices will increase when the market is tighter and decrease when the market is well supplied. For instance, in a situation where flexibility provision is highly constrained due to high or low residual demand, one may expect the price of flexibility to increase.
- → Second, price dynamics can be tested by assessing cross-market price movements. For instance, it can be assumed that the supply curve steepens moving from DA to RT, as the availability of sufficiently flexible capacity declines due to the tightening planning horizon as well as increasing commitments. If prices follow the marginal pricing principle, a spread (positive or negative, depending on the system imbalance) between ID prices and DA prices and between BM prices and ID prices should be expected.
- → Third, the marginal pricing principle can be directly tested in balancing markets, as pricing mechanisms differ from market to market. The pricing mechanism applied is a critical determinant of the prices of accepted balancing offers/bids or imbalance prices. For instance, the price of accepted balancing offers/bids depends on whether the pay-as-bid or the pay-as-clear rule is applied. Furthermore, imbalance prices are affected by the use of either an average or a marginal pricing mechanism.

3.2.2 Principle of Opportunity Cost

The opportunity cost associated with the production of certain goods and services is the second theoretical principle we can use to assess price dynamics. Opportunity cost pricing is another general economic principle,[19] and the idea be-

17 The marginal pricing principle can be tested in other ways as well. For instance, in certain market segments, the marginal pricing principle can be tested by comparing prices of compound products (e.g. blocks, hourly products) with products with a lower granularity (30 minute or 15 minute products). Indeed, prices applied to compound products (those that aggregate smaller ones) can deviate from the marginal pricing principle because some degree of "averaging" is applied.

18 Tightness here refers to the condition of the market. It means that supply is constrained in the face of high demand in a physical market, resulting in relatively higher prices. In finance, a tight market refers to liquid markets with frenetic trading activity resulting from tight bid-ask spreads.

19 Economic cost differs from accounting cost in that it includes opportunity cost. For example, if a company owns the building in which it operates, the cost of not renting the building to another enterprise should be included in the economic cost.

hind it is as follows: some resources can be used to produce several goods or services. Efficient pricing for the optimal allocation of these resources needs to include the opportunity cost – i.e. the foregone benefit of not producing an alternative good or service with the same resources. Thus, opportunity cost ought to be included in the price of the respective good or service in order to ensure market coordination and maximisation of social welfare.

The literature shows this principle has been deployed primarily [20] in order to analyse the interaction between reserve and energy markets (see Stoft 2002, Müsgens et al. 2011, NREL 2013). Indeed, flexible capacity can be used (or sold) to provide different services: a) to produce and sell energy (scheduled in DA/ID), or b) to be held in reserve in order to provide flexibility services to the system (i.e. selling reserves to the TSO). As the provision of reserves implies an opportunity cost (not selling energy in the DA/ID markets), this component should be included in the reserves price. Thus, including opportunity cost in the price helps to ensure the efficient coordination (i.e. efficient scheduling) of supply of reserves and energy by market participants.

As an enabler of market coordination, the opportunity cost pricing principle balances (or co-optimises) the cost of anticipatory actions in advance of RT against the cost of corrective action in RT. If market players fail to integrate opportunity cost, inefficiencies will appear. This may be the case when market players bid for reserves without first having all the information they need to assess the opportunity cost (for instance, if the reserves market takes place ahead of short-term energy markets). Similarly, if reservations are made for a long period, market players will have to average their opportunity cost over several delivery periods, which may result in inefficient allocation (Müsgens 2012).

20 This principle has also been used to explain the impact of "non-convex" parts of the function cost of electricity in price behaviour, and in particular to explain negative bids/offers and negative prices (see for instance Nicolosi 2010, De Vos 2015). Indeed, online generators can offer energy in a market at negative prices for a number of hours. Offerings at negative price include the opportunity cost of shutting down the generator and restarting it.

3.2.3 Principle of No-Arbitrage

The third theoretical principle by which to assess price dynamics is based on the no-arbitrage condition. According to this principle, the prices of perfect substitute products should be equal and, thus, systematic arbitrage opportunities should not arise in efficient markets. It is also known as the *law of one price*.

In the electricity market, several products/goods can be seen as at least partially substitutable. For instance, energy designated for the same delivery period but traded at either the DA, ID, or balancing stages can be considered substitutes for one another to some extent. Electricity produced at different locations might also be considered substitute products. For instance, DA/ID/balancing energy produced in zone A is a substitute for DA/ID/balancing energy produced in zone B, provided that sufficient transmission capacity from zone A to zone B is available. If systematic arbitrage opportunities between these markets exist, the market is not perfectly efficient. Arbitrage activity assures coordination between markets trading substitute products in the sense that least-cost alternatives available in different markets are utilised rather than their substitutes.

Arbitrage between different markets helps to coordinate efficient allocation across markets, over time and space alike. Where the no-arbitrage condition does not hold, allocation is not coordinated successfully. The no-arbitrage principle has been applied in the economic literature related to electricity markets, with respect to its temporal (Wärtsilä 2014) as well as its spatial dimensions (Smeers 2004).[21]

The temporal dimension of the no-arbitrage principle

The transmission of information enabled by arbitrage between sequential markets is essential to ensuring an efficient scheduling process under conditions of uncertainty.

21 Note that the no-arbitrage principle can also be tested in cross-product segments (e.g. reserve and energy, energy and transmission capacity). In these cases, the no-arbitrage and the opportunity pricing principles can be used to assess efficiency.

In most commodity markets, price differences between substitutes over the full trading period may be exploited through storage, and this can result in price differences that reflect the costs of storage, of insurance, and of interest on invested funds (collectively known as the *cost of carry*). Given that storage facilities are in short supply in most electricity markets, price differences between substitutes over the full trading period are set by the "expectation value" of the product. For instance, considering that ID products and BM products are substitutes, the price in the IDM should be linked to the expectation of what the price will be in the BM.

A strong correlation between prices in different market segments (e.g. DA and ID, DA and balancing, ID and balancing) will indicate not only the degree of coordination but also the absence of systematic arbitrage, and in this way efficiency is signalled. The opposite result – a weak correlation – will indicate inefficiencies (e.g. if ID prices do not follow the expected value in balancing, arbitrage between these two markets is not efficient).

The spatial dimension of the no-arbitrage principle

For an examination of spatial arbitrage we turn to an example from the ID cross-border CMM. Given the no-arbitrage condition, the relationships between prices of products delivered/produced in different spatial zones (price zones) are supposed to adhere in one of the following two ways:

- → In absence of congestion, the no-arbitrage condition implies price equivalence.
- → In presence of congestion, the no-arbitrage condition implies that the price difference between two zones equals the cost of transmission.[22]

This principle can be tested in various markets segments (DAM, IDM, and BM), by comparing the allocation of interconnection with the corresponding price spread between the zones in question.

3.3 Short-Term Price Dynamics in PLEF Markets

In this section, we evaluate adherence to the discussed principles of efficient pricing by examining descriptive statistics for electricity markets in four PLEF markets (Belgium, Germany, France, and the Netherlands). The three theoretical principles introduced in section 3.2 are used here to assess price dynamics. Simple tests demonstrate whether price dynamics adhere these theoretical principles; when they do not, we discuss the elements of current market design that may be preventing efficient pricing behaviour. This assessment also helps us to determine whether the supply of flexibility is adequately remunerated.

In order to understand the price behaviour in selected markets, Table 1 presents a summary of the key elements in each market design. These market design elements are analysed in detail in section 4.

3.3.1 Marginal Pricing Principle

In this section, we analyse historical data on current short-term markets in the PLEF region in order to assess whether these markets adhere to the marginal pricing principle. Our results show that the marginal pricing principle is generally respected by several market segments (DAM and IDM), thus signalling that current short-term markets are efficiently scheduling and properly remunerating the provisioning of flexibility. In other market segments, however, in particular the balancing market, we find the marginal pricing principle is not perfectly followed. This may be undermining not only the efficiency but also the remuneration of flexibility.

Price dynamics in the DAM

To test whether the marginal pricing principle is adhered to in the DAM, we analyse historical DA prices. If the marginal

22 Transmission prices represent differences in prices between spot energy markets, given transmission constraints. Without constraints, the spot energy price would be the same across each sub-market; arbitrage would equate spot energy prices across locations. If the demand for transmission capacity is higher than available capacity (i.e. congestion exists), the transmission price will be set by the difference between spot energy prices.

Overview of key market design features in the four countries in 2015 Table 1

Market	Type	Feature	Product	Belgium	Germany	France	The Netherlands
Day-ahead Market (organised market)				Market auction with a common price coupling algorithm (EUPHEMIA) Energy products: hourly and blocks Timing: running at noon the day ahead of delivery			
Intraday Market (organised market)				Continuous trading: hourly products	Continuous trading: hourly products + Auction for 15 minutes Products running at 3pm DA of delivery	Continuous trading: hourly products	Continuous trading: hourly products
Balancing Market	Capacity	Reserve provisions		Monthly tender for all FCR/R1 and aFFR/R2, ye-arly tender for mFRR/R3	Weekly auctioning for FCR/R1 and aFFR/R2, daily auction for mFFR/R3	Producer obligations for FCR/R1 and aFFR/R2 Yearly tender for mFFR/R3	Weekly tender for FCR/R1, quarterly and yearly tenders for aFFR/R2 and mFFR/R3
Balancing Market	Energy	Imbalance activation mechanism and prices	aFFR/R2	Pay-as-bid & pro-rata activation	Pay-as-bid & merit order activation	Regulated price & pro-rata activation (outside the BM	Pay-as-cleared & merit order activation
Balancing Market	Energy	Imbalance activation mechanism and prices	mFFR/R3	Pay-as-bid & merit order activation	Pay-as-bid & merit order activation	Pay-as-bid & merit order activation	Pay-as-cleared & merit order activation
Balancing Market	Energy	Imbalance pricing rules		Single/dual pricing rule: marginal balancing energy pricing + incentive component (if NRV>140MW)	Single pricing rule: average pricing (net volume-weighted price)	Dual pricing rule: If imbalance aggravates system imbalance: average pricing (weighted average of accepted offers) + incentive component (k factor) If imbalance reduces system imbalance: DAM price	Hybrid pricing rule: marginal balancing energy price + incentive component

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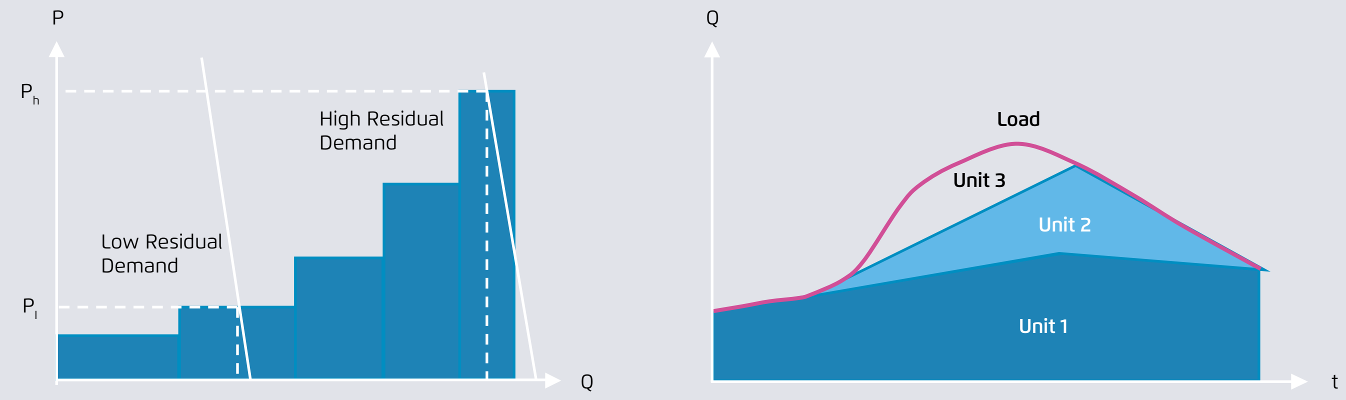
pricing principle is indeed being followed, two assertions can be made (see also Figure 4):

- → DA prices should increase with residual load, since cost of production increases with residual demand. This mechanism is illustrated in the graph on the left in Figure 4: least-cost deployment of production facilities implies that the system marginal cost of production increases with residual load.
- → DA prices should increase with residual load gradients. When the gradient of residual load is high, more expensive flexible units may need to be called upon to cover the residual load swings. If this occurs, the marginal cost of production will increase more than is justified by the increase in residual load (in terms of additional MWh demanded in the market), essentially reflecting the additional system cost of ramp support. This mechanism is illustrated in the graph on the right in Figure 4. Here, Units 1 and 2 have a limited ramp rate and thus cannot follow the high variations in residual load, despite having lower marginal cost than does Unit 3 and despite producing less than their maximum capacity. [23]

23 This dynamic is translated in DAM through the use of blocks of energy. Production units which are not flexible enough use blocks, i.e. they bid energy for multiple delivery periods. The bid is accepted for all the delivery periods or may be rejected, even if the bid is lower than other accepted bids. In case of fast variations of demand, bids with low marginal costs may be rejected in favour of bids with higher marginal costs due to these constraints.

Marginal pricing principle in the DAM. The figure on the left shows that system marginal cost of production increases with residual load. The figure on the right illustrates how a more expensive flexible unit (Unit 3) is called upon to cover residual load (even though Units 1 and 2 have lower marginal costs, but a limited ramp rate) Figure 4



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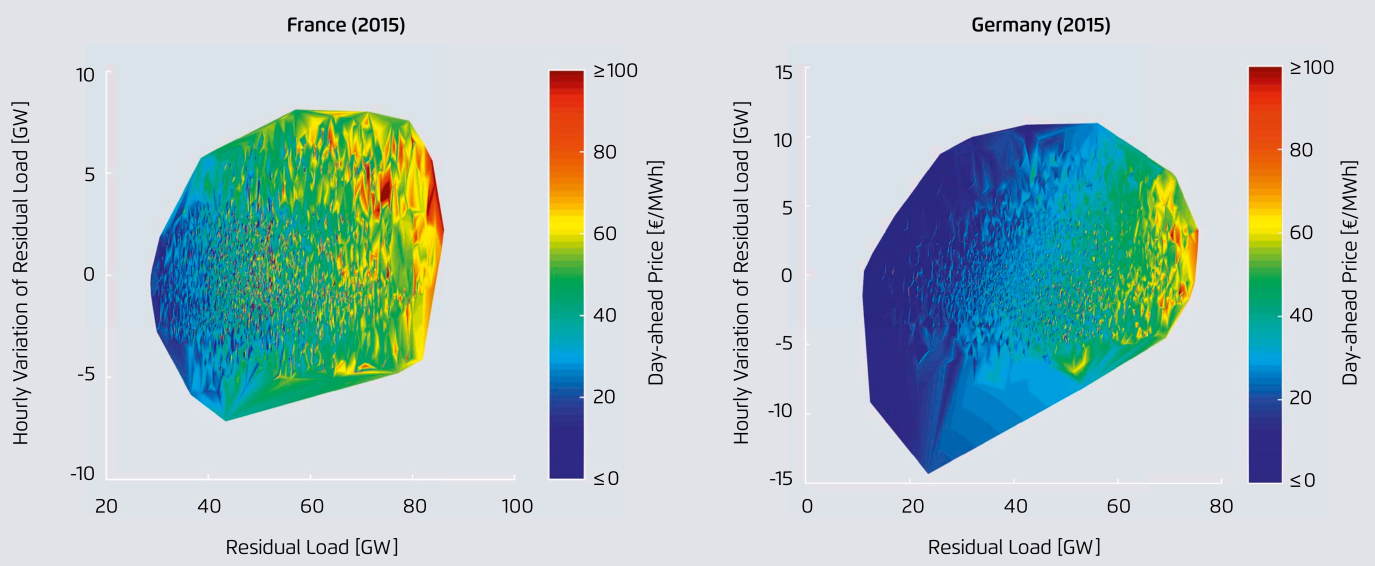
To test the validity of these two assertions, we analyse DA prices as a function of both residual demand and its variations, using data from France and Germany.[24] Figure 5 presents the DAM prices for both countries as a function of residual load (horizontal axis) and hourly residual load change (vertical axis). As can be seen, DAM prices increase with expected residual load, reflecting the increasing cost function of scheduled production (horizontal axis). Prices increase mildly with the hourly change in residual load, reflecting the ramping cost required to meet DA load especially in France (vertical axis). Ultimately, the relevant aspects of flexibility remuneration seem to be in place in the DAM.

24 These graphics have been confirmed by econometrical studies. For the case of Germany, see for instance Pape, Hagemann & Weber (2015).

Illustration of DA price dynamics in France and Germany. The figure shows the day-ahead prices as a function of the hourly variations in residual load (i.e. hourly ramps of the residual load) and the prevailing residual load. Residual load is defined as load minus wind and solar PV generation. Figure 5



CE Delft and Microeconomix based on PX and TSO data[25]

Price dynamics in the IDM

The second test concerns the marginal pricing principle in the IDM. This can be tested by analysing historical IDM data in relative terms compared to DAM data. If the marginal pricing principle is adhered to, we can make the following two assertions (see Figure 6):

→ Depending on updated information on forecasts and availability, ID prices should be higher or lower than DA prices. For instance, in the event of a day-ahead overestimation of renewable production or underestimation of demand, there will be a shortage of power and the ID price will be higher than the DA price. In the opposite situation, the ID price will be lower than the DA price.

→ IDM spreads (defined as the difference between the ID index[26] and the DA price) may be reinforced by availability of flexibility, which typically tightens at high/low residual demand.

To test these two assertions, IDM spreads are plotted against wind power generation forecast errors[27] and residual demand. Figure 7 depicts the results for Germany in 2015, illustrating the correlation between wind forecast error and IDM spreads (see also Selasinsky 2014). The figure on the left represents the IDM spread and the DA wind power generation forecast error for a period of seven days. The IDM spread shows a strong correlation with the forecast error

25 On these graphs, in order to avoid that the price scale is too dispersed, all prices above 100 €/MWh are considered at 100 €/MWh and all prices below 0 €/MWh are considered at 0 €/MWh.

26 For IDM pricing, as the IDM is a continuous market, clearing prices change over the course of the trading period. Hence, an IDM index is used, reflecting the IDM average price.

27 Forecasts errors for wind power generation are computed as the difference between forecasts for wind power generation, estimated DA at 8h00, and the actual generation (published by the German TSOs).

Formation of Price in the IDM

Figure 6

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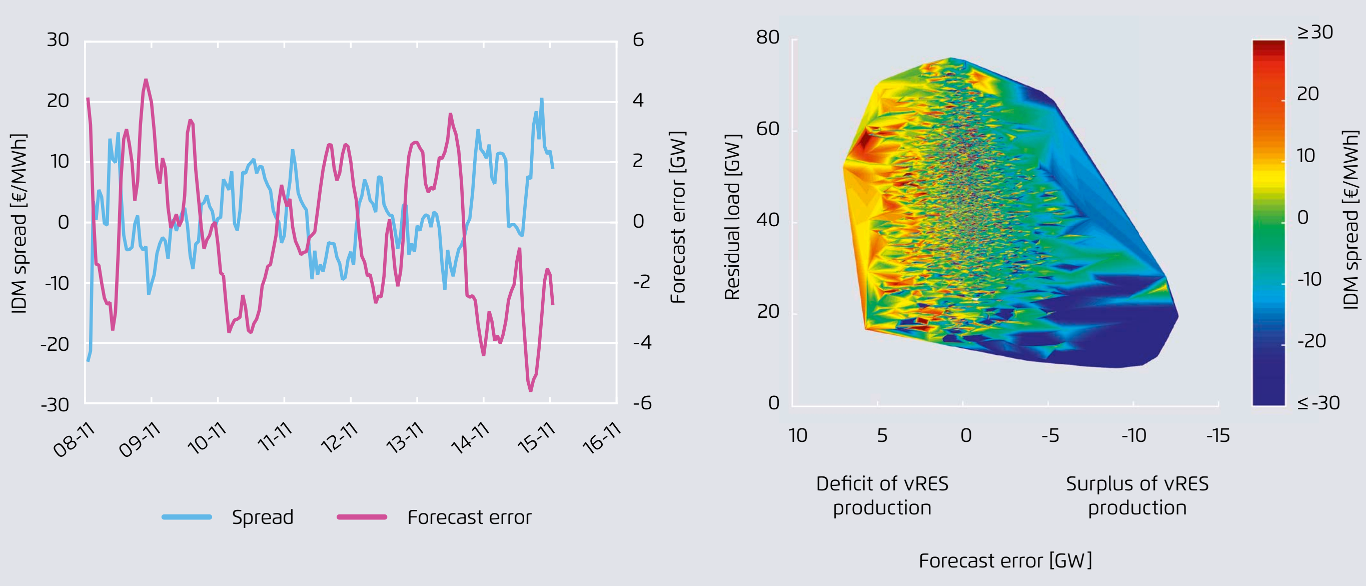
IDM spread (defined as intraday minus day-ahead price) vs DA wind forecast error in Germany in 2015

Figure 7



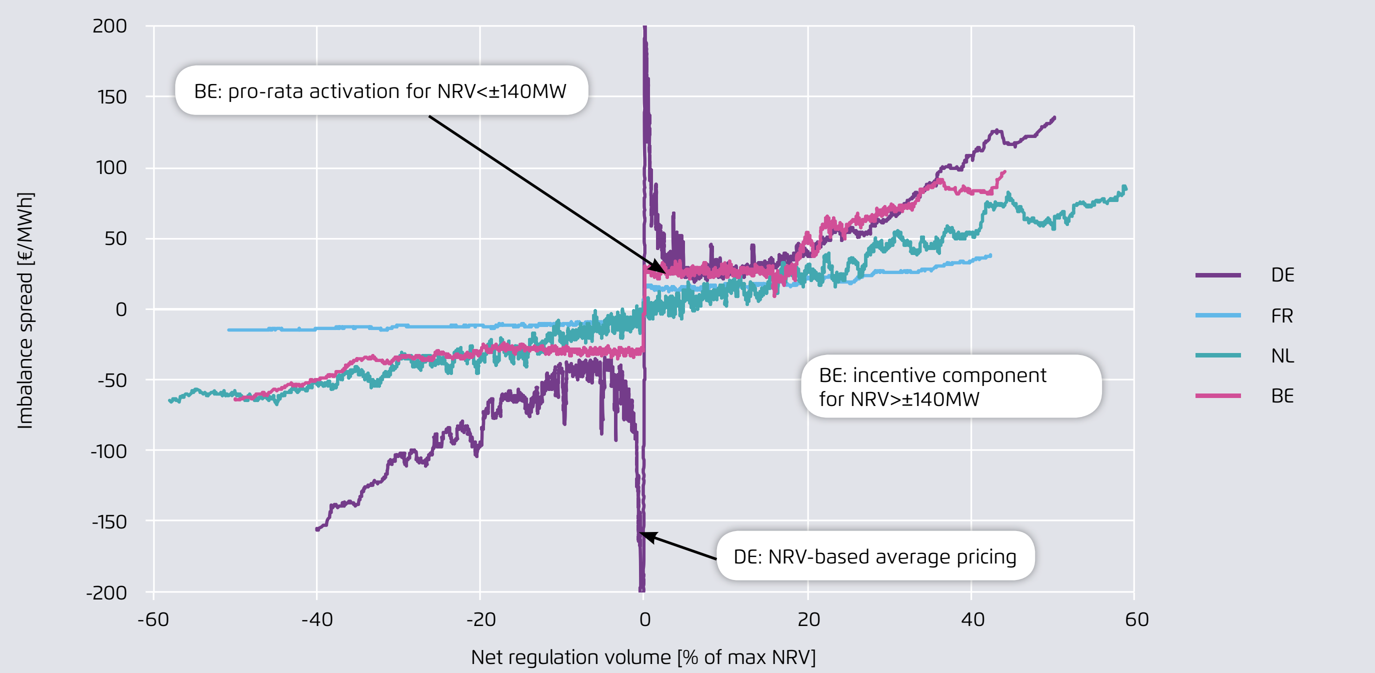
CE Delft and Microeconomix based on PX and TSO data for DA wind power generation, reflecting corrective action in the IDM. Overestimation of DA wind power generation (followed by improved ID forecasts) signals a looming deficit of electrical energy in real-time. Hence, the improved ID forecast that follows upon the initial overestimation induces positive spreads (ID price > DA price). Analogously, DA underestimation of wind power generation induces negative spreads (DA price > ID price). This illustration is a clear indication that prices in the IDM follow the marginal pricing principle and remunerate short-term flexibility to some extent.

The right side of Figure 7 shows that the spread between the IDM index and the DAM becomes more sensitive to forecast error when residual load is relatively low or high. *At low residual load levels*, a limited number of flexible assets are deployed, many of which will run at or near minimum load levels. Hence, an ID upward adjustment in the vRES production forecast induces large downward price differentials as a result of lower availability of downward flexibility, while an ID downward adjustment in the vRES production forecast induces large upward price differentials as a limited number of facilities are likely to be available to offer upward flexibility. *At high residual load levels*, a large number of flexible assets are deployed at or near maximum production levels, so that few can increase production while many can reduce production. Hence, an ID downward adjustment in the vRES production forecast induces large upward price differentials, while an ID upward adjustment in the vRES production forecast induces only mild downward price differentials. In short, lower availability of flexibility induces higher remuneration of flexibility, which can lead to a high remuneration in extreme situations when flexibility is in short supply.

Price dynamics in the BM / imbalance settlement mechanisms

In the balancing energy market (BM), both balancing energy prices and imbalance settlement prices are driven by specific price dynamics. Typically, balancing energy prices are

BM spread (defined as imbalance settlement price minus DAM price) vs. net regulation volume (NRV) in DE, FR, NL, and BE (2015). Figure 8



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Abbreviation: NRV = Net Regulation Volume not always publicly available, whereas imbalance settlement prices generally are. As BRPs pay imbalance costs on the basis of their respective imbalances, these prices give an incentive to BRPs to balance their portfolios in the DAM and IDM. If the marginal pricing principle is respected, we can make two assertions concerning balancing prices:

- → BM activation prices and imbalance settlement prices should be higher than the DA price in the event that the TSO deploys upward regulation; they should be lower in the event of downward regulation, as the cost of remaining flexibility steepens.
- → BM spreads (defined as imbalance price less DAM price) should increase with the volume of activated energy, from zero for small volumes to higher levels for larger volumes.

The mechanisms are the same as those presented for the IDM (see Figure 6), but the price formation may differ, depending on the activation and pricing mechanism of the BM. To test these two assertions, the spread between imbalance settlement prices and DA prices are plotted against the net regulation volume (see also Hirth and Ziegenhagen 2015), i.e. the difference between upward regulation volume and downward regulation volume during a given imbalance settlement period (see Figure 8).[28] The imbalance settlement prices reflect the cost of balancing for the BRPs.

Our analysis verifies the first assertion for each of the four countries: upward regulation induces a positive spread, whereas downward regulation induces a negative spread. Given the imbalance spread that increases with net regulation volume (NRV) in Figure 8, we can conclude that the BM does remunerate flexibility in all four countries. The spread profiles differ widely from country to country, however. Moreover, the second assertion is apparently invalid for France, Belgium, and Germany, where spreads for low volume show non-zero values. Hence, we will have to take a more detailed look at the pricing mechanism for each country.

First of all, the Dutch imbalance price shows full compliance with both assertions, given that the balancing scheme is based on merit order activation, i.e. the balancing energy bids are activated in order of increasing activation price and the price is set through marginal pricing. Hence, the Dutch spread profile shows the expected behaviour, with near-zero imbalance spreads for low NRV levels and steadily increasing spreads for higher NRV levels.

The spread profile for France shows markedly different behaviour. In the first place, we see a notable price step around zero, moving from negative to positive NRV. This price behaviour aligns with the fact that in France an additional penalty component is included in the imbalance settlement price. Furthermore, the spread profile for France shows relatively low price sensitivity to increasing NRV volumes. This point can be explained by the average pricing which is applied for imbalance settlement pricing in France (imbalance settlement prices are based on the average cost of the gross regulation volume). As average prices increase more moderately with NRV than marginal prices, one might expect the French imbalance settlement prices to remain relatively flat in comparison to the Dutch imbalance settlement prices.[29] Furthermore, remuneration in France is based on a pay-as-bid mechanism rather than on uniform pricing. Low-cost bidders may then be expected to bid up to the expected price level of the highest bid (i.e. the expected uniform price that would result if it were applied) in an attempt to capture inframarginal rents, which would result in prices above marginal cost for low NRV levels.

The Belgian prices show a comparably flat price profile between ±15 percent of max NRV, corresponding to an NRV of some ±140 MW, while we also see prices increasing more steeply for larger NRV volumes. In Belgium, the imbalance settlement price is set by the marginal balancing energy

28 The imbalance spread values were sorted by increasing NRV, followed by calculation of a moving average over 180 imbalance settlement periods (ISPs) in order to visualise the NRV-dependent structure of the data set.

29 Of course, differences between Dutch and French imbalance settlement prices may well result from differences in the cost structure of the assets deployed in the two countries.

price, defined here as the highest price of the deployed reserve categories (R2/aFFR, R3/mFFR, but also IGCC netting and non-preselected R2/aFFR bids). The ±140 MW range corresponds to the contracted amount of secondary reserve (R2/aFFR) capacity, a reserve category that is activated on a pro-rata basis. Parallel activation is applied, and each additional MW is produced proportionally by all bids that were preselected day-ahead. Thus, the highest bid activated sets the price for the full range of ±140 MW R2/aFFR deployment. Outside this range an additional penalty component applies, proportional to the mean squared system imbalance over the preceding eight imbalance settlement periods (ISPs).[30]

German imbalance spreads show very high levels for near-zero volumes, while spreads decrease steeply for moderate NRV levels up to some 5 percent of max NRV and increase steadily for NRV levels beyond this. In the case of Germany, the imbalance settlement price is based on the average price of activated balancing energy. However, net regulation volume is applied for price averaging rather than gross regulation volume (GRV). In the event the NRV is near zero, while GRV and its activation price are not, the average price can attain very high price levels. For higher NRV levels, the impact declines significantly as NRV and GRV converge and we can see a moderate increase in the imbalance spreads. This increase may involve a "risk premium" or "mark-up" relating to the German week-ahead gate closure and the risks and/or costs relating to the resulting availability requirements.

To sum up, the imbalance spreads are severely affected by the imbalance settlement pricing mechanisms (NRV- or GRV-based average pricing vs. marginal pricing) and by the activation mechanisms for balancing energy bids (pro-rata vs. merit order activation) that are applied in each case. The Dutch BM shows a market design that aligns with the marginal pricing principle, while the other BMs do not adhere to this principle due to key design aspects.

3.3.2 Opportunity Cost Pricing Principle

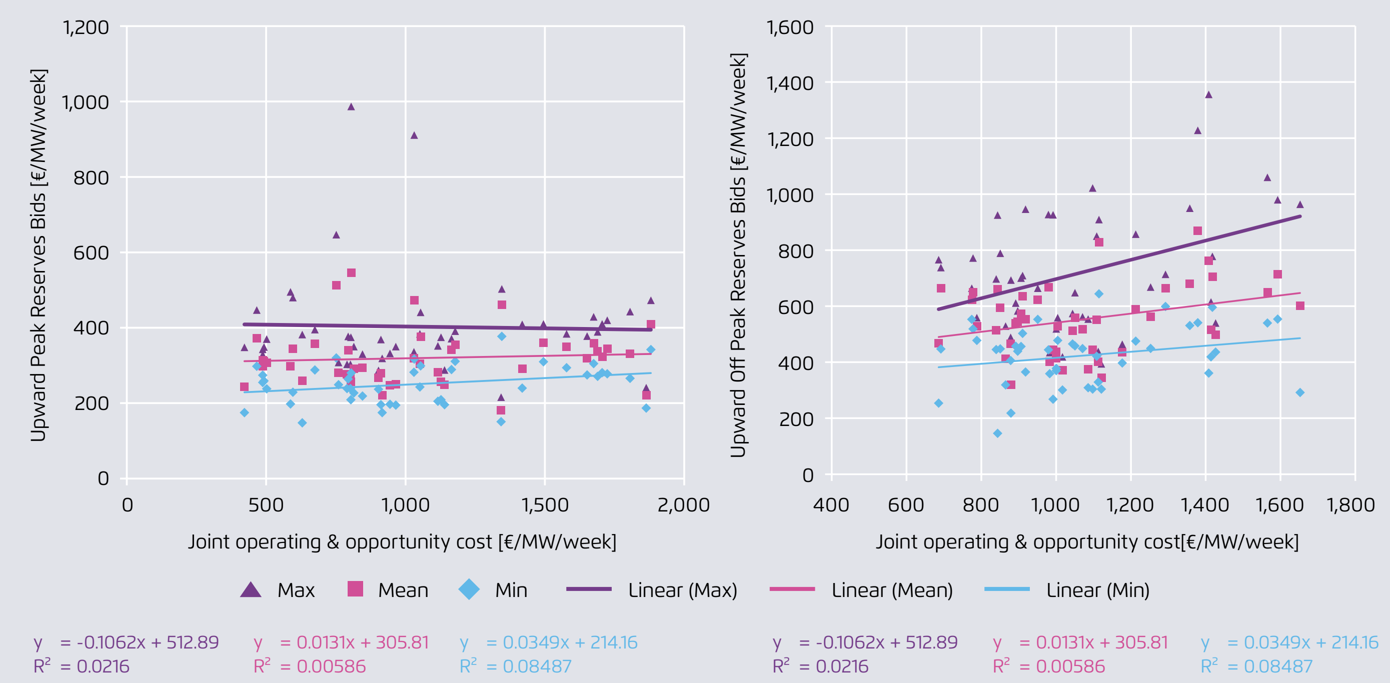
The opportunity cost pricing principle in short-term electricity markets implies that price dynamics in one market segment should reflect the foregone benefit of sales in another market segment. An example is provided by the sales of capacity in the reserves market and the resulting missed opportunities in the DAM. Capacity in the reserves market is typically procured well ahead of DAM clearing. Once accepted in the reserve market, a capacity has to comply with some constraints that reduce its profits, as compared to an alternative situation where this capacity would not be reserved. First of all, the sale of capacity in the reserves market implies that this capacity can no longer be offered in the DAM.[31] This can result in a foregone profit if the marginal cost of the reserved unit is lower than the DAM price (were the capacity *not* reserved, its entire output could have been sold in the DAM). Secondly, because of the required response time involved with the provisioning of reserves (in particular for secondary reserves), the facilities providing this type of reserves will be required to have the reserved capacity available as *spinning reserves*. In other words, these facilities will have to be up and running (at minimum load or higher production levels) during the entire period that they are committed as reserves, no matter what the DAM prices may be. This may imply an additional cost in the event that DAM prices fall below the marginal cost of production – an additional cost that would not be incurred if this capacity did not constitute part of the reserves. Accordingly, one should expect an efficient price for capacity in the reserves market to reflect the relevant opportunity costs, namely the foregone profit that might have been made in the DAM plus potentially any loss incurred as a result of minimum load requirements.

In Germany, reserved capacity for aFRR/R2 is procured as a weekly product on a week-ahead basis. Separate products for the provision of negative (downward) and positive (upward) control reserves are procured, for the supply of reserves both at peak hours (8h00-20h00, business days) and off-peak hours (all other hours). Assuming a significant

30 The imbalance settlement period is set to 15 minutes in Belgium.

31 Of course this also applies for the IDM, but volumes in this market segment are typically much lower.

BM reserve capacity pricing against opportunity costs for Germany 2015 — Figure 9



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proportion of supply is offered by either coal-fired or mid-merit gas-fired facilities (often these are Combined Cycle Gas Turbines [CCGTs]), one may compare prices for reserved capacity against the additional operating cost and foregone profit incurred by these sales. The additional operating costs are the costs associated with operations at minimum stable load in the DAM when the marginal costs are above DAM prices, while the foregone benefits are based on the non-production in the DAM when prices are above DAM prices (see Müsgens et. al. 2011, among others). Operating costs are then based on minimum load levels, thermal efficiency, and the size of the capacity bid-in to the reserves market. Figure 9 presents minimum, mean and maximum accepted capacity reserves bid prices for provision of upward balancing energy with a two week lag against expected opportunity cost for a coal-fired facility. Both the accepted bids for capacity reserves during peak hours (on the left) and off-peak hours (on the right) are presented. A capacity of 600 MW, minimum stable load of 300 MW, and a thermal efficiency of 35 percent are assumed, offering its full 270 MW potential of capacity reserves limited by a 3 percent of nameplate capacity per minute ramp rate.

In both product categories, prices are typically well below the computed opportunity costs. Such differentials could be caused, for example, by incorporation of (part of) the profit that can be made on the balancing market by the contracted reserve in its capacity bid. Furthermore, it appears noteworthy that the off-peak products show a low correlation with the opportunity cost. In the case of peak products, only the minimum bids show a low correlation with the opportunity cost. In both instances, however, the estimated costs of supplying reserves are relatively volatile, such that the correlation is not significant. Because of uncertainties surrounding the exercise, the opportunity cost pricing principle is not conclusive in this case.

3.3.3 No-Arbitrage Principle

The aim of this section is to assess whether PLEF markets allow for efficient arbitrage, both spatially and temporally. In the following, we analyse the relationship, or correlation, between the prices of two products that may be considered at least partial substitutes for one another. Our results show that the corresponding *no-arbitrage principle* is largely adhered to. Nevertheless, poor or unavailable information as well as market design constraints may prevent market players from achieving efficient arbitrage.

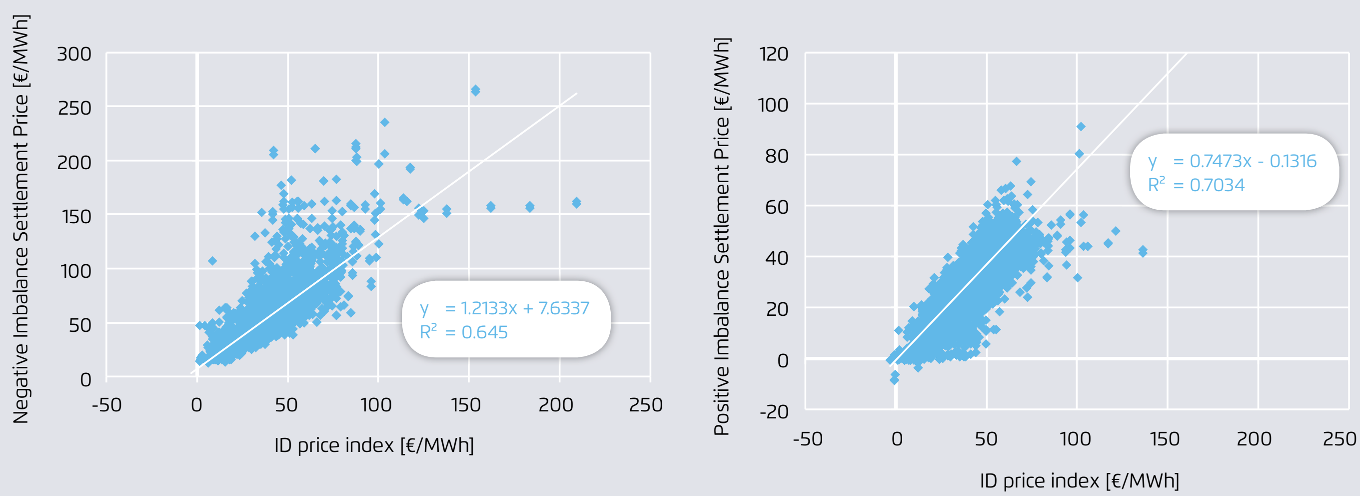
Temporal arbitrage between the IDM and the BM

The first tests we perform are on temporal arbitrage between markets. To do so, we analyse the relation between ID prices and imbalance settlement prices. The latter are understood as reflecting the cost of balancing and incentives to market players to balance themselves prior to real-time. These two products are considered partial substitutes, since a BRP can choose to balance its portfolio on the IDM or to wait for real-time and allow the TSO to balance the system.[32]

This arbitrage can be performed efficiently only if the BRPs have reliable information about the expected imbalance settlement price that they can integrate into their decision at the IDM stage. In this case, a strong correlation between imbalance settlement prices and IDM prices is expected.

32 In many countries, the BRP is contractually obligated to balance in every ISP, as is the case in Germany (with an additional clause in the grid access regulation that BRPs have to ensure balancing), Belgium (though the obligation was replaced with the requirement that the physical capacity for self-balancing be available in 2014), and The Netherlands (where the contractual obligation is to act according to the programme). With that, deliberate disregard of emergent portfolio imbalances is legally disputable. However, it should be noted that there is a limited risk of enforcement, as it will be complicated to prove intentional imbalance. In addition, in some countries, like the Netherlands, the contractual obligation to balance contradicts the regulatory facilitation of passive contributions.

Arbitrage between IDM and BM (France 2015) — Figure 10



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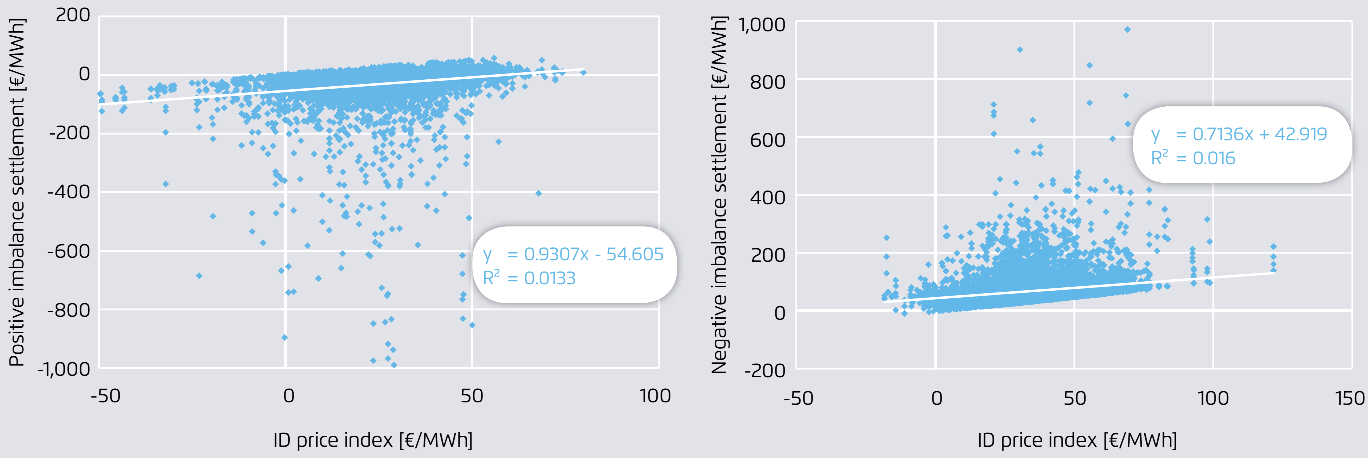
Arbitrage between IDM and BM (Germany 2015)[33]

Figure 11



CE Delft and Microeconomix based on PX and TSO information

Indeed, if imbalance settlement prices are expected to rise, market players are incentivised to balance in advance of real-time, which in turn increases demand for flexibility and associated prices on the IDM. If the expected value of imbalance settlement prices is low, market players may wait until real-time and let the TSO balance the system.

Figure 10 and Figure 11 show a high level of correlation between the IDM and BM in France and a low level of correlation in Germany. This suggests that arbitrage in Germany is inefficient, and that BRPs may be unable to make efficient decisions concerning the choice between IDM and BM.

This situation may be explained by the fact that imbalance prices in Germany are published one month after real-time, whereas they are published only an hour after real-time in France. This delay in Germany implies that market actors lack information about the current situation in the system. Moreover, in Germany, imbalance prices are very volatile, and do not necessarily reflect the tightness of the market, given that average pricing here is based on net regulation volume, as discussed above.[34]

Spatial arbitrage on the IDM

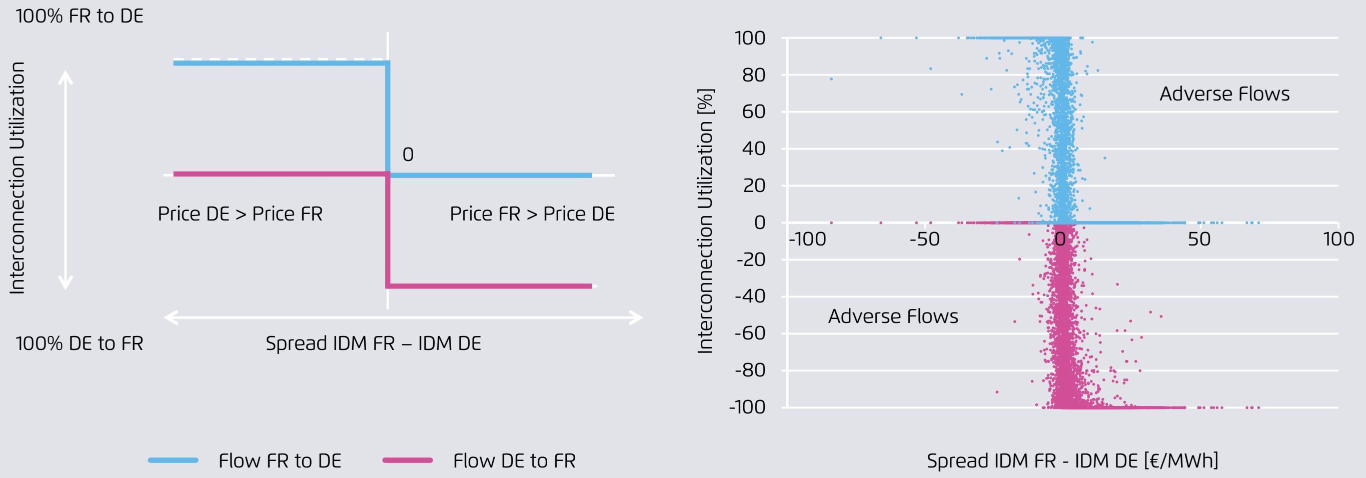
In this subsection, we evaluate the spatial dimension of arbitrage with a view to the logical consistency maintained between cross-border flows and the price spread, i.e. the cross-border price differential for the product traded. As an illustrative example, we compare the ID cross-border

33 Only data for NRV volumes higher than 5 percent of the maximum value were included, to exclude the price effect of NRV-based averaging.

34 Note that other reasons can potentially explain a low correlation. For instance, the granularity of products traded in the different market segments could be different (60 versus 15 minutes). ID prices used to assess correlation correspond to a weighted average of many different products (e.g. hourly products traded at different time of the day). Some of these products may be exchanged well before real-time.

German-French IDM spreads vs. cross-border flows[37]

Figure 12



CE Delft and Microeconomix based on PX and TSO information

capacity with the IDM cross-border price spread between France and Germany. In this case, there are two mechanisms in place for ID cross-border capacity allocation, generally referred to as *explicit allocation and implicit allocation*. Explicit allocation requires capacity requests to be made explicitly via a capacity management module, whereas the implicit allocation of cross-border capacity implies an instantaneous allocation of cross-border interconnector capacity when a cross-border intraday energy trade is cleared. The explicit mechanism utilises a common capacity platform[35] that is operated by the respective TSOs, while the implicit cross-border trading scheme[36] is operated by EPEX Spot. Available capacity is offered free of charge under both mechanisms, which is likely to contribute to inefficient allocation.

In case of efficient arbitrage, one should expect:

- → Partial cross-border capacity nomination if the price spread is null, and full cross-border capacity nomination if a non-zero cross-border price spread persists.
- → Nominated cross-border flows from the country with the lower price to that with the higher.

These two expectations are represented on the left in Figure 12. The graphic on the right of Figure 12 shows the ID utilisation of the interconnection between France and Germany in 2014. Divergences from the expected pattern indicate that arbitrage opportunities remained unexploited. In many instances, the interconnection was not fully used, though the spread is non-zero. Worse yet, capacity was occasionally allocated to flows from the country with the higher price to the country with the lower one. This means that

35 See https://www.intraday-capacity.com.

36 The mechanism is known as the Flexible Intraday Trading Scheme (or FITS), enabling implicit cross-border trading between France, Germany, Austria, and Switzerland.

37 For this comparison 2014 data were used, since in 2015 the cross-border capacity data are no longer readily available now that flow-based market coupling has been introduced.

flexibility was not often provided at least-cost, implying a less than optimal allocation in terms of general social welfare.

These results for the French-German border may be explained by the explicit allocation of cross-border capacity, in conjunction with implicit allocation. Since the energy and capacity products are obtained separately in case of explicit allocation, this could produce inefficient results such as adverse flows (power flowing from the high-price area to the low-price area). Other potential causes of this inefficient arbitrage may be found in the difficulties of designing an efficient market coupling system for continuous trading as well as in the lack of a centralised means of ID cross-border pricing.

3.4 Conclusions

In this section, three principles for the efficient remuneration of flexibility were derived from general economic theory and the literature related to power system economics: the principle of marginal pricing, the principle of opportunity cost pricing, and the no-arbitrage principle. Testing the short-term markets in four PLEF countries for adherence to these principles suggests that both the DAM and the IDM comply well with these principles and show clear signs of efficient flexibility remuneration. Remuneration on the DAM, for example, shows mild increases in remuneration if flexibility is required to serve hourly load. The IDM shows strong correlations with flexibility demand to correct for adjustments in the vRES load forecasts; and, where residual forecasts suggest tight flexibility conditions at either high or low system load levels, higher prices incentivise the deployment of additional flexibility and correspondingly remunerate this additional flexibility through the IDM.

The balancing markets, on the other hand, typically fail to adhere to the principles enumerated, and this induces inefficiencies in flexibility remuneration and system allocation. The reasons for this are to be found in the balancing market designs specific to each country (pay-as-bid remuneration, pro-rata balancing deployment, regulated tariffs, delays in publication of imbalance prices).

Since the balancing market serves as the market of last resort for balancing supply and demand at all times, inefficiencies in this market should be expected to spill over into market segments prior to the balancing market. This suggests that a high priority should be assigned to adjusting BM specifications in the PLEF. To illustrate, we briefly summarise the German imbalance settlement system. Like the Belgian and the French system, average pricing is applied here, rather than marginal pricing. However, in the German scheme, averaging is based on net regulation volume, which translates to very high imbalance settlement prices for low imbalances, which then results in increasing volatility when system imbalances decline. In addition, publication of imbalance settlement prices in Germany occurs one month after realisation, so that imbalance prices are difficult to estimate and imbalance price risk will be high. Under these conditions, effective hedging strategies in the IDM are unlikely to result in an efficient system response to imbalances. This is confirmed by the poor correlation between IDM prices and BM prices in Germany.

Of course, our assessment, which seeks to identify inefficiencies in short-term pricing in the selected countries, is generic in nature. In order to identify adjustments to market design that could potentially address these inefficiencies, a more extensive assessment is required. Thus, in the following section, we provide a more detailed appraisal of market design features in PLEF countries.

4 Key Market Design Parameters

In the previous section, we presented an empirical evaluation of pricing efficiency in selected PLEF countries (France, Germany, Belgium, and the Netherlands). We introduced three principles of efficient pricing (marginal pricing, opportunity pricing, arbitrage-free pricing) and then reviewed adherence to these principles in the selected markets.

For markets to achieve efficient allocation and while also providing the socially optimal amount of electricity at least total cost, these three principles of efficient pricing should hold. These pricing principles and perspectives for efficient allocation are intrinsically linked with market design.

Specifically, the market design should establish a series of boundary conditions that not only enable efficient pricing but also yield a competitive equilibrium within and among markets in order to achieve efficient allocation. In this section we seek to identify key design elements in short-term electricity markets that would enable the institution of efficient pricing mechanisms, leading to efficient system allocation, and, ultimately, facilitating the supply of flexibility. We will assess three market design aspects:

→ 1. **Market access:** To what extent can power markets be accessed by different market actors and/or by different demand or supply side technologies?
→ 2. **Market completeness:** Can electricity be traded along a "continuous" set of markets – from "the far future" to "real-time"?
→ 3. **Market pricing:** How are clearing prices formed and to what extent is pricing constrained by market rules?

These dimensions do not only span the market design of the individual PLEF countries but also cross-border market integration. As such, this assessment should also be taken as an integral view on ongoing efforts to enhance market integration in the European framework, with emphasis on the challenges posed by decarbonisation and the related call for flexibility provision.

In the following, the market design parameters for the PLEF region[38] will be assessed along these three dimensions. Finally, pathways for robust market design and enhanced integration of the PLEF region will be discussed.

4.1 Market Access

In order to maximise allocative efficiency and the supply of flexibility, access to the market should be maximised. However, access to short-term electricity markets may be differentially limited by the market features and arrangements for different market actors and/or supply/demand side technologies in question. There are several conditions that may limit access:

→ **Programme requirements and balancing responsibility:** These requirements for market participation are designed to ensure safe and secure system operations.
→ **Trading arrangements:** In order to obtain access in short-term markets, actors must fulfil additional requirements, including technical and operational prerequisites or compliance with information, measurement, verification, and communication protocols.
→ **Product specifications:** Minimum bid requirements may also limit market access depending on the product being traded. Minimum bid requirements may apply to a number of parameters, including volume, availability, duration, activation time, and ramp rates.

These regulations are not necessarily technology neutral and may result in explicit or implicit exclusion of certain technologies or actors. For instance, the existing regulatory regime may exclude demand-side response participation; certain categories of market participants, including con-

38 The Austrian, Belgian, Dutch, French, German, and Swiss arrangements will be compared here. Luxembourg is part of the German control block, hence there are no separate market arrangements.

sumers, renewables, and storage; or cross-border market access. We will discuss this exclusion in more detail below.

4.1.1 Programme requirements and balancing responsibility

Since electricity cannot be stored in the grid, electricity in-feed and off-take from production assets, storage facilities, and loads needs to be balanced and this balance must be maintained within very narrow tolerances at all times for safe and secure system operations. Balance responsibility refers to arrangements made between producers and consumers through BRPs in order that supply is balanced against consumption. These arrangements may include incentives for both players to minimise their respective imbalances. BRPs are required to develop programmes (sometimes called "schedules") designed to balance both the in-feed and off-take of electricity, typically one day in advance of realisation or less. If actual in-feeds or off-takes diverge from the programme or schedule, the resulting imbalance (calculated as the difference between actual in-feed/off-take and the programmed quantity) is managed materially by the TSO via the reserves and balancing markets and financially via the imbalance settlement mechanism. The latter incentivises BRPs to minimise imbalances by imposing imbalance payments. Hence, the programme requirements and balancing responsibility contribute to secure system operations. Every participant in the system is either balance responsible or requires representation by a BRP. Balancing responsibility for households and for small and medium enterprises (SMEs) is typically legally imposed on their energy supplier, who in turn can outsource its balance responsibility to a BRP.

The market design arrangements involved with balance responsibility were originally developed in the context of centralised production and distribution of energy, which means that these arrangements can account for decentralised production and **demand side market access** only to a limited extend. For instance, households and SMEs have been historically excluded to large extent from real-time metering, and are thus not positioned to take part in any imbalance-minimising arrangements. With the new smart meter program set for roll-out by 2020, formerly excluded participants may acquire a more active role in balancing responsibility, but this will only be the case if **aggregate demand side market participation** is allowed. In most short-term electricity markets in the PLEF region, both direct demand side market participation (typically relating to

Demand side market access in the reserve markets (primary reserves (R1); secondary reserves (R2); tertiary reserves (R3)) in the PLEF countries in 2015. Note that demand side market access in the day-ahead and intraday markets is allowed across the PLEF region. Table 2

	Load				Aggregate load			
	R1	R2	R3	Special DR products	R1	R2	R3	Special DR products
Austria	yes	yes	yes	n.a.	yes	yes	yes	n.a.
Belgium	partial (R1 Load share max. 33%)	no	partial 10 percent (R3 DP) + 40% (R3 ICH)	n.a.	partial (R1 Load share max. 33%)	no	partial 10 percent (R3 DP) + 40% (R3 ICH)	n.a.
France	yes	yes	yes	yes	yes	yes	yes	yes
Germany	yes	yes	yes	yes	yes	yes	yes	yes
The Netherlands	yes	yes	yes	n.a.	yes	yes	yes	n.a.
Switzerland	yes	yes	yes	n.a.	yes	yes	yes	n.a.

CE Delft and Microeconomix based on TSO information and SEDC (2015).
Abbreviations: R1 Load = R1 interruptible load (FCR), R3 DP (Dynamic Profile) = interruptible load – max 2h interruptions (mFRR), R3 ICH = Interruptible load – 4h, 8h or 12h interruptions (mFRR), DR = Demand Response.

Regulatory arrangements facilitating independent aggregation for the different short-term electricity markets in the PLEF countries in 2015. Table 3

	DAM	IDM	R1	R2	R3	Special (DR) products
Austria	no	no	no	no	no	n.a.
Belgium[39]	no	no	no	no	no	n.a.
France	yes	yes	yes	yes	yes	yes
Germany	no	no	no	no	yes	no
The Netherlands	no	no	no	no	no	n.a.
Switzerland	no	no	yes	yes	yes	n.a.

CE Delft and Microeconomix based on TSO information and SEDC (2015).

industrial electricity consumption) and aggregate demand side market participation are allowed. Only the reserve markets in Belgium make explicit exclusions in this respect (see Table 2).

A critical market design element involves the arrangements for independent aggregation. Table 3 gives an overview of the current situation with this regard in the PLEF countries. Aggregation may be defined as the activity of amassing and assembling supply and/or demand resources, an activity classically performed by energy utility companies. However, as the electricity sector in the Central Western European (CWE) region was liberalised, the field of aggregation itself has been expanding. Now, decentralised resources are also aggregated, and there have emerged additional service offerings related to aggregation in various electricity markets.

The expansion of service offerings in the area of demand response is generally considered problematic. These offerings affect energy supply in the sense that, if the market rules are not appropriate, the suppliers of demand response can appear to be selling electrical energy without buying it before. Indeed, since the suppliers of demand response do not produce energy themselves, they must first buy electrical energy, to own it and then be allowed to sell it back. Furthermore, demand side participation leaves the energy supplier/BRP with possible programme mismatches and thus also with open positions in the imbalance settlement mechanism (see for example SGTF 2015, SEDC 2015, and Eurelectric 2014). Independent aggregation services that seek to target demand response therefore will have to be coordinated with the supply activities of the supplier. This coordination would involve contractual arrangements to establish the allocation of costs and benefits. However, such arrangements are typically not in the interest of the supplier/BRP. It has therefore been remarked that aggregation services should be allowed without the explicit consent of the supplier, so long as compensation for the impact on the supplier's balancing area is assured.

In recent years, explicit regulatory arrangements for independent aggregation have been established in France and Switzerland. In these two countries, independent aggregators are allowed to contract consumers without the supplier/BRP's agreement. The BRP is initially compensated for the aggregator's demand response activation at a centrally established price, while any resulting imbalances are accounted for retroactively. In some PLEF countries (e.g. Austria and Germany[40]), bilateral arrangements are made between aggregators and suppliers/BRPs. Non-binding contract templates can enable such bilateral arrangements.

39 The subject is currently under review in Belgium.

40 The grid access regulation contains a paragraph to enable independent aggregation for tertiary reserves. An extension to secondary reserves shall be implemented in 2016.

4.1.2 Trading arrangements

In each short-term market segment, market participation may involve a series of additional trading requirements. Notably, to enter into the reserve and balancing markets as a Balancing Service Provider (BSP), a series of technical and operational prerequisites must be met. To this end, several TSOs in the PLEF countries established prequalification procedures for entry into the reserve and balancing markets. These procedures, however, can be restrictive, especially for specific categories of (potential) flexibility suppliers. The partial or complete exclusion of demand response is one example: demand response is not permitted for the supply of primary reserves in the Netherlands, and it is disallowed for secondary reserves in Belgium (see Table 2). Moreover, **prequalification requirements** may be imposed either at the level of the asset or at the level of a pool of assets. Requirements concerning minimum volumes or ramp rates, for example, are more restrictive if imposed on a single unit rather than on a pool of units. Unit-level requirements thus restrict the number of potential providers. Several countries in the PLEF region impose unit-based prequalification, including Belgium, Germany, and Austria (see Table 4).

Measurement and verification procedures are typically geared toward feed-in from centralised generation. Demand response requires its own alternate protocol for measurement and verification. This protocol is often referred to as the baseline methodology. The standardisation of requirements is meant to facilitate the contractual relationships between the end consumer, its supplier/BRP and the demand response aggregator. In several of the PLEF countries, one or more such baseline methodologies are already in place. However, in Germany for example the four German TSOs may establish their own criteria or have no publicly published criteria.

Communication requirements that may be imposed in order to facilitate the coordinated deployment of balancing energy typically presuppose that BSPs already have both dedicated staff and communications infrastructure to meet these requirements. Potential BSPs that are seeking to offer their services on a less frequent, more opportunity-driven basis (e.g. industrial parties) may find the existing requirements too demanding and that they come at too high a cost. The Austrian requirement of a dedicated telephone line linked directly to the TSO in order to provide demand response services is an example of such (SEDC 2014).

4.1.3 Product specifications

Product specifications are the requirements placed on products to be offered/traded on electricity markets. Below, we discuss minimum volume requirements, product duration, and symmetric bid requirements. These specifications may impose restrictive conditions on the supply of flexibility. **Minimum volume requirements**, which are both direct and explicit, may be considered as one example. These requirements establish the minimum volume that may be offered in a given market (see Table 5). Accordingly, minimum vol-

Aggregation level prequalification process for the three reserve market segments in the PLEF countries in 2015. Table 4

	R1	R2	R3
Austria	unit-based	unit-based	unit-based
Belgium	unit-based	unit-based	unit-based
France	pool-based	pool-based	pool-based
Germany	unit-based	unit-based	unit-based
The Netherlands	unit-based	pool-based	pool-based
Switzerland	pool-based	pool-based	pool-based

CE Delft and Microeconomix based on SEDC (2015).

Minimum volume requirements imposed in the reserves markets in the PLEF countries in 2015. Minimum volume requirements for DAM and IDM are uniformly set at 0.1 MW.[41] Table 5

	R1 [MW]	R2 [MW]	R3 [MW]	Special (DR) products [MW]
Austria	2	5	5	n.a.
Belgium	1	1	1 or 5 [42]	n.a.
France	1	1	10 [43]	25 (IL [44])
Germany	1	5	5	50 (IL)
The Netherlands	1	4	4 or 20 (ER [45])	n.a.
Switzerland	1	5	5	n.a.

CE Delft and Microeconomix based on TSO information.
Abbreviations: IL = interruptible load, ER = Emergency Reserves.

ume requirements may wind up excluding the offerings of smaller flexibility providers or require aggregate load and supply bids be allowed.

Minimum volume requirements are not typically limiting in the DAM or the IDM, where minimum volumes are set at 0.1 MW in all PLEF countries. In the reserve markets, often somewhat higher volume requirements are imposed, with minimum volumes typically set at some 1 to 5 MW. A volume requirement of 10 MW applies in France. This requirement was recently adjusted downward from the 50 MW minimum requirement that had been in place until 2014. In 2015, the French TSO RTE experimented with a minimum volume requirement of only 1 MW. Additional programmes, many of which are designed with large energy consumers in mind, may see restrictions running much higher; for example, in the Netherlands, emergency power is provided at a minimum of 20 MW, and the German interruptible load programme has set its minimum requirement at 50 MW.

Product duration can also be relatively restrictive for opportunity-driven participation. Product duration is generally defined as the span of time during which a product must be delivered. The longer the duration, the more restricted the potential number of providers becomes. In the event that operational reserves are pre-contracted, the product duration signifies this contracting period, i.e. the procurement period of reserves. As is the case for energy products, longer procurement periods successively restrict the number of possible providers. For energy products in the BM, explicit availability requirements apply; these requirements are typically set at 100 percent for primary and secondary reserves, while availability requirements for tertiary reserves may be somewhat more relaxed.

While product duration in both the DAM and the IDM typically ranges between 15 minutes and one hour, product duration for pre-contracted reserve power may be much larger. The German reserve power requirements, for instance, include an availability requirement of 12 hours for secondary reserves. Pre-contracted reserve products have durations varying between one week and one year in most PLEF countries. Daily products are a rare exception. The duration of the contracting period implies an equivalent

41 Note that higher minimum volume requirements can be compensated for in the market design if aggregation is allowed (see Table 1).

42 The minimum volume requirement is 5 MW for interruptible load and 1 MW for other products.

43 In 2015, RTE began experimenting with a minimum volume of 1 MW for tertiary reserves (mFRR and RR).

44 The French and German Interruptible Load (IL) programs are not formally part of the R3/mFRR dimensioning, hence they are tabulated as a separate product category.

45 The Dutch Emergency Reserves (ER) is part of the R3/mFRR dimensioning, hence it is tabulated as R3.

Product duration requirements imposed in the reserve markets in the PLEF countries in 2015. Note that product duration requirements for the DAM and the IDM are typically set at 1 hour, with the exception of the Austrian DAM and the Austrian, German, and Swiss IDMs that facilitate trading of 15 minute products as well. Table 6

	Temporal product resolution energy bids			Contracting period for operational reserves capacity bids			
	R1	R2	R3	R1	R2	R3	Spec. DR prods.
Austria	15 mins	12 hrs (WD), 48 hrs (WND)	4 hrs	1 week	1 week, 1 day	1 week	n.a.
Belgium	15 mins	15 mins	15 mins, 4 hrs (IL)	1 month	1 month	1 year (1 month for 10% fraction)	n.a.
France	30 mins	30 mins	30 mins	n.a.[46]	n.a.[47]	1 week or 1 year[48]	1 year (IL)
Germany	15 mins	12 hrs (WD), 48 hrs (WND)	4 hrs	1 week	1 week	1 day	1 month
The Netherlands	15 mins	15 mins	15 mins	1 week	1 year[49]	1 year	n.a.
Switzerland	15 mins	15 mins	4 hrs	1 week	1 week	1 day	n.a.

CE Delft and Microeconomix based on TSO information. Abbreviations: WD = weekday, WND = weekend, IL = interruptible load.

availability requirement. Regarding a portfolio (or pool) of generation assets, requirements have historically induced only limited risk given the generally ample availability of spinning reserves. If there are increasing renewable feed-in rates or if demand response resources reside with large energy consumers, requirements may prove relatively restrictive, since neither renewables nor demand response (e.g. small-scale storage) can commit resources over longer periods of time.

A final and important product specification concerns requirements in the **bundling of upward and downward balancing energy offerings** of pre-contracted reserves. Requirements may stipulate that balancing energy be offered symmetrically; where they do not, asymmetrical offerings are possible. Symmetric reserve products imply a joint, or bundled, bid for the supply of both upward and downward regulating energy. Hence, symmetrical offering requirements imply that flexibility providers must be able to provide both upward regulation and downward regulation.

While symmetric products may be well suited to conventional generation assets, such is not the case for demand response. Asymmetric offerings mean that separate bids may be made for upward and for downward regulation, and this then makes it easier for new market actors – specifically those seeking to market demand response – to provide balancing power that matches the technical properties of their units.

Symmetric product requirements apply to products for primary reserve power in most PLEF countries, to products for French secondary reserve power (R2 or aFRR), and to Swiss secondary reserve power (R2 or aFRR).

46 The case of R1 and R2 is quite different in France since producers (above a certain size) have an obligation to reserve some capacity. On D-1, the TSO computes the required R1 and R2 and shares out these volumes among producers based on their expected generation (for instance, a producer who does not expect to produce is not required to have any reserved capacity). Producers obliged to provide reserves can buy needed capacity in a "secondary" market. Thus, there is not an auction for capacity as in the other countries, but the obligation of contracted reserve is defined one day ahead and a price could appear in the secondary market.

47 See previous footnote.

48 The auction for the reservation is done Y-1 and considers the whole year, though bids are made on a weekly basis.

49 In 2016, the Dutch TSO TenneT will procure 50% of R2 and R3 capacity by means of quarterly contracts.

Symmetric bid requirements imposed in the reserves markets in the PLEF countries in 2015. Such requirements do not apply in the DAM or the IDM. Table 7

	R1	R2	R3
Austria	Symmetric	Asymmetric	Asymmetric
Belgium	Partially asymmetric [50]	Asymmetric [51]	Asymmetric
France	Symmetric	Symmetric [52]	Asymmetric
Germany	Symmetric	Asymmetric	Asymmetric
The Netherlands	Symmetric	Asymmetric	Asymmetric
Switzerland	Symmetric	Symmetric	Asymmetric

CE Delft and Microeconomix based on TSO information.

4.2 Market Completeness

Market completeness is a requirement of central importance for achieving efficient dispatch within markets. A market may be considered complete to the extent that the full set of forward and spot markets as well as risk management tools are available for each product in both time and space. A complete market that can facilitate the trade of electricity for delivery at any time to any place should allow seamless, risk-free, and frictionless arbitrage between short-term markets. The available literature concludes that welfare in incomplete markets is lower than in complete markets because in the former not all risk is perfectly allocated. In practice, markets are never complete, since not all risk factors are traded on the market (for example, risks relating to rare high-impact events). Two relevant causes for market incompleteness have been identified (see for example Willems 2008):

→ Markets may be missing for assets that hedge the class of risks one wishes to hedge.
→ There may exist transaction costs or trading constraints.

Since incomplete markets prevent the exhaustion of all potential gains from trading, establishing the market that is missing or relaxing trading constraints and/or costs would assist in improving allocative efficiency.

In short-term electricity markets, both causes of incompleteness may be present. Generally speaking, PLEF markets have yet to develop markets for products that hedge against price volatility across all short-term markets, and in the BM in particular. Such a market could be said to be missing. Given the highly non-linear nature of price dynamics in short-term electricity markets, a market for options would be desirable for the purpose of risk management. At present, options on futures are the only options traded, and these are traded predominantly in the Nordic countries and, to a limited extent, in the German market. Intraday options – called intraday cap futures by the European Energy Exchange, or EEX – were recently launched in Germany (Platts 2015). The idea is that, in buying these options, sellers of vRES production can protect themselves against short-term price spikes in the IDM. Short-term price spikes may occur when a cor-

50 The Belgian system for primary control distinguishes four categories: R1 symmetrical 200 mHz, R1 symmetrical 100 mHz, R1 upwards (typically load), R1 downwards. The first two categories involve symmetric products, while the latter do not. Average monthly procurement capacity for these categories in 2015 was 43 MW, 25 MW, 23 MW and 25 MW respectively.

51 There are two products mentioned on the website - R2 symmetric and asymmetric - but recently auctions have only been held for asymmetric products (up and downward)

52 Asymmetric products are expected to be introduced in France in October 2016 for R1 and R2.

relation in the forecast errors of different vRES producers is expected. When production forecast is overestimated, the IDM prices surge upward due to high demand for energy on the intraday market. On the other hand, in selling these options, generators with flexible capacity receive a fixed payment (the option premium) to stabilise their revenue streams. We can expect to see more such financial products introduced in the near future. The options concept could be extended to allow their exercise even after intraday gate closure in the form of Balancing Resource Options (BROs), as Pöyry (2015) has proposed. Such energy-specific options would allow market participants to hedge against imbalance risk.

Regarding the **existence of transaction costs** or **trading constraints**, note that the type and the temporal granularity of energy bids may impede efficient dispatch (for further detail, see Box 2). Additionally, the misalignment of trading periods and delivery periods can cause friction and hamper arbitrage. Alignment is discussed in more detail in the subsections below.

4.2.1 Alignment of Trading Periods

Misalignment of trading periods may hamper efficient arbitrage. For example, **gate closure time for pre-contracted reserve capacity** implies the foreclosure of all subsequent trading opportunities, given that the capacity allocated for reserves has to remain available for potential deployment in real-time. Bids for pre-contracted reserve capacity should therefore reflect the expected value as an opportunity cost. Weekly pre-contracting auctions in Germany and annual pre-contracting tender for reserves in the Netherlands are emblematic in that both require estimation of value in the DAM and the IDM well ahead of their realisation. In these instances, bids should reflect the forgone value in both markets, including foregone profits as well as whatever additional costs may accrue as a consequence of having to remain available for balancing purposes (i.e. to have spinning reserve available even when DA prices would not induce commitment).

Shorter term procurement of operational reserves will make it easier for agents to correctly estimate their opportunity costs, and this will lead to better allocation of resources for the system as a whole. Clearly, lengthy gate closure times generate exposure to opportunity costs so that a premium is required for the uncertainties involved, while erroneous estimations induce inefficiency in the resulting allocation (see for example Müsgens et. al. 2012). Just and Weber (2012), Neuhoff et al. (2015), and Hirth and Ziegenhagen (2015) all argue that countries with high shares of wind and solar power need to allow for the short-term procurement of reserves (within the time horizon of wind and solar forecasts) in order to enable these generation assets to have a reserve function. The possible introduction of day ahead auctions for reserve capacity that was recently announced in Germany would be in line with such a recommendation.[53] Dutch TSO TenneT recently moved to procure 50 percent of reserves in 2016 by means of quarterly contracts rather than the traditional yearly contracts, and this too may be considered a first step in the right direction. Standard practice in Germany presently requires energy bids to be placed alongside weekly bids for pre-contracted capacity, leaving uncertainty regarding potential power plant failures or load and vRES forecasting errors. Shorter term procurement will, on the other hand, reduce the time frame for corrective action on the part of TSOs. If generation is tight, for example, more time may be required to contract the required reserves. German TSOs are cautious about a dynamic procurement volume adjusted on a daily basis, since this would require an additional probabilistic assessment of the forecast errors and ramps for the next day. It is to the advantage of TSOs to be "on the very safe side," since they do not benefit from the lower price of reserves but will be held accountable for insufficient reserve procurement (Nabe and Neuhoff 2015). A number of other TSOs, however, would like to be able to activate/start-up generators to increase tertiary reserve capacity, as needed, several hours prior to real-time (Microeconomix 2015). In this case, the submission of "free bids" – i.e. energy bid submission up until the final hour prior to real-time – provides for enhanced degrees of freedom.

53 BMWi (2015): An electricity market for Germany's energy transition. White Paper by the Federal Ministry for Economic Affairs and Energy.

Box 2: Influence of the type and temporal granularity of energy bids on efficient dispatch

Type of energy bids

The literature identifies three types of bids: simple price-quantity bids, (linked or) block price-quantity bids, and complex (or multi-part) bids. In an auction with uniform marginal pricing, as is the case in the DAM in the PLEF region, it is clear that if there is no market power, the optimal bidding strategy for the agents is to bid their marginal price. Nevertheless, in practice simple bids and an optimal bidding strategy are incompatible because an agent cannot include his non-convex costs, the most important of these being the start-up cost. At the same time, these costs increase in prominence as the share of vRES increases in the mix.

One remedy which is often applied in the DAM in the PLEF region is to allow block bids. Different block bidding formats exist, though the general idea is the same: that minimum revenue needs to be made for the period of the block bid in order to accept it. Nevertheless, even with block bids, these non-convex costs cannot be explicitly represented and a mark-up (replicating e.g. start-up costs) needs to be included in the block bids. Neuhoff and Schwenen (2013), Neuhoff et al. (2015a), and Neuhoff et al. (2015b) provide five arguments in favor of complex bids, wherein non-convex costs are explicitly presented, over simple and block bids. Firstly, less informed (smaller) participants have greater difficulty in determining the optimal mark-up to incorporate in their block bids. If mark-ups are not set at an appropriate level, which is likely, the efficiency of the market outcome decreases, while transaction costs and the uncertainty for market participants increases. Secondly, market monitoring for block bids is almost impossible, as the underlying costs structure is not defined. By contrast, complex bids with energy bids as well as ramping and start-up cost nominations follow observable cost structures. Thirdly, energy only and block bidding does not lend itself easily to the provision of early and reliable unit-specific generation patterns. By using energy only bids, the flexibility of thermal generation assets cannot be made fully available to the market; generation is often optimized within the portfolio of utilities or aggregators with the implication that system operators have limited information on the ultimate generation pattern to be considered for flow calculations. Also, it is argued that in contrast to block bids, the reflection of technical characteristics in complex bids is more suitable for computation of market clearing. Lastly, with block bids, liquidity in standardised auctions might be undermined, as bids only are valid conditional on their being accepted for longer durations of time.

Temporal granularity of products

The finer the granularity of tradable products, the more volatile the prices will be. At the same time, the prices of products with finer granularity better reflect and reward the (expected) real-time value of flexibility in the system. Units can take advantage of price volatility when they can ramp up or ramp down more quickly. Flexible resources need clear signals to encourage investment and to deliver energy when they are needed, and more granular products can deliver these incentives. Also, with the increasing penetration of wind and solar power, demand and supply schedules need to be balanced on a shorter time interval, in order to reduce reserve requirements (Neuhoff et al. 2015a).

Additionally, shorter product lengths also contribute to the shift of risk from TSOs to Balancing Responsible Parties (Frunt 2011). Less intervention from the TSO will be required and thus fewer costs will need to be socialised (Henriot and Glachant 2013). Lastly, having more granular products in the market means that the deterministic imbalances will be more limited (Hirth and Ziegenhagen 2015). Besides, in the event that passive balancing is not allowed, balancing costs will be lowered. It is also important to mention that the finer the granularity of the bids, the higher the need for complex bids will be. One reason is the computational time for market clearing and the other reason is the fact that the shorter the time interval, the more difficult it becomes to incorporate non-convex costs in block bids (Henriot and Glachant 2013).

Alignment of trading periods in short-term electricity markets in the PLEF countries in 2015. Table 8

	DAM	IDM	(pre-contracted) operational reserves capacity bids			operational reserves energy bids			
			R1	R2	R3	R1	R2	R3	free (R3) bids allowed
Austria	D-1; 12h00 (EPEX), D-1; 10h12 (EXAA)	M-30	W-1	W-1	W-1	W-1	W-1, D-1[55]	D-1; 15h00	yes
Belgium	D-1; 12h00	M-5	MO-1	MO-1	mainly Y-1 (1 month for 10% fraction)	MO-1	D-1; 15h00	H-1	yes
France	D-1; 12h00	M-30	n.a.[56]	n.a.[57]	Y-1	n.a.	n.a.	H-1	yes
Germany	D-1; 12h00	D-1; 15h00 (auction), M-30 (continuous)	W-1	W-1	D-1	W-1	W-1	D-1	no
The Netherlands	D-1; 12h00	M-5	W-1	Y-1, Q-1	Y-1	W-1	H-1	H-1	yes
Switzerland	D-1; 12h00	M-30	W-1	W-1	D-1	W-1	W-1	D-1; 8h00	yes

CE Delft and Microeconomix based on TSO information. Abbreviations: Y = year, MO = month, W = week, D = day, H = hour, M = minute.

Additional degrees of freedom are also provided by the Dutch practice of publishing and updating the BM bid stack at M-15 and the activated balancing energy and balancing price at M+2 on a minute-by-minute basis.[54] These data allow the imbalance signal and regulation state for the next ISP to be estimated and, accordingly, allow for "passive contributions" to system balancing. In other words, BRPs may anticipate system imbalance and consequently be in a position to contribute to balancing by inducing portfolio imbalances directly counteractive (opposite) to the expected system imbalance. It is believed that contributions of this kind can result in a substantial reduction in the energy required for balancing (see TenneT 2011). In this case, BRPs should be legally authorized to respond to the price signal, which is currently not the case in every country.

Another instance of misalignment between trading periods may occur in the context of **cross-border trading in energy products** and the **cross-border capacity allocation** associated with this, in the intraday time frame in particular.

In order to align trading in cross-border energy products and cross-border interconnector capacity, trading periods would at the very least have to be synchronised. Ideally, allowance would also be made for these two products (energy and interconnector capacity) to be bundled or coupled when traded. In the early days of market-based cross-border capacity allocation, cross-border capacity was typically auctioned off by the TSOs in a process requiring explicit bidding by market participants – a process generally referred to as "explicit auctioning." This mechanism required explicit bids for cross-border capacity, which should have been based on the (expected) energy price differential across the respective border.

54 Other countries in the PLEF region publish this information with a delay only (e.g. > 15 minutes).

55 150 MW of R2 are tendered by the Austrian TSO on a weekly basis and 50 MW are tendered on a daily basis (APG 2015).

56 See footnote 46.

57 See footnote 46.

Intraday cross-border capacity allocation mechanism (high), gate closure (mid), and product duration (low) in the PLEF countries in 2015. Table 9

	Austria	Belgium	France	Germany	The Netherlands	Switzerland
Austria						
Belgium	n.a.					
France	n.a.	Explicit[58]				
Germany	Implicit & explicit	n.a.	Implicit & explicit			
The Netherlands	n.a.	Implicit	n.a.	Explicit		
Switzerland	Implicit & explicit	n.a.	Implicit & explicit	Implicit & explicit	n.a.	

	Gate closure domestic IDM	Gate closure for intraday cross-border capacity allocation					
		Austria	**Belgium**	**France**	**Germany**	**The Netherlands**	**Switzerland**
Austria	M-30						
Belgium	M-5	n.a.					
France	M-30	n.a.	H-1				
Germany	D-1; 15h00 (auction), M-30 (cont.)	H-1	n.a.	H-1[59]			
The Netherlands	M-5	n.a.	H-2	n.a.	M-70		
Switzerland	H-1	M-45	n.a.	H-1[60]	H-1	n.a.	

	Domestic IDM product duration	Product duration for cross-border IDMs					
		Austria	**Belgium**	**France**	**Germany**	**The Netherlands**	**Switzerland**
Austria	60 mins, 15 mins						
Belgium	60 mins						
France	60 mins		60 mins				
Germany	60 mins, 15 mins	15 mins		60 mins[61]			
The Netherlands	60 mins		60 mins		60 mins		
Switzerland	60 mins, 15 mins	15 mins		60 mins[62]	15 mins		

CE Delft and Microeconomix based on PX and TSO information.

While explicit trading in the day-ahead time frame required anticipation of the future price differential, erroneous forecasting of these differentials resulted in misallocation of cross-border capacity. This misallocation compromised allocative efficiency: not only did occasional adverse flows from high to low price markets take place, but cross-border capacity was then only partially exploited, even as arbitrage

58 The methodology in place for intraday cross-border capacity allocation on the French-Belgian border is referred to as a pro-rata mechanism, allocating capacity evenly across the number of participants. In the event the requested capacity is below this 'fair share', the remaining capacity is allocated evenly over the remaining participants (see also Intraday Capacity Allocation Rules for the French-Belgium Interconnection, version 2.0). Moreover, this methodology will change in 2016, toward an explicit continuous auction (on the basis of a first-come, first-served principle) in March and toward an implicit auction (which can take place on its own or with an explicit auction) before September.

59 The gate closure for explicit auctions is H-1 or M-90 since products are half-hourly and there are only 24 hourly gates.

60 See footnote 59.

61 For explicit auctions, products are half-hourly.

62 See footnote 61.

opportunities (i.e. price differentials) between the respective markets remained unexploited. The introduction of "implicit auctioning" under the so-called trilateral market coupling of the Dutch, Belgian, and French day-ahead markets in November 2006 effectively resolved these inefficiencies. This new mechanism involved implicit allocation of cross-border capacity to cross-border energy trades that resulted from an integral evaluation of the bid stack in the coupled day-ahead markets. Since then, all DAM markets in the PLEF countries have been coupled implicitly.

In the case of continuous intraday trading, the dynamics of explicit trading arrangements differ somewhat, given that the price differential can, in principle, be observed from the order book. In other words, the price differential across the interconnector is known when a bid for cross-border capacity is submitted. Nevertheless, explicit continuous trading of cross-border capacity requires multiple steps relating to the trade of energy as well as cross-border capacity in order to secure the arbitrage opportunity, and it also leaves exposure during execution. Furthermore, explicit auctioning of the interconnector capacity does not allow for netting (i.e. when a capacity allocation in one direction opens up an equivalent capacity in the opposite direction), given that the usage of the capacity is not assured before real-time. Finally, since cross-border capacity is allocated on a first-come, first-served basis, rapid early trades are favored instead of efficient ones (Neuhoff et al. 2015). Hence, inefficiencies in explicit auctioning for cross-border allocation remain, as discussed in section 3.3.3 and illustrated in Figure 12. Implicit continuous allocation of cross-border capacity implies instantaneous clearing of cross-border interconnector capacity when a cross-border intraday energy trade is cleared. In addition, implicit continuous allocation is also expected to contribute to IDM liquidity, much like prior implementations of implicit auctioning in the day-ahead time frame.

Implicit allocation of cross-border intraday capacity, which takes place on continuous trading platforms, is currently in effect along several borders in the PLEF region (along the borders between the Netherlands and Belgium and within the region of Germany, France, Switzerland, and Austria), though in other instances it is not in effect (for example, along the border between Belgium and France). In tandem with this implicit allocation mechanism, explicit allocation is also available across several borders in the PLEF region; in such instances, the two mechanisms operate in conjunction. In addition to differences in the mechanisms of allocation, gate closure and product duration may also diverge. An overview of these data for the PLEF countries is provided in Table 9.

Implicit continuous intraday trading has been adopted in the target model and, as of 2010, a broad coalition of TSOs and Power Exchanges (PXs) have been working on creating a unified intraday cross-border trading platform for continuous trading and implicit allocation of cross-border capacity. This project is known as XBID[63] and is expected to be launched by June 2017. Two primary benefits are expected from XBID: full implementation of continuous trading and the implicit allocation of cross-border capacity. However, for the target model requirements to be fully implemented and to conform to the guideline on capacity allocation and congestion management (CAMC),[64] a trading scheme is needed that not only allows for the trading of capacity continuously and implicitly but that also provides a congestion pricing mechanism.[65]

The target model as well as the XBID project aim to develop a unified framework for cross-border ID trade with implicit allocation, where implicit allocation involves automated capacity reservation and nomination by the clearing house. Such a framework is not currently in place. The allocation of

63 See http://www.tennet.eu/nl/fileadmin/downloads/Customers/News/06_Cross-Border_Intraday_Market_Project.pdf for a project overview.

64 Commission Regulation (EU) 2015/1222.

65 Currently, the price for ID capacity is set to zero in the coupling algorithm. Thus, the foregone value of this capacity in the DA timeframe is zero. Hence, DA XB capacity allocation disregards the value (i.e. need) of XB capacity reservations for the ID market (and the BM, if BM would be coupled in future). Hence, capacity is purely allocated on the basis of DA needs and disregards ID needs, such that the current practice induces over-allocation in the DA timeframe and XB trading is overly restricted. This hampers ID XB trading. ID XB capacity pricing would offer a basis for price driven XB capacity allocation across the DA and ID time frames.

intraday transmission capacity could be seen as an argument in favor of holding intraday auctions rather than allowing continuous trading.[66] This way, these intraday (energy) auctions could simultaneously allocate transmission capacity.

4.2.2 Alignment of delivery periods

Alignment of delivery periods will contribute to the efficiency of the different short-term electricity market segments, as it allows for efficient arbitrage and risk management. The main differentials encountered in time involve the increasing temporal granularity (i.e. the shortening of the settlement period) of the products traded when moving from the DAM to the BM (see Table 1). A case in point is the Dutch market, in which only hourly products (and block products) are traded in the DAM and the IDM, while 15 minute products are traded in the BM. Clearly, when the imbalance settlement period[67] involves 15 minute values, these markets will allow only for partial hedging of imbalance exposures. Such differentials also appear across borders with ISPs of 15 minutes in most of the PLEF countries – except for the French ISP, which is set to 30 minutes. Such differentials imply that frictionless trading cannot be achieved and that inefficiencies will remain. In addition, cross-border capacity products should also be aligned with the ISPs, so that these capacity products can match any energy products used to limit BM exposures, as was discussed in the previous section.

In Germany, ISPs are set to 15 minutes, but primary and secondary capacity and energy reserves products are bid in week-ahead and cover either peak or off-peak products for the full week (see Table 6). Hence, these bids essentially entail block bids rather than atomistic bids per ISP. Given that such (capacity and energy) products provide for the offers of last resort to manage imbalances, the impact of such bundled offers is likely to spill over into the preceding markets as well as the imbalance settlement prices impose a penalty on portfolio imbalances.

4.3 Market Pricing

Several of the market design elements related to pricing were already raised in section 2 of this paper, as the pricing mechanisms for short-term markets directly affect compli-

66 Note that an intraday auction was introduced for the German control block in December 2014, in addition to the already operational continuous intraday market.

67 For each ISP, BRPs have to submit schedules/programmes for both infeed and offtake of electricity. If actual in-feeds or off-takes diverge from the programme/schedule, penalties in the form of the imbalance settlement price have to be paid.

Alignment of delivery periods in short-term electricity markets in the PLEF countries in 2015. Table 10

	Temporal product resolution energy bids				
	DAM	IDM	R1	R2	R3
Austria	60 mins, 15 mins	60 mins, 15 mins	15 mins	12 hrs (WD), 48 hrs (WND)	4 hrs
Belgium	60 mins	60 mins	15 mins	15 mins	15 mins, 4 hrs (IL)
France	60 mins	60 mins	30 mins	30 mins	30 mins
Germany	60 mins	60 mins, 15 mins	15 mins	12 hrs (WD), 48 hrs (WND)	4 hrs
The Netherlands	60 mins	60 mins	15 mins	15 mins	15 mins
Switzerland	60 mins	60 mins, 15 mins	15 mins	15 mins	4 hrs

CE Delft and Microeconomix based on TSO information. Abbreviations: WD = weekday, WND = weekend, IL = interruptible load.

ance with the marginal pricing principle. Accordingly, the applied pricing methodology is a market design parameter with a strong impact on allocative efficiency. For DA markets, uniform (marginal) pricing based on a daily auction applies across the board. For IDMs, continuous trading is typically the dominant trading mechanism; thus, a pay-as-bid pricing applies. In the case of BMs in the PLEF region, our discussion previously revealed that the pricing mechanism differs from country to country. It also differs for imbalance settlement and the supply of balancing services. In the following discussion, we distinguish between two relevant aspects of market pricing:

→ Pricing mechanisms
→ Price restrictions

In addition, one may note that all of the BM pricing mechanisms in the PLEF region include additional penalty factors. These penalty factors are intended to incentivise self-balancing and may be set differently over time, typically in response to extended periods of heightened system imbalance. Alternatively, they may differ as the level of system imbalance increases, or as balancing energy provision tightens.

4.3.1 Pricing Mechanisms

The pricing mechanism refers to how prices are set when supply and demand are cleared in markets. As discussed in section 3.3.1, the efficient allocation of short-term markets is induced by marginal pricing and, ideally, such a mechanism applies in all market segments. In practice, however, only the DAM pricing mechanism complies with marginal pricing across the entire PLEF region, while alternative pricing schemes are in place in several of the other short-term markets. IDM pricing in the PLEF countries is based on the pay-as-bid pricing principle, given the nature of continuous trading.[68] Pricing practices in the BM across the PLEF region make use of a wider spectrum of mechanisms.

To characterise the BM pricing mechanism, one should first distinguish between the BM market price and the imbalance settlement price. The BM is typically organised as a single-buyer market, with the TSO as the single buyer that procures balancing energy from the BSPs. The TSO then passes the cost of balancing energy on to the BRPs that have caused the imbalances, which are then corrected through an imbalance settlement scheme. This structure has arisen as a consequence of the centralised coordination of imbalance management through the TSO, and not so much as a matter of intentional market design. Pricing mechanisms could therefore be designed such that they replicate, say, marginal pricing as applied in the DAM. Such a scheme would imply symmetric pricing, i.e. the same prices would apply to both the BRP and the BSP. The Dutch employ a similar scheme, if one disregards the penalty scheme that applies in these markets. Further, the Dutch scheme departs from symmetric pricing in the event that both positive and negative balancing actions are taken within a single settlement period; in such case, the two actions are then priced independently.

Pricing mechanisms, as applied to imbalance settlement, can be defined as either single or dual. Single pricing refers to the mechanism by which both short and long BRP positions are settled at identical prices, whereas dual pricing settles these at different prices. In case of a single imbalance settlement price, the settlement price is typically above DAM level when the system is short and below DAM level (it can even be negative) when the system is long. A long or positive BRP imbalance position means that the TSO makes a payment to the BRP (unless, of course, the imbalance settlement price is negative). Hence, the BRP will be rewarded with an imbalance settlement price above DAM D-1 levels in the event the system is short and penalized with an imbalance settlement price below DAM D-1 levels in the event the system is long. Analogously, with a short, or negative, BRP imbalance position, the BRP must pay the TSO (unless the imbalance settlement price is negative). In this case, the BRP will be penalised by the TSO with an imbalance settlement price above DAM D-1 levels in the event the system is short and rewarded by the TSO with an imbalance settlement price below DAM D-1 levels in the event the system is long. In other words, when the BRP position correlates with the system imbalance, the cost of imbalance is paid for by the BRP. By contrast, when the BRP position is opposite that

68 In Germany, an intraday auction with marginal pricing exists as well; see also footnote 66.

Box 3: Single versus dual imbalance settlement pricing

A vast body of literature is available on the advantages and disadvantages of single versus dual pricing. Favourable aspects of the single pricing scheme cited in the literature can be summarised as follows:

- **Accessibility:** Dual imbalance pricing discriminates against smaller generation units and smaller portfolios, in the event that portfolio imbalances are allowed to be aggregated (Neuhoff et al. 2015a). This is especially the case if there is no liquid intraday market (Chaves-Ávila et al. 2014). With a single imbalance price, market participants do not need to physically pool imbalances across a portfolio to reduce exposure to imbalance, but can equally address this exposure by means of financial hedges.
- **Cost-reflectiveness:** The dual price imbalance design is reputed to be less cost-reflective than the single price design (Newbery 2005). As the system balancing cost does not depend on individual imbalances but on the total net imbalance, positive or negative individual imbalances need to have the same price (Hiroux and Saguan 2010). Further, the reverse price, i.e. the individual imbalances in the opposite direction of the system imbalance in a dual price system, has been deliberately 'delinked' from the System Operator's costs. In fact, it is typically linked to DAM prices, distorting price discovery (Littlechild 2007).
- **Allocative efficiency:** Both short or long participants can make an effective contribution to balancing the system, but the dual cash-out mechanism encourages only one set of market participants to do so (Littlechild 2007). Further, the width of the gap between the system buy and the system sell price affects decisions on self-balancing versus reliance on the facilities of the TSO (the make-or-buy decision). Hence, many market participants seem to have taken the view that being short is to be avoided at almost all costs, which is unlikely to be efficient.
- **Price transparency;** Lastly, it should be noted that a single imbalance settlement price would constitute to a suitable liquid reference price (Littlechild 2007).

In contrast, favourable aspects of the dual pricing scheme cited in the literature can be summarised as follows:

- **Dual system states:** If the imbalance in one settlement period changes from positive to negative (or the other way around), for one of these imbalances, the imbalance price will send adverse price signals and the wrong incentives (Brunekreeft 2015). The current practice in the Netherlands – a hybrid system that consists of a single pricing mechanism but provides for a shift to dual pricing when the imbalance changes from positive to negative within a single settlement period – circumvents this drawback.
- **Market power:** A dual price mechanism may reduce the likelihood of market power abuse in comparison to a single price system (Littlechild 2007), a mechanism that was modelled by Khalfallah and Rious (2013). More precisely, if a large volume of electricity were to pass through the imbalance settlement mechanism instead of via bilateral trading, a dual imbalance settlement price would incentivise market participants more strongly to enter into contracts to balance their own positions before gate closure of the BM, rather than to rely unduly on the cash-out mechanism.
- **Cross-border aspects:** Chaves-Ávila et al. (2014) explain too that a single pricing scheme for a whole country can lead to misleading imbalance prices in the context of internal congestion. In that case, market parties can be incentivised to exacerbate their local imbalance if the direction of imbalance lies opposite in different areas.

A single pricing scheme is often favored over a dual pricing scheme. Particularly with regard to market design in the face of the flexibility challenge, one may note that the benefits of single pricing largely enable flexibility provision.

of the imbalance, the BRP receives payment. Fundamentally, then, the BRP imbalance position supports system balancing, in that it reduces the imbalance of the total system. In the case of dual pricing, pricing of BRP positions correlating with system imbalance (BRP positions aggravating system imbalance) differs from pricing for the opposite position (BRP positions reducing system imbalance).

A vast body of literature is available on the advantages and disadvantages of single versus dual pricing (see Box 3). A single pricing scheme is often favored over a dual pricing scheme. Particularly with regard to market design in the face of the flexibility challenge, one may note that the benefits of single pricing largely enable the supply of flexibility.

Lastly, imbalance settlement prices, or imbalance price formulas, differ across the PLEF region. Marginal pricing is only applied in Belgium and the Netherlands, while average pricing is applied in the other markets. Typically, the gross volume-weighted average price of balancing energy applies, which is to say that BRPs are charged for the cost of balancing energy based on the average cost per activated unit of energy. As described in section 3.3.1, the German mechanism is an exception in this respect, as the net (not gross) volume-weighted average price of balancing energy applies. This formula induces relatively high prices for small net regulation volumes, since averaging is done based on small net volumes, while total cost reflects the gross value of the activated volumes. In addition, price formulas also impact market volatility.[69]

The literature favors marginal pricing over a pay-as-bid pricing scheme in the BM, but there is acknowledgement that, given certain characteristics of the balancing market, this rule may be difficult to apply in some situations (see Box 4).

BSPs are typically remunerated through pay-as-bid schemes in the PLEF countries (see Table 1). Only the Netherlands remunerates secondary and tertiary balancing energy through marginal pricing. As for BRPs, they are typically charged with average prices. Pay-as-bid schemes are thought to induce inefficiencies, since it incentivises inframarginal bidders to bid up to the expected marginal price in order to capture inframarginal rents. If the marginal price in each imbalance settlement period were known

69 Hiroux and Saguan (2010) state that a marginal price design is reputed to give more volatile signals if the imbalance price is computed using the proposed price of the marginal offer or bid since this can change for each settlement period. Neuhoff et al. (2015) argue that this volatility, which is caused by fewer system assets that can respond on short notice, is favourable. It will incentivise companies to balance their position as early as possible in order to reduce exposure to these volatile prices.

Box 4: Marginal pricing in the balancing market

Littlechild (2007) argues that the marginal price may be susceptible to manipulation where there are relatively few offers and bids. Also, in a more recent paper, Littlechild (2015) states that in the balancing mechanism near real-time, the system operator does not see a nice stack of energy trades but rather must choose from among a plethora of up and down actions, each with different dynamic characteristics in the presence of noisy need. Some of these might be attractive enough to hold onto over several trading periods. Others will need to be reversed in favor of new opportunities or will come to an end as a result of self-dispatched movements. In such a context, the concept of marginal cost is a tenuous one. Another problem arises when different products of different reserve types, for example secondary reserves (R2/aFRR) and tertiary reserves (R3/mFRR), are used in the same instance. In the Netherlands, uniform pricing is applied and the price is set by the highest bid from among the two reserve types, even if this most expensive unit has only been activated for a very short fraction of the imbalance settlement period (E-Bridge consulting GmbH and IAEW 2014).

Imbalance settlement pricing mechanisms in the PLEF countries in 2015. Table 11

	Imbalance settlement pricing mechanism	Imbalance settlement price (imbalance pricing for imbalances that aggravates system imbalance)	Reverse imbalance settlement price (imbalance pricing for imbalances that reduce system imbalance)
Austria	Single	MAX((net cost/GRV); DAM ; IDM) + sign(NRV) * MIN(U_{max}, U_{min} + (U_{max} - U_{min}) * (NRV/V_{max})^2, if NRV > 0 MIN((net cost/GRV); DAM ; IDM) + sign(NRV) * MIN(U_{max}, U_{min} + (U_{max} - U_{min}) * (NRV/V_{max})^2, if NRV < 0 U_{min} = min surcharge, U_{max} = monthly max surcharge, V_{max} = min volume max surcharge	
Belgium	Single, if abs(SI) < 140 MW	MAX(aFRR; mFRR), if NRV > 0 MIN(aFRR; mFRR), if NRV < 0	
	Dual, if abs(SI) > 140 MW	MAX(aFRR; mFRR) + α_2, if NRV > 0 MIN(aFRR; mFRR) - α_1, if NRV < 0 α_1, α_2 = (1/8) * $\sum_{(t-7)}$(SI per ISP)^2/15,000	MAX(aFRR; mFRR) - β_1, if NRV >0 MIN(aFRR; mFRR) + β_2, if NRV <0 β_1, β_2 = 0
France [70]	Dual	MAX((net cost/GRV) * (1+k); DAM), if system is short MIN((net cost/GRV) / (1+k); DAM), if system is long k = 0.08	DAM
Germany	Single	MAX(IDM; sign(NRV) * MIN(abs(net cost/NRV); abs(MAX(FRR; RR))) + surcharge, if NRV > 0 MIN(IDM; sign(NRV) * MIN(abs(net cost/NRV); abs(MAX(FRR; RR))) + surcharge, if NRV < 0 surcharge = sign(NRV) * min(50% * balancing energy price, 100€MWh), if SI > 80% contracted FRR	
The Netherlands	Hybrid [71]	MAX(aFRR; mFRR; ER) + incentive component, if regulation volume is positive MIN(aFRR; mFRR; ER) - incentive component, if regulation volume is negative incentive component mostly zero	MAX(aFRR; mFRR; ER) - incentive component, if regulation volume is positive MIN(aFRR; mFRR; ER) + incentive component, if regulation volume is negative incentive component mostly zero
Switzerland	Dual	(MIN(DAM; FRR; RR) - P_2) * α_2, if BRP is long & NRV > 0 (MAX(DAM; FRR; RR) + P_1) * α_1, if BRP is short & NRV < 0 P_1 = 10 €/MWh, P_2 = 5 €/MWh, α_1 = 1.1, α_2 = 0.9	(MAX(DAM; FRR; RR) + P_1) * α_1, if BRP is short & NRV > 0 (MIN(DAM; FRR; RR) - P_2) * α_2, if BRP is long & NRV < 0 P_1 = 10 €/MWh, P_2 = 5 €/MWh, α_1 = 1.1, α_2 = 0.9

CE Delft and Microeconomix based on TSO information.
Abbreviations: GRV = Gross Regulation Volume, NRV = Net Regulation Volume, SI = System Imbalance, ER Emergency Reserves.

in advance with perfect foresight, this would result in the same (efficient) allocation as marginal pricing. Since this is not the case, however, such bidding behaviour is likely to diverge from marginal pricing, thus inducing inefficiencies in allocation. Charging BRPs average prices induces inefficiencies, as this mechanism socialises the marginal cost of imbalances, thereby typically inducing only moderate price increases as system imbalances increase.

Table 11 presents an overview of imbalance settlement pricing in the PLEF countries. In the current markets, the German and the Austrian schemes exemplify the single pricing mechanism, disregarding the penalty schemes. The Dutch scheme can be characterised as a hybrid system that complies with single pricing only when either exclusively positive or exclusively negative balancing actions were taken within a given settlement period. In the event that the imbalance in a single settlement period changes from positive to negative (or the other way around), dual pricing is applied. On the other hand, the French and Swiss schemes exemplify dual pricing mechanisms.

70 The imbalance settlement pricing mechanism will be modified in January 2017: the DAM price will no longer be used and the price for imbalances that reduces the system imbalance will be based on the costs of balancing energy

71 The Dutch system may be characterised as a hybrid system, as the imbalance settlement price differential results from an incentive component that is generally set to zero. The incentive component is adjusted on the basis of weekly system imbalance statistics. In addition, a price differential may arise if both positive and negative regulation volumes are activated within on ISP.

Differentiation in pricing may result when penalties are applied to BRPs whose positions correlate with the system imbalance (i.e. when the imbalance is, for instance, positive for both the BRP and the system). Such penalties seek to incentivise self-balancing. The pricing mechanism may also differentiate between balancing energy pricing and imbalance settlement pricing. In the case of France, however, different formulas apply. In this case, average pricing applies to BRP positions correlating with system imbalance, while DAM D-1 pricing applies to BRP positions opposite that of system imbalance. Given dual pricing in the French imbalance settlement scheme, were a BRP to take an opposite position to that of the system imbalance in order to achieve stability, this would not benefit the BRP financially – as would, for instance, participating instead in the DAM. The French scheme thus leaves untapped the potential for passive contributions, in this respect.

4.3.2 Price Restrictions

In order to allow for unconstrained price discovery in the short-term electricity markets, prices should be allowed to attain any value. In practice, price caps and floors apply in all short-term markets, either as price controls designed to prevent price manipulation or simply for administrative reasons.[72] DAM price caps were harmonised in the CWE region in 2014, when a minimum price was set at -500 €/MWh and a maximum price at 3000 €/MWh. In the IDM, a wider pricing range applies, with caps of, respectively, +/-9,999.99 €/MWh across the PLEF region. Germany recently introduced an additional intraday auction; the price cap and floor there, exceptionally, are set at +/-3000 €/MWh. There is no theoretical rationale for limiting price floors (Henriot 2012), and, with increasing demand side participation, increasing storage possibilities, and weaker market power, there are fewer and fewer reasons to hold on to price caps as well. No price cap will provide market participants any higher degree of planning security.

In the reserve and balancing markets, price caps differ from one control area to the next. In the procurement of balancing energy, restrictions may apply. These pricing restrictions are often differentiated for secondary reserves (R2/aFRR) vs. tertiary reserves (R3/mFRR) and for pre-contracted sup-

72 In the Dutch DAM, for example, a rare occurrence of cooling water scarcity in August 2004 induced prices to hit the cap over extended periods of time. In response, the price cap was raised in two steps from 1500€/MWh to 3000€/MWh, so that the cap was not maintained as a price control mechanism.

73 This price is defined as the balancing price when strategic reserves are activated.

Price caps for energy bids in short-term electricity markets in the PLEF countries in 2015. Table 12

	DAM	IDM	R1	R2	R3
Austria	[-500.00; 3,000.00] (EPEX), [-150.+00; 3,000.00] (EXAA)	[-9,999.99; 9,999.99]	n.a.	Minimum at quarterly DAM price EXAA (for imbalance price)	n.a.
Belgium	[-500.00; 3,000.00]	[-9,999.99; 9,999.99]	none	[0; fuel cost of a CCGT unit with electrical efficiency of 50 percent + 40€/MWh]	Upwards: [0; 4,500€/MWh[73]] Downwards: no constraint
France	[-500.00; 3,000.00]	[-9,999.99; 9,999.99]	EPEX price	EPEX price	Upwards > 0
Germany	[-500.00; 3,000.00]	[-9,999.99; 9,999.99]	none	none	none
The Netherlands	[-500.00; 3,000.00]	[-9,999.99; 9,999.99]	none	[DAM (D-1) -1000; DAM (D-1) +1000]	[DAM (D-1) -1000; DAM (D-1) +1000]
Switzerland	[-500.00; 3,000.00]	[-9,999.99; 9,999.99]	n.a.	Up regulation: [weekly base price; hourly DAM D-1 price +20%]	n.a.

CE Delft and Microeconomix based on PX and TSO information.

ply vs. the remainder. In Belgium, for example, secondary reserve (R2/aFRR) bids are restricted by a floor set at 0 EUR/MWh and a cap set at the marginal cost of a natural gas fired unit (with electrical efficiency of 50 percent) +40 EUR/MWh. In the Netherlands, pre-contracted bids are limited to DAM D-1 at +/-1000 EUR/MWh. Of course, if imbalance settlement is directly linked to the cost of balancing energy, such caps transfer to imbalance settlement prices as well. In addition, explicit price restrictions for imbalance settlement prices may apply. Typically these are restricted by a floor set at DAM D-1 prices, as is the case in France and Switzerland.

4.4 Conclusions

Following the empirical evaluation of the mechanics of short-term markets in a subset of the PLEF countries in section 3, in this section we evaluate in greater detail a series of market design parameters in the PLEF countries, with a view to their potential to enable flexibility. Previously, three dimensions for evaluation were proposed: *market access, market completeness, and market pricing*. The first dimension, which defines requirements for market participation, may not be entirely technology - and actor neutral – consider, for instance, explicit demand response participation in the different short-term markets. The second dimension describes to which extent existing arrangements in short-term markets may limit the trade of electricity for delivery anywhere and at any time. Market completeness also describes the degree to which arbitrage between short-term markets is seamless, risk-free, and frictionless. The third dimension refers to pricing methodologies and the restrictions related to these in each of the short-term markets. Below, these three dimensions are considered in light of market design elements that, as yet, have not been sufficiently accounted for in the market designs of the PLEF countries.

The foregoing discussion related to **market access** has shown that access to the market for demand response options, i.e *(aggregate) demand side participation*, is a critical issue, despite the fact that demand response has long been acknowledged as a valuable resource for the effective functioning of short-term electricity markets. Traditionally, in the PLEF countries, demand response has not been integrally accounted for in the short-term markets, most notably in the reserve and balancing markets. In recent years, however, many reserve and balancing markets have opened up for large-scale (aggregate) demand side participation. Still, it appears that factors enabling this participation have yet to be taken into account in all PLEF short-term markets. Aggregation, which is believed to be just such an enabling factor for small scale flexibility and demand response activation, remains an activity that is only marginally institutionalised. Its role and related responsibilities remain to be defined in most short-term markets in the PLEF countries. Like (aggregate) demand side participation, product specifications have also been adjusted from the perspective of accessibility in many of the reserve and balancing markets in the PLEF countries in recent years. *Minimum bid requirements* and *symmetry requirements* in particular were relaxed in various markets. Requirements set for *product duration*, on the other hand, could stand to be further relaxed in order to bolster flexibility.

From the perspective of **market completeness**, *alignment of trading periods and delivery periods* would be a relatively marginal adjustment of market design with potentially great effect. In the case of contracting *pre-contracted operational reserve capacity*, such a process often requires commitments well ahead of real-time and, as such, confronts market participants with significant uncertainty regarding the foregone value of the capacity (i.e. in terms of opportunity cost). A particular strand of complexity emerged in our analysis of *cross-border capacity allocation in the intraday time frame*. Forecast errors for vRES tend to induce an increase in demand for corrective programme adjustment in the intraday time frame – a demand that typically emerges within confined geographical regions. Intraday cross-border trading may therefore offer significant potential for corrective programme adjustment to balance supply and demand. This minimises both the exposure of BRPs to imbalance payments and the deployment of balancing energy by the TSOs. However, existing cross-border capacity allocation arrangements are not yet perfectly geared to enable liquid intraday cross-border trading. Implicit allocation has already been introduced in a number of cases, but the clearly advantageous approach of *aligning capacity product definitions with the energy products* is seldom taken. This is also the case for intraday products vis-à-vis balancing market products and, notably, *product granularity*. Here it should be noted that improved cross-border intraday trading not only improves the supply of flexibility in a time frame critical for enabling program adjustment, but improved cross-border trading also has the potential to improve liquidity and the efficiency of the intraday market at large.

Finally, as far as **market pricing** is concerned, the balancing markets in the PLEF countries reveal a wide range of pricing methodologies. Though the subject of *balancing energy pricing* was only touched on above, it was noted that the pay-as-bid mechanism is the dominant balancing energy pricing mechanism at play in the PLEF countries. With regard to *imbalance settlement pricing*, fundamentally dissimilar pricing methodologies are applied across the PLEF region. Single pricing mechanisms are in place in several of the PLEF countries, while dual pricing is applied in others. Furthermore – and this does not necessarily follow from or correlate with the previous distinction – several PLEF countries apply average pricing methodologies to determine imbalance prices rather than the marginal pricing method. In addition, incentive components apply to imbalance settlement pricing in all PLEF countries, in the form of either additive or multiplicative elements. Finally, most short-term markets in the PLEF countries, from day-ahead to balancing markets, show price restrictions in the form of caps and floors. Both the incentive components as well as the price restrictions distort the process of price discovery and, with that, the cost-reflective valuation of flexibility in the balancing market. Imbalance prices should reflect the real-time value of electricity. In order to support efficient resource allocation in this market as well as the preceding day-ahead and intraday markets (where most of the flexibility is traded). Nevertheless, imbalance pricing remains a design element that typically diverges from marginal pricing in the balancing markets in the PLEF countries. Typically, a range of pricing rules limits the price volatility associated with the real-time value of flexibility, hampering both the incentive to minimise flexibility needs as well as the incentive for efficient deployment of flexibility.

5 Pathways for Robust Market Design, Enhanced Market Integration, and Efficient Pricing

The previous sections presented an evaluation of the short-term electricity markets in PLEF countries. Section 3 presented an empirical evaluation of the short-term electricity markets in four PLEF countries in order to develop a sound understanding of pricing in short-term electricity markets as a coordinating mechanism for encouraging flexibility. Section 4 provided a more detailed evaluation of a series of market design parameters with a view to their capacities to enable efficient system allocation and thus to facilitate the provision of flexibility. Analyses done in both sections lead to the conclusion that the short-term markets in the PLEF countries could be better adjusted for efficient flexibility provisioning. Adjustments would also enhance integration across national markets.

Evaluation of the **balancing markets** in the PLEF countries reveals a wide range of differences – not only with respect to fundamental design elements such as the pricing mechanism, but also with respect to more particular elements. For instance, access to the market differs among countries for several increasingly relevant flexibility categories and there are also differences in the elements that induce frictions in general short-term market trading.

With regard to fundamental aspects of balancing market design, it should be noted that *marginal pricing* does not typically apply in the PLEF balancing markets, neither in the case of balancing energy nor in the case of imbalance settlement pricing (notably in systems with a dual pricing mechanism in place). Thus, when pricing does not follow the marginal pricing principle, efficient allocation is negatively affected (this also affects preceding intraday and day-ahead markets). The German imbalance settlement pricing procedures, for example, exacerbate this situation, since, on the one hand, the actual pricing mechanism induces additional volatility for low net regulation volumes and, on the other, information on actual imbalance settlement prices is not published until long after realisation. As sections 3.2.1 and 3.2.3 illustrate, this compromises not only effective arbitrage between the intraday and balancing markets but also cross-border arbitrage in the intraday time frame.

Our findings align with several of the provisions in the Network Code on Electricity Balancing.[74] The Network Code stipulates that the proposed pricing method for balancing energy shall be based on marginal pricing (pay-as-cleared) and *single pricing for imbalance settlement*. The code allows for application of dual pricing, provided it is based on clear criteria and is well justified. Furthermore, according to the code, imbalances are to be settled at a price that reflects the real-time value of energy.

Regarding the detailed evaluation of market design elements that induce friction in short-term trading, we have observed a progressive relaxation in a number of restrictions over the past several years. Still, aspects like *product duration* and *gate closure for reserve capacity* represent a significant barrier to flexibility provisioning, not only for new categories of flexibility providers but also for conventional flexibility providers (albeit to a lesser extent). Generally speaking, increased contracting frequency, shortened contracting periods, and shortened gate closure times would all allow for enhanced valuation of a given product as well as account for the foregone value of capacity in other market segments. These measures would enable more accurate pricing by flexibility providers, enhance flexibility price discovery, and reduce the risks involved for flexibility providers. Further alignment of trading and delivery periods would, in addition, reduce friction in the arbitrage processes and thereby contribute to the overall robustness of the short-term electricity markets in the PLEF region in terms of market resilience. However, one should be aware that in-

74 Annex II to Recommendation of the Agency for the Cooperation of Energy Regulators No. 03/2015 of 20 July 2015 on the Network Code on Electricity Balancing.

creased contracting frequency and shortened contracting periods may imply a heightened risk of market power abuse, given that long-term contracting classically acts to curb market power. Yet again, market conditions are changing in response to increasing competition, and competition has increased as a result of the increasing penetration of new technologies, new participants, and new opportunities for cross-border exchanges. Changed market conditions may allow traditional reliance on long-term contracting to be relaxed in order to improve arbitrage efficiency and to enable diversified and increased flexibility provision.

As was the case for pricing in the balancing market, these findings also align with several of the provisions in the Network Code on Electricity Balancing.[75] The Network Code stipulates that the procurement of balancing capacity shall be done as close as possible to real-time, while contracting should take place maximally one month in advance of the provision of the balancing capacity. No contracting period shall extend beyond one month. In addition, balancing energy gate closure time should also be as close as possible to real-time. Furthermore, the balancing energy gate closure should take place after the intraday cross zonal gate closure time for all balancing energy bids and should avoid as far as possible overlap with the intraday and balancing markets.

The **day-ahead** and **intraday markets** revealed themselves as more closely aligned with the three principles of efficient pricing introduced in Section 3. Detailed analysis in Section 4 of the design features of these markets revealed that they are relatively well aligned with the principles determining market access, market completeness, and market pricing. Improvements remain to be made, however, in the *linkage between cross-border trading and cross-border capacity allocation* in the intraday time frame. This time frame becomes increasingly relevant as vRES contributions increase, since the intraday market facilitates corrective program adjustment in response to (typically significant) shifts in vRES production forecasts after day-ahead. However, section 3.2.3 illustrated allocative inefficiencies in the intraday cross-border allocation between France and Germany, and section 4.2 identified misalignments that remained unresolved between the intraday markets and intraday cross-border capacity. Improvements in this domain, in line with the adjustments currently targeted by the joint XBID project, are likely not only to improve efficiency but also to enhance liquidity, which at present is more or less hampered in several of the PLEF intraday markets. Note also that since vRES generation typically evens out over a larger geographical regions (i.e. it shows declining levels of correlation with widening geographical range), improved cross-border trading should be expected to contribute significantly to market resilience in both the intraday as well as the overall short-term market.

75 See footnote 74.

6 Conclusions

A robust market design capable of facilitating the large scale introduction of renewable energy in the electricity markets will have to promote the effective allocation of flexibility. In this report, we reviewed the allocative efficiency of short-term electricity markets for flexibility in the PLEF countries on the basis of several fundamental principles of efficient pricing and allocation and on the basis of a detailed analysis of key market design parameters.

Our review suggests that, within short-term electricity markets, the balancing markets stand out as the market segment showing the greatest variety in both design and implementation strategies throughout the PLEF region. Many PLEF countries do not yet have in place critical marginal pricing requirements, as stipulated in the Network Code on Electricity Balancing. Often, the remuneration of balancing energy is based on pay-as-bid pricing, and pro-rata activation mechanisms are generally applied to secondary reserves. Imbalance settlement pricing is often based on averaged balancing market prices combined with additional incentive components and is therefore unlikely to reflect the real-time value of energy. Accordingly, our empirical analysis (based on descriptive statistics on pricing and allocation in four of the PLEF countries) reveals a number of instances of significant divergence from efficient pricing and allocation in real-time. Efficient pricing in the balancing markets and imbalance settlement is key in facilitating efficient resource allocation in the preceding day-ahead and intraday markets (where most of the flexibility is traded). The implementation of related provisions as stipulated in the Network Code on Electricity Balancing should contribute significantly to overall efficiency in the allocation of flexibility. Short-term market resilience would also thereby be enhanced in face of the large-scale introduction of renewable energy.

Beyond the dynamics internal to each segment of the market, our assessment addressed cross-market pricing, allocative efficiency, and arbitrage. The sequence of short-term market segment activity should result in the required allocative efficiency, on the planning horizon (in time) as well as throughout the PLEF region (in space). Our assessment acknowledges the critical role played by the intraday market in linking the day-ahead market time frame with the balancing market time frame. The intraday market segment facilitates the integration of non-dispatchable renewable energy resources, like solar PV and wind power, precisely because it enables schedules to be adjusted in response to updated information in the production forecasts. While allocative efficiency in the intraday time frame should be significantly affected by the design of the balancing market – reinforcing thereby the need for a robust balancing market design – we have seen it is also severely affected by misalignments between the intraday market and intraday cross-border capacity allocation. A better alignment based on improved implicit cross-border allocation (including the value of cross-border transmission capacity) is not only likely to improve efficiency but also to enhance liquidity, which at present is hampered in several of the PLEF intraday markets.

The findings in this assessment therefore identify several short-comings in the current design of short-term markets that compromise efficient flexibility provision in the PLEF region. The detailed evaluation of underlying drivers that we have undertaken here suggests there are pathways open to market enhancement that both complement and largely align with initiatives recently put in place in the PLEF region to improve the design and integration of short-term markets for electricity.

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